CLIMATE POLICY INITIATIVE

The Role of Public Finance in Deploying Geothermal: Background Paper

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San Giorgio Group Report

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Related CPI Reports	San Giorgio Group case studies	
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About CPI

Climate Policy Initiative (CPI) works to improve the most important energy and land use policies around the world, with a particular focus on finance. We support decision makers through in-depth analysis on what works and what does not. We work in places that provide the most potential for policy impact including Brazil, China, Europe, India, Indonesia, and the United States.

Our work helps nations grow while addressing increasingly scarce resources and climate risk. This is a complex challenge in which policy plays a crucial role.

Executive Summary

Geothermal energy is broadly cost competitive with fossil fuel alternatives even without a carbon price. The levelized cost of geothermal electricity is around 9-13 USDc/kWh, making it one of the cheapest renewable energy options available. **Its ability to provide low-cost, low-carbon power reliably and flexibly means is well-placed among to meet developing countries growing energy needs while displacing polluting fossil fuel power plants.**

However, its rate of deployment has been slower than other renewables over the last thirty years and will need to speed up rapidly if this technology is to deliver on its promise. In addition, geothermal technologies that can harness lower temperature geothermal resources need to achieve more deployment to bring costs down.

76-90% of geothermal project investments utilize some aspect of public debt or equity support.

This report is part of a project carried out by Climate Policy Initiative (CPI) for the Climate Investment Funds (CIFs) which will focus on the effective use of public finance to scale up geothermal deployment in developing countries.

The public sector plays a significant role in financing geothermal with 76-90% of project investments utilizing some aspect of public debt or equity support. Much of the current support targets the operational phase of the project but these public resources might be better used to address the risk in the exploration and field development phases.

The private sector has demonstrated willingness to invest in geothermal technologies but little appetite for investment in the early exploration and drilling phases of the project. This is a significant barrier to further geothermal expansion in many markets.

Furthermore, public-private partnerships still play a limited role despite their potential for attracting additional private capital.

Private Sector Reluctant to Accept Resource Risk

The resource identification and exploratory drilling phase is the riskiest part of geothermal project development and the biggest barrier to obtaining financing as it increases investors' equity returns requirements. Costs related to exploration drilling can reach up to 15% of the overall capital cost of the project. Resource availability is highly uncertain. Global success ratios of wells drilled during the exploration phase are estimated at 50-59% (IFC, 2013b). Longer lead times due to the resource identification and exploratory drilling phase, together with a large initial equity commitment usually required prior to debt financing, means investors demand a higher return for their equity investment (IFC, 2013a).

There is little appetite from the private sector to fund projects where the nature and extent of the resource are unknown. The private sector only financed all stages of the project in 7.5% of the utility-scale projects in our database. 58.5% of projects had the costs entirely borne by the public sector, while 34% projects had the private sector bear costs at later stages in the development chain once the resource had been proved. This is due to significant development costs when there remains a large degree of uncertainty on the viability of the project (ESMAP, 2012).

Resource exploration risk still affects the financing of the project during the production drilling phase. The effect of learning during the exploratory drilling phase means rates of success rise to 74% (IFC, 2013b) in the production drilling phase. However, the remaining resource uncertainty combined with the high capital expenditure necessary during this later phase means resource risk is still relevant. As a consequence most private financiers are not willing to provide financing until all or at least 70% of the MW capacity has been drilled (Audinet and Mateos, 2014).

Policy support mechanisms for geothermal are increasingly focusing on resource availability, but much of the current support focuses on the operational phase of the project. International and national efforts in particular are increasingly focusing on the reduction of geothermal drilling risk on an international scale, on resource identification and exploration, and measures to increase the viability and attractiveness of geothermal projects to energy investors (Armstrong et al. 2014). However, much of the current support available remains for the operational phase of the project (Speer et al, 2014), such as through feed-in tariffs or quote obligations such as renewable portfolio standards (ESMAP, 2012). New approaches are needed to reduce all geothermal project risks.

Key questions for future analysis

This background paper has led us to identify the following questions as key to determining more effective ways for public finance to drive geothermal deployment in developing countries:

- How effective or cost-effective are different policy and public investment tools?
- How can international public finance best support national policy efforts in developing countries?
- How can public support be reduced over time, shifting to a higher contribution from private finance?
- How can risks be addressed across the project development chain, and in particular the exploration phase?
- What are the characteristics, pros and cons of available financial structures and project development models? How effective are they in ensuring bankable projects?
- Do financing instruments and development approaches need to be tailored to technology types?

These questions will inform the analysis of three projects in three different regions using the San Giorgio Group case study approach:[1] Sarulla (Indonesia), Olkaria III (Kenya) and Gumuskoy (Turkey). The findings of this analysis will shed light on how public money can be used most effectively to further advance this renewable energy technology.

1 CPI's San Giorgio Group (SGG) case study approach uses a systematic analytical framework to explore project stakeholders' roles, their respective sources of return, the risks involved and risk mitigation arrangements employed to draw lessons for replicating and scaling up best practices.

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1. Introduction

In light of the need to transition to a low-carbon energy system, geothermal power is particularly interesting because of its ability to provide power reliably and flexibly to both meet base load energy demand and respond to fluctuating supply from technologies such as wind and solar PV depending on a power grid's needs.[2] In addition the cost of geothermal is competitive when compared to other renewable energies and – in many cases - fossil-fuelled generation. However, 13.1 GW installed globally by the end of 2013 (12.1 GW if we exclude decommissioned plant), is less than 10% of estimated global potential,[3] while current annual rates of deployment of geothermal capacity have been relatively steady at around 350 MW per year on average since the end of the 1970s. This is well below the 2,400 MW needed annually up to 2035 in a low-carbon energy scenario (IEA, 2013). This is mainly because resource risk and the high costs of drilling remain significant barriers to investment.

This background report is part of a project carried out by Climate Policy Initiative (CPI) for the Climate Investment Funds (CIFs) which will focus on the effective use of public finance to scale up geothermal development in developing countries. CPI will provide an overview of the geothermal sector and experiences from existing projects in key developing countries. The objective of this effort is to learn from the experience in developing geothermal projects, exploring viable ways to achieve economies of scale, reduce risks and costs, enabling countries to fully tap into their geothermal resources. The project will improve knowledge on the effectiveness of CIF funding on the development of geothermal energy[4] and help policymakers and donors understand how to shape their financing tools in order to enable effective and cost-effective promotion of geothermal energy.

To achieve this, CPI will carry out case studies of three projects in three different regions, using the San Giorgio Group case study approach: Sarulla (Indonesia), a CIF-supported project, and Olkaria III (Kenya) and Gumuskoy (Turkey).[5] The research on geothermal projects will be complemented by three geothermal dialogue events to share lessons and receive feedback from key experts on geothermal development.

The background paper provides an overview of trends geothermal sector and key issues for analysis in the case studies that follow. Section 2 describes current geothermal sector development with a focus on geographical distribution and technologies used; **section 3** focuses on the development process of a typical geothermal project and its costs compared to other technologies, as well as the typical risks and barriers; **section 4** introduces approaches used in the financing of geothermal projects and existing forms of policy support. The paper concludes by identifying key questions that CPI will address in upcoming case studies, and describing the approach we will use.

2 Geothermal power production increases the reliability of the power system, by providing a continuous source of clean energy, which can substitute fossil fuels (coal and gas) as a baseload power source. Furthermore, the flexibility and balancing needed by intermittent renewable energy such as wind and solar (Nelson, 2014), can be provided by geothermal as it can ramp up and ramp down electricity generation depending on the grid needs (GEA, 2012). For a more detailed discussion of the value of geothermal to the power system, see Matek and Schmidt (2013).

3 Global projected installed capacity of geothermal power plants is between 140 GW and 160 GW by 2050(Goldstein et al., 2011).

4 In October 2013, the Clean Technology Fund (CTF) of the Climate Investment Funds (CIF) approved the Utility Scale Renewable Energy Program as a new Dedicated Private Sector Program (DPSP) (CIF, 2013). The program will foster private sector involvement in geothermal drilling for resource identification and confirmation, the riskiest phases of geothermal energy development. An initial USD 115 million will support projects in four CTF countries with high geothermal potential, namely: Chile, Colombia, Mexico and Turkey. The program received additional pledges of USD 120 million from donors in June 2014 to expand coverage to other countries, such as Kenya, Indonesia and the Philippines. On top of CTF's DPSP, CIF is providing USD 608 million in concessional financing to support geothermal projects led by the public and private sector through the CTF and Scaling Up Renewable Energy Program in Low Income Countries (SREP).

5 See Annex III for more information on the selection process and the projects.

2. Global Geothermal Development

The rate of geothermal deployment has been slower than other renewables over the last thirty years and will need to speed up rapidly if this technology is to deliver on its promise.

While deployment in some mature markets is slowing, growth in market leaders and new emerging markets, and new technologies that allow the exploitation of lower temperature geothermal resources is compensating for this.

In general, countries are showing a strong interest in developing geothermal resources, particularly when they can benefit from high-temperature resources.

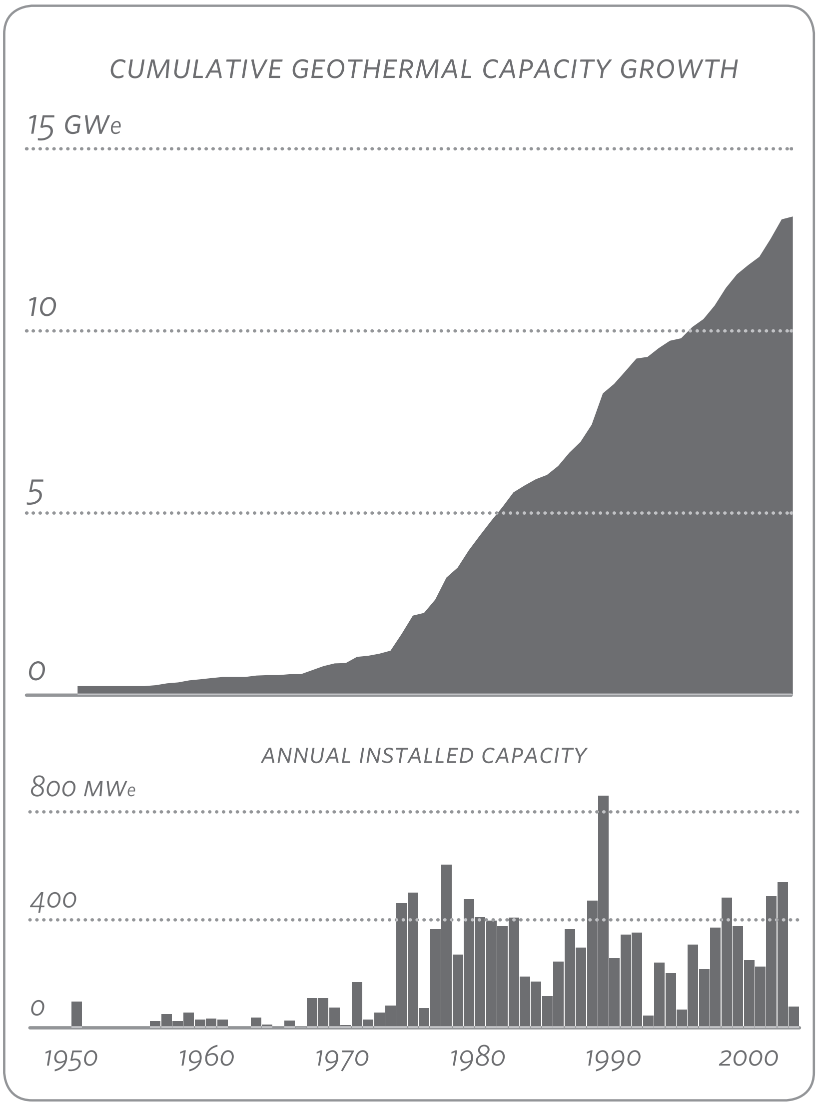
Currently, 20 countries have more than 10MW in installed geothermal capacity of the more than 50 already exploiting or planning to exploit their geothermal resources.

There are three main types of technology commonly used for generating geothermal electricity, and more innovative ones are beginning to be deployed. They are at different stages of market development and may require different kinds of public support.

After accelerating in the late 1970s, growth in geothermal installations has been relatively stable compared to other renewable technologies. Global installed capacity stood at 13.1 GW by the end of 2013 and geothermal has never added more than 860MW in a single year (see Figure 1). In contrast, wind energy surpassed geothermal capacity in 1997 and solar energy did so in 2007. They now stand at 308 GW and 145 GW respectively. In 2013, wind and solar energy added 32GW and 41GW of new capacity globally (BNEF, 2014a).

Currently, further acceleration in the growth of geothermal plants is limited by the higher risks and longer timelines associated with their development (see section 3) and the limited amount of easily accessible sites. While commercially usable wind and solar energy resources are available in many parts of the world, to date geothermal deployment has been limited to places with the most accessible high temperature resources (ESMAP, 2012).

Figure 1: Cumulative and annual geothermal capacity installed

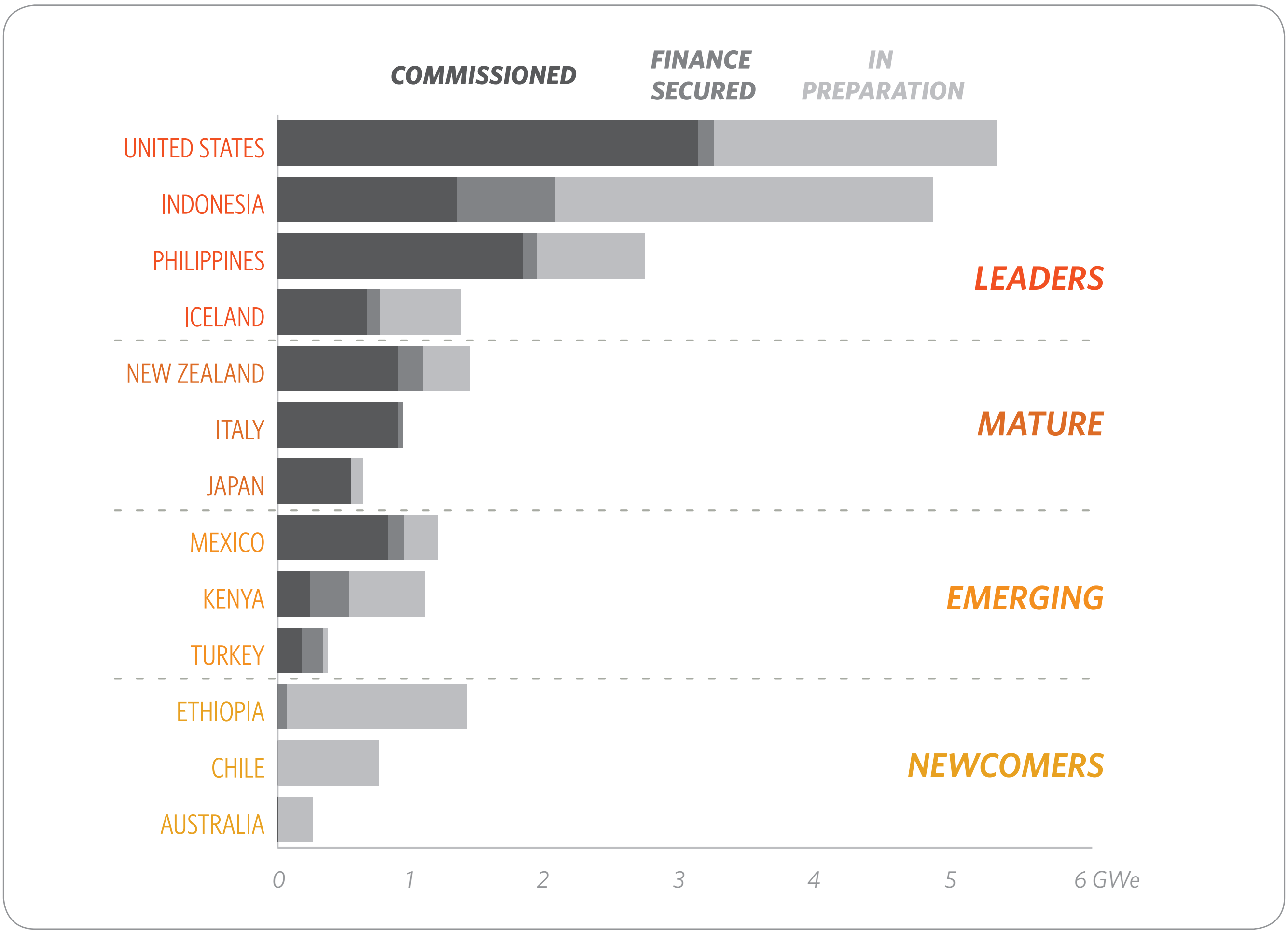


Source: GEA 2014c, CPI analysis. The graph shows all newly installed capacity. As a consequence it also tracks plants which are now decommissioned. Excluding decommissioned plants, total installed capacity is 12.1 GW.

2.1 Geographies

Only a select few countries endowed with high temperature geothermal resources, are actively seeking to exploit the potential it may play in their national energy mix.

Figure 2: Key growth markets for geothermal electricity development



Source: BNEF (2014a), CPI analysis. Note: Other project databases (GEA, 2014c) report higher installed capacities but for purposes of consistency across financial and project data in the following sections we have used BNEF renewable energy project database (2014a). Projects "in preparation" are subject to higher uncertainty of completion (see section 3.3 for more information).

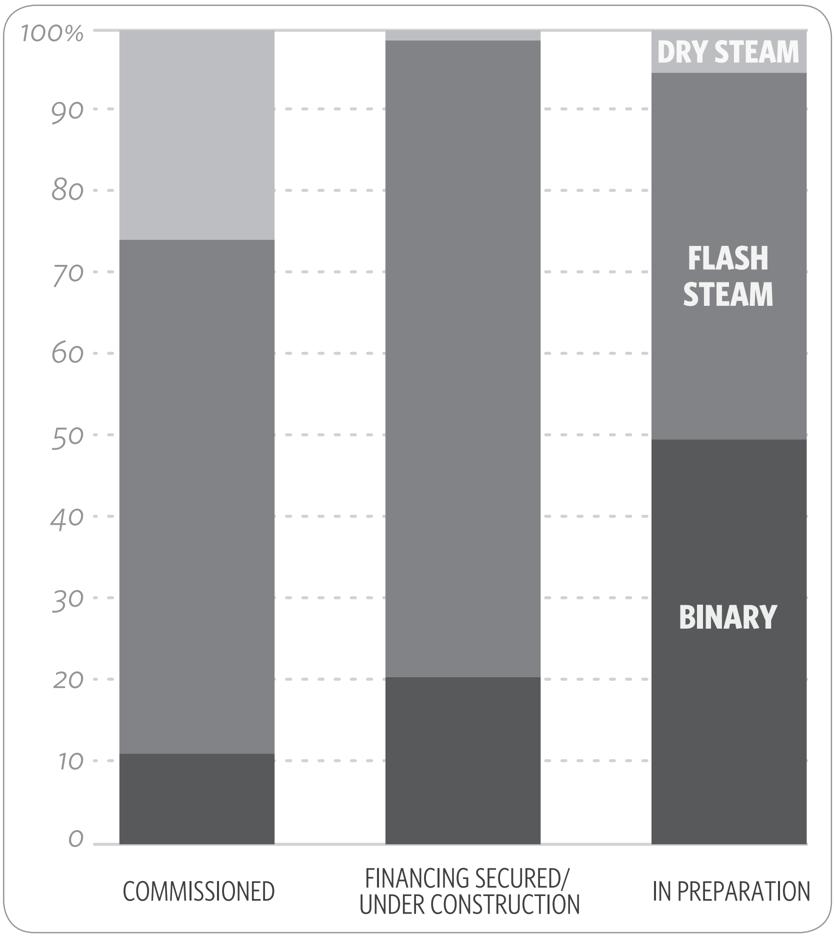
As shown in Figure 2, some countries have led this exploitation ('leaders' in the figure below). In other countries, deployment has slowed down in recent years ('mature'). In recent years, a few key growth markets have emerged from a low base ('emerging') while other markets are just starting to enter the space ('newcomers').

The U.S. hosts the largest share of global installed capacity and transferred their early experience to the Philippines, which has become the second largest geothermal producer. The U.S. accounted for 27% (3.1GW) of global installed capacity at the end of 2013. Almost two-thirds of it was added in the late 70s and 80s when the U.S. government mandated utilities to purchase power from renewable installations at its marginal costs. The high natural gas prices at the time coupled with the guaranteed power purchase and federal loan guarantees made geothermal plants a cost-effective source of electricity. As gas prices fell, the support policies became less attractive (Doris et al., 2009) and since 1990 only 730MW has been added.[6] This may change however with over 2GW of capacity in the pipeline, renewed mandates for renewable energy across several states rich in geothermal resources (GEA, 2014b), and continuous policy support to projects particularly in their operational phase (Speer et al., 2014).

The Philippines benefitted from early U.S. industrial experience from 1979 with Chevron building out 600MW of capacity (Catigtig, 2008). The country has since grown to become the second largest geothermal producer with 1.9GW installed or 16% of global capacity by the end of 2013. The Philippines is seen as a model of geothermal development, with the state company Energy Development Corporation (EDC) executing functions around exploration and drilling risk and a

6 500MW were installed after 2005, when new geothermal projects were made eligible for the U.S. renewable energy production tax credit in the Energy Policy Act of 2005 (GEA, 2013a).

Figure 3: Current and future outlook for different geothermal technologies (% of MWe)



Source: BNEF (2014a), CPI analysis. Over the years project developers have increasingly favored binary technologies, which allows the exploitation of medium to low temperature geothermal resources.

gradual liberalization of the electricity market since 1990 allowing private finance to participate in project development (ESMAP, 2012).

Indonesia is the leading growth market for geothermal today. While the country currently has just 1.3GW of installed capacity, it has the highest share of global capacity financed or under construction with 35% (721MW), and the most in the preparation phase (in drilling, permitting or planning phases) at 22% (2.7GW). However, it has not followed a smooth growth pattern – the Asian financial crisis hampered the realization of 4.5GW of concessions awarded to both public and private developers in 1991(World Bank, 2011). In addition, persistent bureaucratic barriers such as permitting and land acquisition continue to curtail development (GEA, 2014b).

Beyond these leading markets, contraction in mature markets is being compensated by a new group of developing countries, which are starting to develop their geothermal potential. There is little activity underway in Italy, Japan, and New Zealand (4th, 8th and 5th in installed capacity globally) where there is less electricity demand growth, while Iceland (7th) continues to gradually tap its resource potential. More activity is underway in emerging markets such as Kenya, Turkey, and Mexico where increases in electricity demand are driving growth. Kenya has the second largest number of projects reaching financial close after Indonesia with 287MW financed, in the main, by multilateral development banks. In Turkey, the private sector has actively pursued development opportunities for known geothermal resources with up to 170MW reaching financial close.

Finally, Ethiopia, Chile, and Australia, with little history of geothermal development, have significant projects in preparation to develop geothermal electricity. Ethiopia in particular, has the third largest portfolio in the preparation phase – 1.3GW in planning or permitted – after the U.S. and Indonesia. Although most of the projects are developed by the state-owned Ethiopian Electricity Power Corporation (EEPCO), the largest project is the 1GW private sector-led Corbetti development by Reykavik Geothermal (BNEF, 2014b).

2.2 Technologies

There are three main types of technology commonly used for generating geothermal electricity (Figure 3) and they are at different stages of market development. While dry steam plants were the most common in the 70s and 80s, flash steam plants have since established themselves as the most common form of geothermal electricity and binary plants currently represent the fastest growing form of geothermal electricity technology, especially in the U.S. In the meantime, new geothermal technologies like enhanced geothermal systems (EGS) are beginning to be deployed.

The fluidity and temperature of the geothermal resource affects the type of technology used.

25% of global installed capacity is in *dry steam plants* mostly due to the technology's early application in the 70s and 80s. Dry steam plants utilize existing pure hot steam from the reservoir (e.g. geysers) to directly drive a turbine. This type of reservoir is rare and mostly found around tectonic hot spots and volcanic areas where reservoir temperatures are above 200 degrees Celsius (°C) in as the U.S. (California), Italy, Indonesia, Japan, and New Zealand.

***Flash steam plants* are the most common form of geothermal electricity utilization due to their efficiency.** Flashing refers to the process of decompressing the hot water in the reservoir and capturing the resultant steam to drive a turbine. The remaining hot water may be flashed twice or three times in a cycle at lower temperatures and pressure. Because of the efficiency of this process, 60% of global installed capacity utilizes flash steam plants. The technology is the standard for temperatures above 180 °C.

***Binary plants* are particularly suitable for lower temperature sources.** While being a small part of installed capacity they currently represent the fastest growing form of geothermal electricity technology, especially in the U.S. Binary plants possess the capability of capturing energy from low to medium temperature reservoirs. Here, a secondary fluid with a lower boiling point[7] and higher vapor pressure than water is used as working fluid to drive the turbine. Hot fluid from the reservoir is used to heat this working fluid through ground heat exchangers. Temperatures of approximately 150 °C are typically utilized but some plants have successfully mined reservoirs at 73 °C. While 11% of plants today apply binary technology, they represent 35% of projects in the pipeline[8] mainly located in the U.S. This is partly due to the fact that significant higher temperature resources are still in early stages of development in less mature markets.

Over 98% of project capacity under development aims to generate electricity from conventional geothermal resources where hot steam or fluids are easily accessible. The remaining 2% are projects utilizing *enhanced geothermal systems (EGS).* EGS is a new innovative method that taps geothermal heat from hot rock sources by injecting water at sufficient pressure to open fractures and reservoirs. The potential for this method is significant. One-half of global projected installed capacity of geothermal power plants installed capacity is expected to be new Enhanced Geothermal System (EGS) type (Goldstein et al., 2011). However, the technology is not yet proven, and is not expected to become cost competitive until 2030 (IEA, 2011).

7 In an organic Rankine cycle (ORC) plant, butane or pentane is used, while a water-ammonia mixture is applied in a Kalina cycle.

8 By 'pipeline' we mean both projects under construction and in preparation for which data on technology application is available.

3. Project Development, Costs and Risks

On average, the development of a geothermal project requires approximately five and half years, longer than what is required for alternative renewable and conventional energy options.

Geothermal plants have low costs per unit of electricity generated but could increase competitiveness by reducing exploration, and field development costs.

Resource risk, combined with the long lead times from the start of exploration till the commissioning of the plant, contributes to the difficulties in attracting private capital finance until there is a greater certainty surrounding the resource capacity of the well.

Building bigger plants can reduce the investment cost per unit of electricity generated but impacts further on the timing for the development of the plant and can magnify resource risks.

3.1 Development phases and timing of a geothermal project

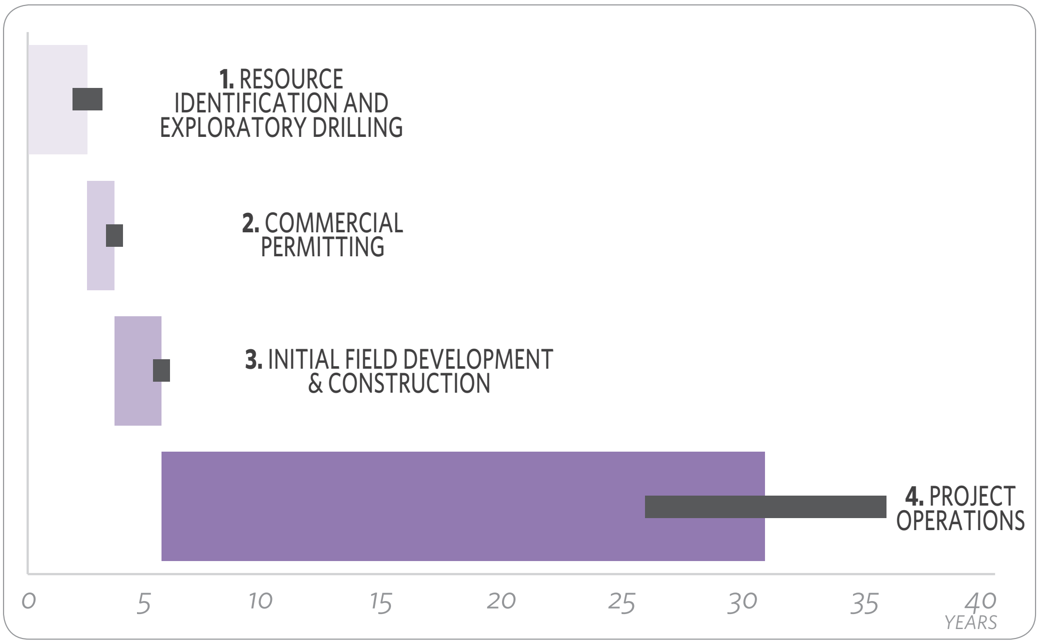
On average, the development of a geothermal project takes twice as long as many alternative renewable and conventional energy options, which impacts equity investors' return requirements.

An average geothermal plant requires approximately five and a half years (between 4 to 7 years from the securing of permits and licenses to the final commissioning and start of operations). This is more than the 1.5 years required on average to deploy renewable technologies such as solar and wind and more than the average 3.5 years needed for conventional sources such as oil and gas (GEA, 2014a). **The development of a geothermal project corresponds to 1/5th of the entire project lifetime** (see Figure 4), considering power plant operations[9] of about 20 to 30 years. Longer lead times, together with a large initial equity commitment usually required during the resource exploration phase prior to debt financing, means investors demand a higher return for their equity investment (IFC, 2013a).

Most of the time needed for the development of a geothermal project is dedicated to resource identification and exploratory drilling. This phase takes the same amount of time for larger and smaller projects, becoming then relatively more onerous for the latter.

The time required for *resource identification and exploratory drilling*[10] may vary widely, ranging 2 to 3 years depending on availability of information on the geology of the area, on the accessibility of the geothermal field, and on related regulatory and permitting issues.

Figure 4: Average geothermal development timeline and ranges



Note: The graph is based on observed BNEF values for three project development stages. The project operations timeline is based on figures provided by ESMAP (2012). To ensure consistency with BNEF classification used for data analysis we split the lifecycle of a typical geothermal project in three main development stages and a project operations stage. Black bars indicate time ranges for each phase.

9 During the operational phases the project owner ensures the full operations of the site, carrying out necessary maintenance work such as the cleaning of the existing wells and the drilling of new ones.

10 Includes all the preliminary work needed to assess the resource and initial pre-development approvals from local authorities, such as the acquisition of the land and the application for resource exploitation permits. After an initial pre-feasibility valuation of the resource, based on literature review and confirmed by geologic surface and subsurface surveys, the geothermal reservoir and its commercial exploitability is tested with the exploratory drilling of wells and interference tests to estimate its volume and potential.

With the exception of this phase, the overall time required for project development is directly linked to a plant's size. It increases by 20% for a typical utility size geothermal project larger than 50 MW, to a final range of 4 to 9.5 years. *Commercial permitting*,[11] requiring on average no more than one year, increases to up to 2 years for larger projects in relation to the stricter environmental requirements. *Initial field development and construction*[12] needs on average 2 years, rising to 2 to 3.5 years for projects larger than 50 MW. Variations on the timing of this phase depend significantly on the duration of the production drilling activity. This in turn is linked to the geology of the land used and, more importantly, to the dimensions of the geothermal project: the larger the project (and related field development), the larger the number of deep production (and reinjection) wells that have to be drilled.[13]

11 The developer secures approval by national authorities of all the necessary permits to carry on the production drilling of the site and the construction of the plant, including the approval of the final Environmental Impact Assessment (EIA). After the assessment of the financial feasibility of the project, the developer usually enters into a Power Purchase Agreement (PPA) with an off-taker.

12 Once most of the funds to develop the project are secured or approved, the developer announces the construction of a project following the signing of an engineering procurement and construction (EPC) contract or construction contract. The two key development steps of the project are the drilling of production and reinjection wells, and the construction of plant infrastructure and transmission linkages.

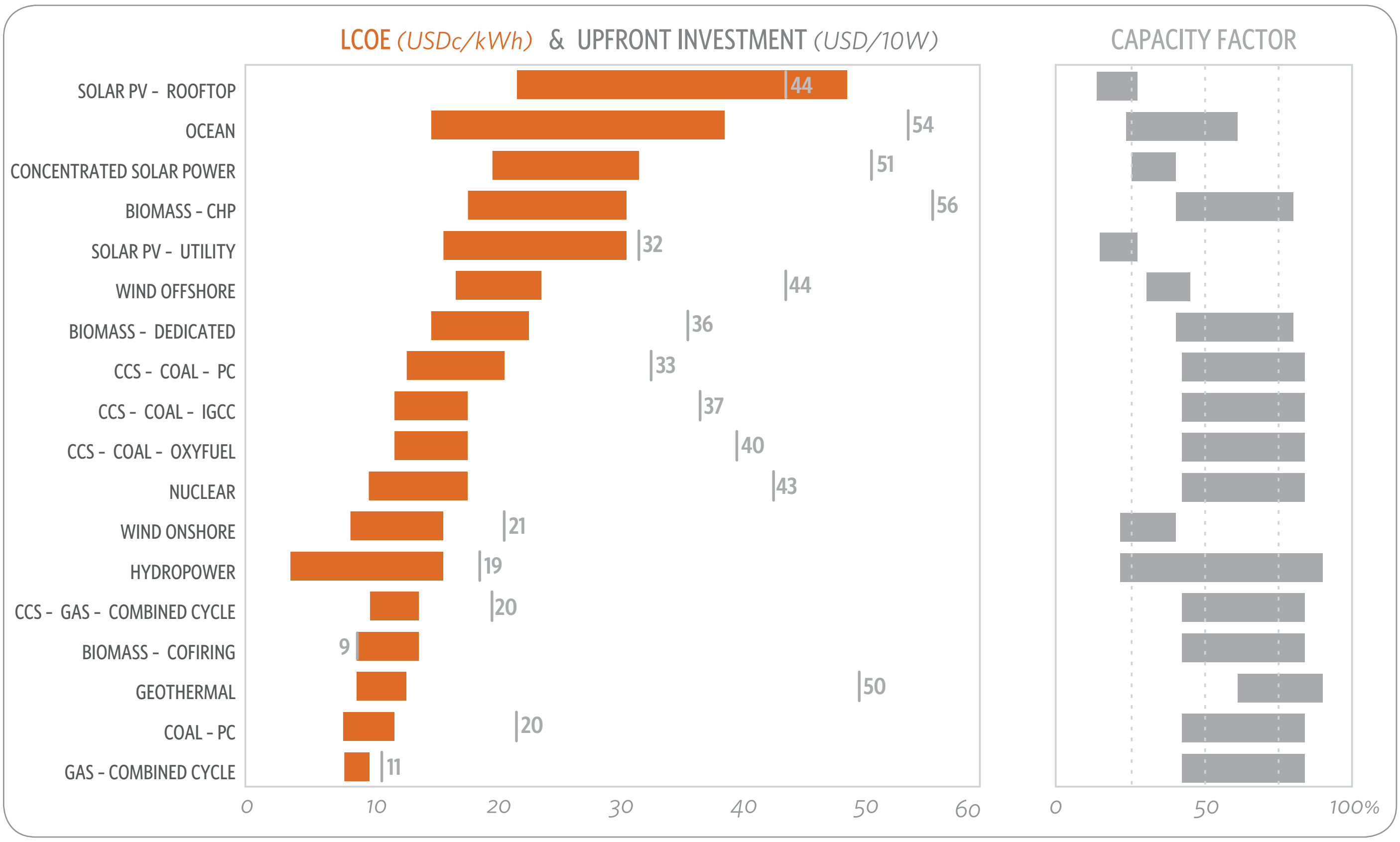
3.2 Costs of geothermal

Geothermal energy is broadly cost competitive with fossil fuel alternatives and among the cheapest sources of low-carbon power. Despite being a capital intensive technology, geothermal power plants have low costs per unit of electricity generated, partly due to its high capacity factors (EGEC, 2012).[14] The average levelized cost of electricity (LCOE) for geothermal is around 9-13 USDc/kWh, making it among the cheapest renewable energy options available. The low cost combined with the high capacity factor (see Figure 5) and the ability to continuously feed into the energy system makes it particularly suitable for baseload production.

13 It takes about six weeks to drill a normal 2 km deep well, or 40 to 50 days on average in volcanic environments (ESMAP, 2012).

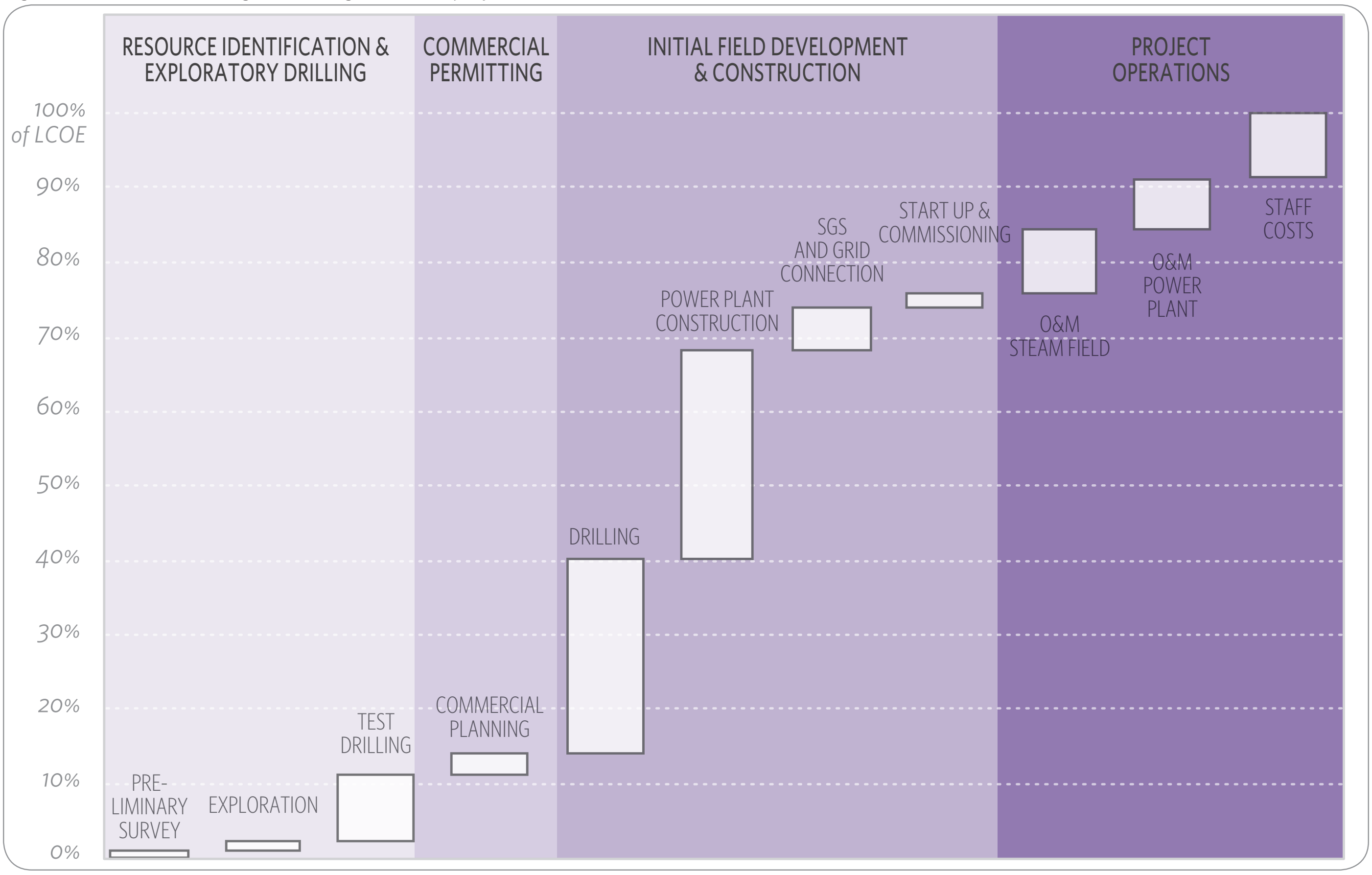
14 Capacity factor is the ratio between the annual production and the maximum technically possible production of the technology. Wind and solar PV's capacity factors are typically lower as wind doesn't blow and the sun doesn't shine all the time.

Figure 5: Cost comparisons between technologies



Note: Table based on IPCC WG III (2014). Values expressed in constant 2010 USD per 10W (capital expenditure) and 2010 USDc per kWh (LCOE). LCOE ranges are median values for a technology's low and high capacity factors. The cost of externalities generated (e.g. CO2 emissions) is not included. CCS = Carbon Capture & Storage; CHP = Combined Heat & Power; IGCC = Integrated Gasification Combined Cycle; PC = Pulverized Coal.

Figure 6: LCOE of an average 50 MW geothermal project



Note: Cost components of the LCOE of an average geothermal project of 40-60 MW size , assuming 25 years life-cycle and 10% discount rate per year of future electricity production. The LCOE of capital investment is based on observations from the BNEF database, each sub-component is estimated based on shares identified by ESMAP (2012). Operations and maintenance costs are sourced from ESMAP estimates for 50 MW plant.

Costs associated with initial field development and plant construction represent the highest share of geothermal generation costs. Remarkably, 11% of LCOE is due to the assessment of geological risk. As shown in Figure 6, initial field development and construction makes up more than 60% of the LCOE, particularly due to plant construction and production drilling costs. Exploration drilling represents 9% of investment costs, rising to 11% if we account for all the activities needed to assess geological risk during the pre-development phase of the project (i.e. preliminary surveys and surface exploration). These costs of locating and confirming the resource – which vary depending on the size and accessibility of the site, country regulations, and the availability of necessary tools and equipment – are a peculiarity of the geothermal sector.[15]

Excluding the operation phase, for which detailed data is not available for all projects, the main drivers of the levelized costs of geothermal electricity are the size of the plant constructed and the nature of the geothermal resource. Since 2005 levelized investment cost has been on average 7 USDc/kWh, or between 4 and 10 USDc/kWh.[16] The investment cost per unit of electricity generated is deeply affected by the size of the plant, decreasing by almost 50% when projects are larger than 10 MW. Expansions of existing projects also tend to cost less than newly developed fields. The levelized investment cost of projects seems to decrease when they benefit from higher resource temperatures (where levels of output produce are accordingly higher). Flash and dry steam technologies, associated with high resource temperatures, have similar average costs of 3.6 USDc/kWh and 3.2 USDc/kWh respectively. Binary technologies, often associated with lower and medium temperatures, are the most costly options with an

15 Unlike other renewables, in the geothermal sector it is not possible to carry out a power production feasibility study until the potential of the geothermal reservoir has been proven by drilling (ESMAP, 2012).

16 For the estimate of the levelized investment cost we looked at a sample of 46 projects from the BNEF database, namely projects for which information on both upfront investment costs at financing date and yearly output was available. We assumed these projects would have a 25 year life at 10% discount rate per year of future electricity generated. Values in the BNEF database reflect capital investment costs only, excluding operational costs sustained by the project developer. Values are expressed in constant 2010 USD. Enhanced geothermal system costs have not been assessed due to the limited experience derived from pilot plants.

average of 10.3 USDc/kWh. Binary systems can achieve reasonable and competitive costs in several cases, but costs vary considerably depending on the size of the plant, the temperature of the resource and the geographic location (EGEC, 2013), although this could change as technology for lower temperature improves.

Observed data on geothermal projects in different market across the world show that the levelized investment costs of projects are broadly stable (see Figure 7). Reduced costs due to learning on established technologies have been offset by the increasing deployment of more expensive smaller scale geothermal plants and binary technologies.[17] Levelized investment costs seem to be pretty consistent within a country across time, except for “leading” and “mature” markets such as U.S. and New Zealand where there have been more fluctuations due to different characteristics of the geothermal resources exploited.

Despite its competitive cost compared to other renewable energy alternatives, issues remain regarding geothermal power competitiveness with conventional fossil fuel technologies, which calls for the adoption of additional measures which help to level the playing field. Market distortions and lack of transparency in the electricity sector, as well as low CO_2 prices which do not fully reflect the cost of externalities, prevent geothermal energy from fully competing with conventional technologies in mature markets such as the EU.[18] This calls for the adoption of measures addressing current market failures to further increase the cost-competitiveness of geothermal resources.

3.3 Resource risks along the phases of project development

While most of the risks associated with the development of a geothermal project are similar to those faced by many grid-connected power plants (e.g. off-taker, resource, and policy risks), the high resource risk and level of investment required early on in the project combined with the time taken for the exploratory phase are unique to geothermal development (ESMAP, 2012).

The resource identification and exploratory drilling phase is the riskiest part of geothermal project development. The commercial viability of a well depends on the productivity of the field and on being able to tap into the resource itself. However, the exact depth of a well or the exact steam output from a geothermal well cannot be accurately predicted until the well itself is drilled. Exploration drilling phase results then are particularly risky, as the difficulty in estimating the resource capacity of a geothermal field - whose related costs can reach up to 15% of the overall capital cost of the project - combines with the high uncertainty regarding resource availability, where global success ratios of wells drilled during the exploration phase are estimated at 50-59% (IFC, 2013b).

The resource risks experienced in the early resource identification and exploratory drilling phase are seen as the biggest barriers to obtaining financing for geothermal exploration and extraction. There is little appetite from lenders to fund projects where the nature and extent of the resource are unknown. Further, geothermal projects also compete for private capital with mineral, coal, oil and gas exploration projects, which generally have greater certainty around returns and shorter development timeframes (Salmon, et al, 2011).

Resource risk does not disappear after exploration drilling, and still affect the financing of the project during the production drilling phase. Despite the strong learning-curve effect in geothermal drilling during the development phase – with rates of success rising to 74% (IFC, 2013b) – remaining resource uncertainty combined with the high capital expenditure makes resource risk still relevant. As a consequence most private financiers are not willing to provide financing until at least 70% of the MW capacity has been drilled (Audinet and Mateos, 2014).

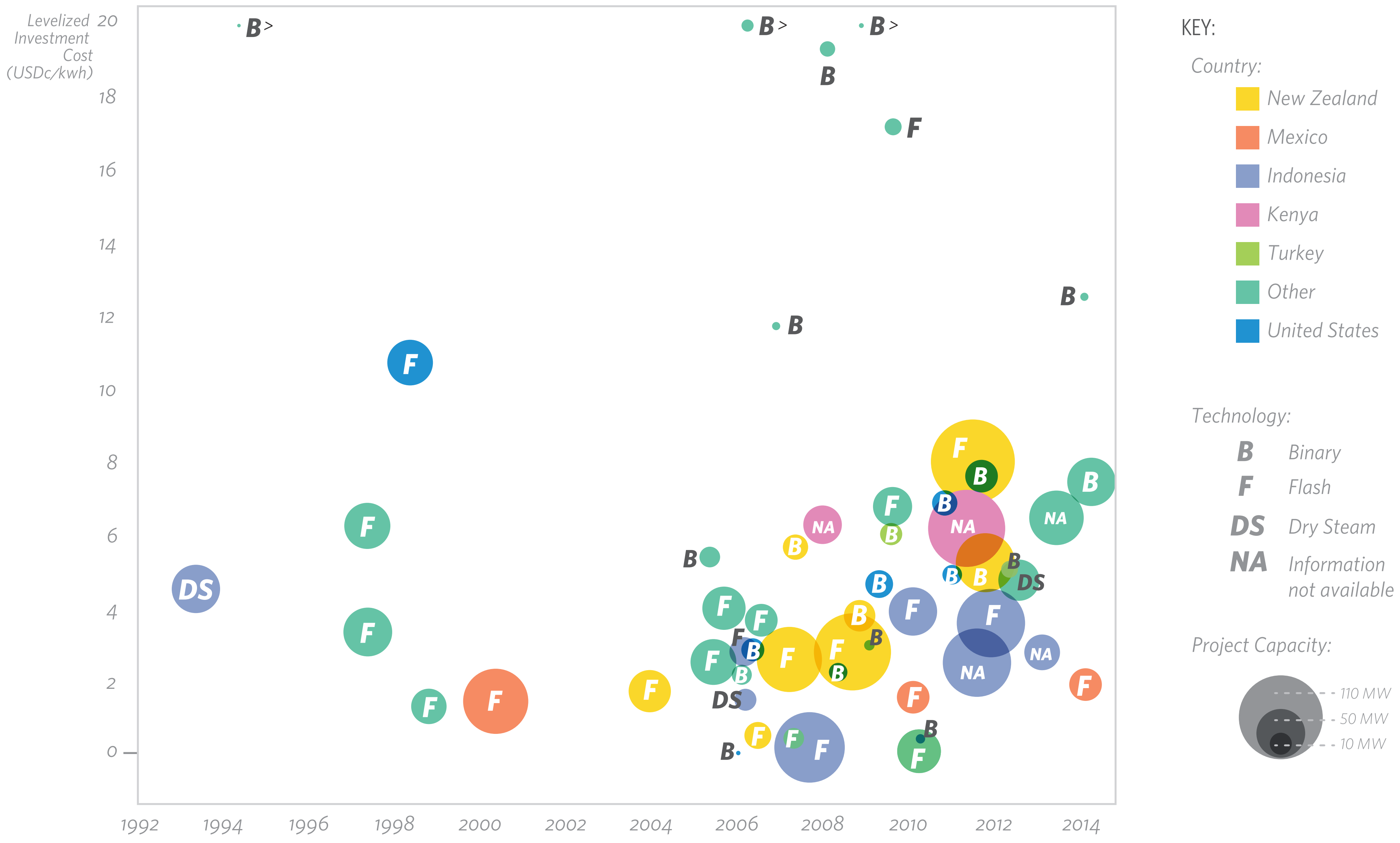
Resource risks can be magnified through the oversizing of the power plant and fields. Oversizing the plant concentrates investment resources in a given location—as opposed to spreading it across smaller plants in several geologically independent fields. Further, the amount of electricity that can be generated from the geothermal field is dependent on the number of wells that are drilled and each well’s production capacity, which also influences the economics of the well. However, excessive plant capacity can lead to unsustainable extraction rates resulting in pressure drops or even reservoir depletion (ESMAP, 2012).

Resource risk and the long lead times from the start of exploration till the commissioning of the plant contribute to the difficulties in attracting private capital finance. This calls for specific approaches for identifying sources of financing and public support.

17 Further reductions are expected in the long term as more plants are deployed.

18 Geothermal industry and research associations criticize imperfections in the current electricity market, strong fossil fuel subsidies - with electricity, nuclear and gas prices not reflecting the full cost of electricity generation - and the lack of market transparency to the customer (EGEC, 2013).

Figure 7: Comparison of levelized investment costs of geothermal in different countries



Note: Levelized investment costs expressed in constant 2010 USDc / kWh, assuming 10% discount rates; substantial early exploration costs are not available.

4. Financing and Public Support

Project finance models for geothermal rarely cover all development phases from exploration, drilling to power plant construction. They vary depending on the role of the public and private sector at each stage and on the location of the projects.

Public and private sectors provide equity finance for the large majority of projects independently of each other, while public-private partnerships still play a limited role.

The public sector plays a more important role in debt financing geothermal projects where 60-85% of project investments utilize public debt

In the case of geothermal, public support is mostly needed to address the risk in the exploration and field development phases as the private sector does not generally have the appetite for significant early-stage risks to survey, explore and confirm the feasibility of the underground reservoir

Policy support mechanisms for geothermal are increasingly focusing on resource availability, but much of the current support remains confined to the operational phase of the project

4.1 Sources of Finance

Finance structures for geothermal projects rarely cover the entire development chain of exploration, drilling and power plant construction. They vary depending on the role of the public and private sector at each stage. For example, where a state-owned power company develops geothermal, public finance may cover the entire project development costs. In contrast, when the private sector participates at a later stage, with tendering or concession based policy regimes, the structuring of the financing for the geothermal project may only refer to commercial drilling or power plant construction. In this case, only the power plant costs may be modeled as the resources have already been proven (see Annex 1 for more).

Irrespective of the extent of development stages covered, each project relies on a combination of development capital (equity) to cover business risks and investment capital (debt) to cover financial and credit risks. In our geothermal project database, covering utility-scale projects commissioned or financed since 2005, we found 53 projects where data on investment costs were available.[19]The main outcome from the analysis of existing cost structures is that:

- **Public sector and private sectors finance the equity investments of the large majority of projects independently of each other. Public-private partnerships still play a limited role.** In the majority of cases, public sector entities were the ones to invest in projects (government, municipalities, and State-Owned Enterprises). They either invested directly in the construction of the project or more commonly commissioned a private actor to build it while retaining ownership and operations rights (26 projects with USD 4.85bn mobilized). Private developers from the U.S., Turkey, Iceland and Italy have also largely contributed as lone providers of equity capital for the development or construction of the project (20 projects with USD 5 bn mobilized). Public-private partnerships (PPPs)[20] have played a limited role (7 projects with USD 1.12 bn mobilized) despite their potential for balancing risks across the different stakeholders and attracting additional private investment (OECD, 2008).
- **The public sector plays an even more important role in debt financing. 60-85% of investments mobilized for geothermal projects benefit from public debt.** In most cases debt capital is provided solely from the public sector, typically at concessional terms (20 projects with USD 4.65bn mobilized). The rest of debt financing is spilt into debt capital from both private and public sources (with the latter typically offering concessional terms), and projects financed entirely privately through bank loans or bond markets, only in very few cases supported by public sector risk instruments like guarantees and revenue subsidies.

19 Of the 53 projects, 23 had no information on debt capital provision, but we were able to identify the following sources of debt capital for the remaining 30 projects that mobilized USD 8 bn in total. Utility-scale is defined as projects greater than >50MW. Projects which expanded existing plants to >50MW in different phases were also included. We identified early-stage development costs where possible through company documentation.

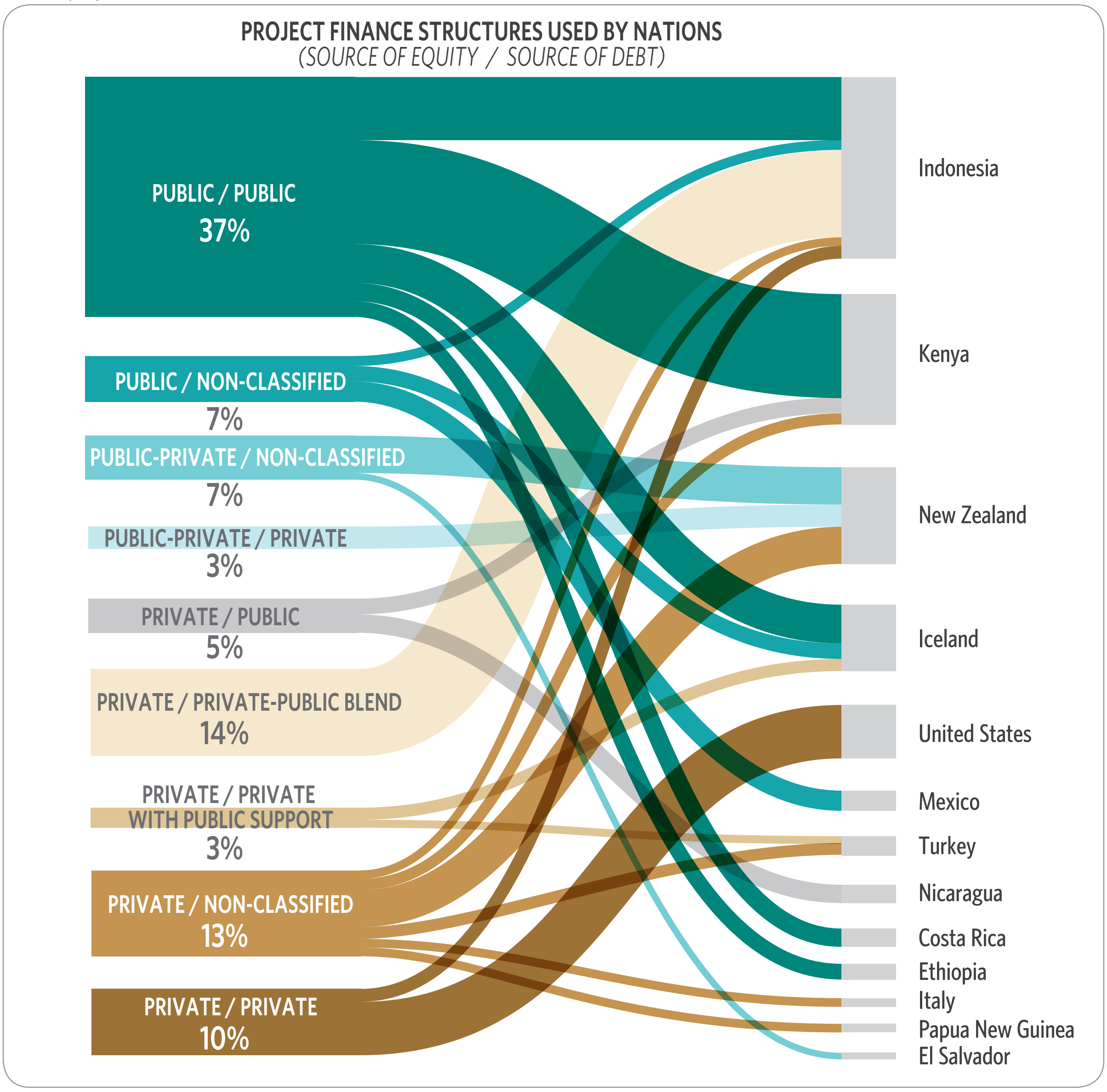
20 For PPPs here we refer to a blend of public and private equity capital for the development of the project, most typically, through a joint venture or a majority publically owned utility. PPPs can also take the form of a tolling, or energy conversion agreement, under which a public entity develops and operate the steam field, which is then converted into a plant operated by a private developer (Audinet and Mateos, 2014)

- **Whether financing is sourced from public or private sources is highly dependent on the location of the projects.** Private finance for both debt and equity is particularly prevalent in developed markets such as the US and New Zealand. These same U.S. companies have also developed projects in Kenya or Nicaragua with development bank debt finance (see Figure 8). Both Kenya and Indonesia have a mix of public and private sources with State-Owned Enterprises (SOEs) and Independent Power Producers (IPPs) developing projects with development bank debt finance. Local or international development banks also finance state-owned utilities in countries where there is less private participation in the power sector such as Costa Rica, Ethiopia, and Iceland.

Overall, the public sector plays a significant role in financing geothermal with 76-90% of project investments utilizing some aspect of public debt or equity support. There are two main reasons for this high share:

- SOE-led projects in developing countries supported by multilateral development banks, which make up half of the total
- The need to cover resource and development risks. With appropriate policies and public finance tools, a greater share of private finance might be expected.

Figure 8: Aggregate geothermal investment estimated per different financing structures, classified based on public/private sources of finance for debt and equity



Source: BNEF (2014a), project and company documentation, CPI analysis

4.2 Public Finance Mechanisms to Support Geothermal Projects

Government policies have the potential to drive the development of geothermal through technology development, risk reduction, barrier reduction and price equalization with conventional energy sources.

In the case of geothermal, public support is mostly needed to address the risk in the exploration and field development phases as the private sector does not generally have the appetite for significant early-stage risks to survey, explore and confirm the feasibility of the underground reservoir. For the utility-scale projects in our database, only in 7.5% of cases did the private sector finance each stage of the project. The public sector bore the costs for 58.5% of projects; while in 34% of projects the private sector bore costs at later stages in the development chain once the resource had been proved (see Annex 1). This is due to significant costs of the exploration and development phases where there remains a large degree of uncertainty on the viability of the project (ESMAP, 2012).

Policy support mechanisms for geothermal are increasingly focusing on resource availability, but much of the current support remains confined to the operational phase of the project. Policy support for geothermal includes revenue and fiscal policies, and policy tools to reduce financing costs (see Table 1). In particular, international and national efforts are increasingly focusing on the reduction of geothermal drilling risk on an international scale, on resources identification and exploration, and measures to increase the viability and attractiveness of geothermal projects to energy investors (Armstrong et al. 2014). However, much of the current support available remains for the operational phase of the project (Speer et al, 2014), such as through feed-in tariffs or quote obligations such as renewable portfolio standards (ESMAP, 2012), and new approaches are needed to reduce all geothermal project risks.

Table 1 – Current policy support mechanisms for geothermal

REVENUE POLICIES	Revenue support mechanisms aim to encourage private investment in geothermal projects by increasing the value or certainty of the project's revenues and assisting in overcoming upfront capital hurdles.
	• Feed-in Tariffs are set by the government and provide a minimum price, and thus revenue, which companies can expect to receive for electricity generation from the geothermal plant. They have been the most common form of revenue support for geothermal in countries such as the U.S., Germany, the Philippines, and Kenya. Countries such as Germany and Turkey also use bonus feed-in tariffs to encourage certain types of geothermal development or to encourage use of local manufacturing content (IEA, 2014). • Quota Obligations, such as the Renewable Portfolio Standards, provide a target for electricity generation from renewable sources over a designated period. They have been a key driver of geothermal development across the U.S. • Competitive Tenders are a bidding process to construct and operate a geothermal plant of a specific size at the electricity price fixed in the power purchase agreement between the winning bidder and the power distributor (Indonesia, U.S.). They have potential to foster competition and drive down costs but can lead to complex transactions for single plants.
FISCAL POLICIES	Fiscal support policies act to reduce the tax burden, increase net revenues and reduce operating costs through changes to fiscal regulations for geothermal projects.
	• Investment Tax Credits are available for the investor equal to a specific percentage of the investment in geothermal. For example, in the U.S. a tax credit of 10% of investment can be claimed for geothermal heat pump systems placed in service before the end of 2016. Its impact relies on the investor having enough income to benefit from the tax break. • Production Tax Credits come in the form of a per-kilowatt-hour tax credit for electricity generated by geothermal projects, as is the case in the U.S. • Accelerated Depreciation: Governments offer a period of accelerated depreciation of part or all of a project's assets, according to specific operating requirements, as in Mexico, the Philippines and the U.S. This allows return on investment to be achieved sooner.
TOOLS TO REDUCE FINANCING COSTS OF INVESTMENT	Tools that reduce the financing costs of making an investment include loan guarantees and concessional financing terms. These forms of support are necessary when returns from investments are not high enough to compensate the risks perceived by private investors, which can be an issue in the early phases of geothermal.
	• Loan guarantees: A government agency, multilateral development bank or public entity provides a guarantee of full or partial debt repayment to a lender in the event of borrower default (E.g. the U.S. Department of Energy Loan Guarantee Program or the World Bank support to Indonesia). This incentivizes private investment without necessarily or immediately having to draw on public finances. • Public grants (including concessional loans): A government entity, multilateral development bank or public entity provides a grant to assist with project costs, or provide a concessional loan with below-market rates and conditions, as has occurred in Kenya and Indonesia. The government can fund (or share the risk for) surface exploration, exploratory and confirmation drilling, provided that private investors absorb the risk associated with confirmation and production drilling (Audinet and Mateos, 2014). • Public insurance is where the government provides partial-cost reimbursement for unsuccessful drillings in the exploratory phase. The reimbursement is paid in the event that the exploration phase does not result in a predetermined level of success for a given project. This was seen as a key policy in the development of Iceland's geothermal sector. It has been drawn on less and less as the sector has become more experienced but has seen little replication in other countries (Speer et al, 2014).

5. Conclusions

Geothermal energy can play a key role for low-carbon energy systems due to its baseload nature and cost competitiveness with fossil fuel alternatives. However, long development times for projects and the risks associated with drilling and unproductive wells hamper private investment and the financing of geothermal projects.

- Geothermal energy has low costs per unit of electricity generated compared with other renewable technologies, but more has to be done to increase competitiveness with conventional fossil fuel technologies.
- On average, the development of a geothermal project requires five and a half years, more than many alternative renewable and conventional energy plants. This is mostly due to the timing needed resource identification and exploratory drilling.
- The public sector plays a significant role in financing geothermal. Long timelines, high resource risks, and significant resource exploration costs make it difficult to attract private capital finance until there is greater certainty surrounding the resource capacity of the well. Furthermore, public-private partnerships still play a limited role despite their potential for attracting additional private capital.

To achieve their full potential geothermal projects need appropriate policy, regulatory and institutional settings and risk mitigation instruments.

- In the case of geothermal, policy support is mostly needed to address the risk in the exploration and field development phases. Policy support mechanism for geothermal are increasingly focusing on resource availability and related risks, but much of the current support remains confined to the operational phase of the project.

The key questions raised by our research on the role of public finance in supporting geothermal development in an effective and cost-effective way are:

- How can policy, regulatory and institutional settings support geothermal development? How effective or cost-effective are different policy and public investment tools? How can international public finance best support national policy efforts in developing countries?
- How can we reduce public support over time, shifting towards a higher contribution of private finance?
- How can risks be addressed across the project development chain, in particular during the exploration phase?
- What are the characteristics, pros and cons of available financial structures and project development models? How best are they in ensuring bankable projects?
- Do financing instruments and development approaches need to be tailored to technology types?

These questions will inform the rest of our work in this series, namely the analysis of three projects in three different regions, using the San Giorgio Group case study approach:[21] Sarulla (Indonesia), a **CIF-supported project**, and Olkaria III (Kenya) and Gumuskoy (Turkey) as **non-CIF case studies**.[22] The research on geothermal projects will be complemented with three geothermal dialogues to share lessons and receive feedback from key experts on geothermal development. The experiences arising from these projects and the dialogues will shed light on how public money can be used most effectively to further advance this renewable energy technology.

21 The San Giorgio Group (SGG) case study approach uses a systematic analytical framework. Under this approach case studies explore in depth the role of project stakeholders, their respective sources of return, the risks involved and risk mitigation arrangements, and case-specific developments in order to draw lessons for replicating and scaling up best practices. The San Giorgio Group case study approach has been successfully implemented in a previous research project commissioned by CIF covering CSP projects in India (Reliance) and South Africa (ESKOM), further consolidating the methodology tested in four previous case studies: one CSP project (Ouarzazate, Morocco), one solar thermal project (Prosol, Tunisia), two wind power projects (Walney, UK, and Jadraas, Sweden).

22 See Annex III for more information on the selection process and the projects.

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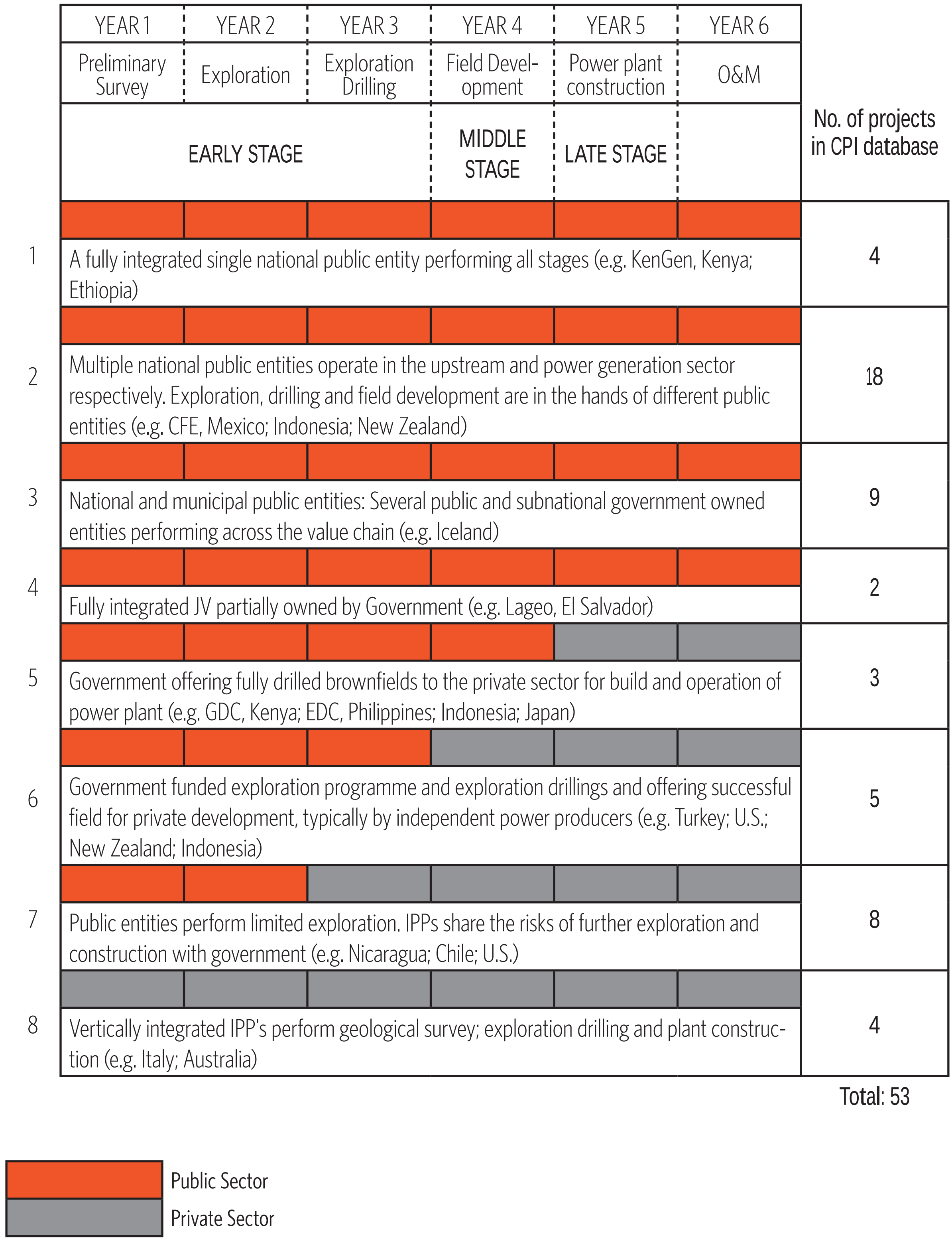
Annexes

Annex I - ESMAP models on Geothermal Power Development

ESMAP (2012) identifies 8 models for geothermal power development internationally, 7 of which involve all or a part of the development chain to be undertaken by the public sector.



Adapted from ESMAP (2012) Geothermal Handbook

Annex II - Geothermal project lifecycle

Several institutions have reconstructed the typical life cycle of geothermal projects, defining the phases of development based on implementation steps. Most analysis in this paper is based on BNEF data. This table relates these definitions with the classification BNEF applies to all renewable projects.

		THIS REPORT	ESMAP (2012)	GEA (2011, 2014B)	BNEF (2014A)
1	First assessment of geothermal area based on nationwide or regional study or, on available literature and data. If studies are not available developers can identify potential areas independently, through satellite and airborne imaging. Main components of the assessment include: -A literature survey of the geothermal sources, revealing generally favorable conditions for commercial development -A geologic survey have been done that identifies - and map - potential areas with viable geothermal resources	Resource identification and exploratory drilling	Preliminary survey	Resource Procurement and Identification	
2	The project developer acquires ownership of the land for the development of the plant, or alternatively obtains access through lease or concession from the surface and subsurface owners (e.g. the Bureau of Land Management).				
3	The project developer secures permits and licenses, such as surface rights and ≥50% mineral rights, as well as water rights and environmental permits.				Announced / planning begun
4	Exploration plan definition and execution, with surface and subsurface level surveys (e.g. geophysical and geochemical surveys) to confirm preliminary phase assessment and commercial viability of the site.		Exploration		
5	Pre-feasibility study (initiated the concession is granted or the field is selected) is finalized, comparing old data with the results of the new surveys under the exploration plan, exploring the likelihood of the existence of a commercial geothermal reservoir and the reservoir properties. The "surface exploration" phase is completed.				
6	Resource is evaluated for the first time by carrying out a volumetric resources assessment, which will be complemented by exploratory drilling in the next phase.				
7	Permitting for the exploration drilling is submitted, or obtained from the appropriate state agencies.				
8	Appropriate drilling program is defined to confirm existence, exact location, and potential of the reservoir.		Test Drilling	Resources exploration and confirmation	
9	Drilling of slim holes or full size wells (well stimulation may be needed to increase permeability and volume flow of geothermal fluids or steam into the borehole.)				
10	Exploration drilling completed, revealing potential for commercial geothermal well				
11	Interference tests between the boreholes to understand how wells are interconnected, and assess the size and shape of the reservoir. At the end of the process the developer has adequately characterized the fluid flow within the geothermal reservoir and determined its sustainable capacity with accuracy.				
12	Permit for production well drilling applied for, or approved.	Commercial permitting			Permitted
13	Feasibility study completed, using results from exploration drillings and financial calculations. EIA is also required and finalized for major projects		Project review and planning	Permitting and initial development	
14	EIA finalized. EIA is required for any major project that also would need to deal with the drilling phase in the case of geothermal.				
15	The developer evaluates existing data, and determines the most economically advantageous project size and investment necessary.				
16	Having completed the financial and technical feasibility study, the developer usually enters into a PPA with relevant utility or other power consumers.				
17	The developer has submitted, and been awarded a permit application for the construction of the geothermal power plant.				
18	Feasibility study and PPA allows developers to approach financiers and reach financial closure.	Initial field development and construction			Financing secured / under construction
19	The EPC contract has been signed.			Resource production and power plant construction	
20	Interconnection agreement signed between the developer and the identified utility. And transmission service request studies have been completed				
21	Drilling of production and reinjection wells is underway. The drilling process itself consists of alternating phases of drilling and well casing construction and cementing, until the top of the resource is reached.		Field development		
22	Pipelines to connect the wells to the plant begin to be constructed.				
23	Construction of steam and hot water pipelines is underway, including the installation of steam gathering system (SAGS) and of the separators.		Construction		
24	Equipment needed to build the plant is on order				
25	Construction of power plant and cooling is underway, including the construction of the turbine, the generator and the cold end.				
26	Construction of the substation and transmission grid for the supply of electricity generated is underway.				
27	Resolution of contractual and technical issues with the supplier of the plant. E.g.: Verification of minimum performance conditions defined in the contract with the construction company.		Start-up and commissioning		
28	Operations and maintenance of the steam field (wells, pipelines, infrastructure)	Project operations	Operation and maintenance	Operational Phase	Commissioned
29	Operations and maintenance of the power plant (turbine, generator, cooling system, and substation).				

Annex III – Overview of case studies selected

Case studies have been identified based on the following selection criteria: a geographical balance across studies, coverage of all stages of development and implementation, with prospects of substantial lessons through different use of instruments and presence of private finance. Final projects were chosen based on feedback from external stakeholders.

	COUNTRY	FINANCING	CIF	PRO	CON
Sarulla 351MW	Indonesia	ADB $250m loan; JBIC $533.6m loan; CTF $80m; Canada $20m; Comm. banks $255.7m	Y	Public-private finance leverage	Recent financing closure

Summary: Sarulla is a 351 MW geothermal power project of three separate units, in the North Sumatra Province of the Republic of Indonesia. The project is particularly interesting for its size - once it comes online, it will be the world's largest geothermal power project - and for the integrated financing of its three separate units, as opposed to the incremental financing approach usually pursued to allow for "proving up" geothermal reserves.

The project's capital structure involves a mix of public and private finance: direct loans for USD 250m and USD 533.6m from ADB and JBIC respectively, senior debt tranches from by CIF and the Canadian Climate Fund, and importantly commercial loans for about USD 255m benefiting from a political risk guarantee provided by JBIC.

	COUNTRY	FINANCING	CIF	PRO	CON
Olkaria III 110MW	Kenya	OPIC loans $310m; DEG loan $105m; MIGA PRI and WB PRG	N	Mix of risk instruments; public-owned Olkara sites I/II/IV to compare	Limited priv. finance leverage on debt side

Summary: Olkaria III is a 110 MW geothermal power plant located in Kenya and the deal is the first privately funded and developed geothermal project in Africa. The project registers a good mix of financing and risk mitigation instruments made available to private developer: initially equity financed, it benefits of OPIC's concessional loan facility with USD 85m refinancing of phase 1, USD 180m made available for the expansion of the project and USD 45m standby loan for further expansion. The project also benefits of a DEG loan of $105 used to refinance phase 1; risk is covered by a MIGA political risk insurance and WB partial risk guarantee.

A CPI case study on Olkaria III may also cover Olkaria IV, focusing on the RFP process being followed for the selection of the private counterpart.

	COUNTRY	FINANCING	CIF	PRO	CON
Gumuskoy GPP 13.2 MW	Turkey	EBRD MidSEFF $24.9m loan; a $9.6m lease finance loan; and $15m equity (70:30% debt to equity ratio)	N	Local private developer and significant private investment	Small scale project

Summary: Although smaller in scale at 13.2MW, the Gumuskoy GPP developed by local company BM Holding, meets the case study criteria of significant private sector involvement and financing throughout the development cycle. It was the first private sector high enthalpy geothermal discovery in Turkey in 2008.

In 2004, the public authority Mineral Research & Exploration General Directorate (MTA) discarded the field due to limited surface manifestations and failed shallow exploration attempts. However, BM discovered a deep reservoir and, in 2009, flow tests confirmed plant feasibility. The project was financed with a debt to equity ratio of 70:30 through an EBRD MidSEFF USD 24.9m loan; a USD 9.6m lease finance loan; and USD 15m equity.