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ASSESSMENT OF EXPLORATION STRATEGIES, RESULTS AND COSTS OF GEOTHERMAL FIELDS IN INDONESIA

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ABSTRACT

This study evaluates exploration methods, strategies, results and costs of 5 geothermal projects in Indonesia. Observations are compared to reported cases from other leading geothermal countries. Exploration strategy plays an important role in determining success of the exploration stage. Consequently, exploration strategy determines commerciality and is important for decision making at the development stage gate. There is a gap in the Indonesian geothermal industry where significant elements of actual exploration strategies and costs have hardly been published with an actual reference. In this study, exploration methods, strategies, results and expenditures, along with total project costs are collected from feasibility studies, exploration reports and annual reports. Cost indices are used to reflect historical changes. This study adopted quantitative methods that involve descriptive-comparative analysis. Exploration variables are evaluated prior to conducting statistical examination of the findings.

In the 5 Indonesian geothermal projects the number of explorations wells ranges from 2 to 10 drilled from 1 to 5 well pads. Exploration drilling success ratio in the 5 projects ranges from 33 to 67%. The power density ranges from 6 to 15 MW/km^2 and the recent average exploration well output acquired from 29 wells in the 5 projects is 5 MW/well. The exploration cost in the 5 projects is expected to be in the range 15-40% of the overall planned project cost. This amounts to 0.6-2 million USD per MW which is significantly higher than in reference projects in other countries where the exploration cost was in the range of 0.2-0.8 million USD per MW.

1. INTRODUCTION

1.1 Background

Geothermal exploration is an initial and important stage in geothermal development. According to a study by Gehringer and Loksha (2012) in the ESMAP technical report, the exploration stage involves high costs and has the highest risk profile in geothermal project implementation. High upstream risk is influenced by the resource availability, success ratio of exploration drilling and exploration well

productivity. Furthermore, exploration strategy and cost represent geothermal developer's confidence in the resource, their attempt to unlock its potential and the efforts to reduce upstream risk before construction and development activities begin.

Geothermal cost has been the subject of many studies. Generally, exploration cost is the capital cost that is dispensed during the early stage of geothermal development. It covers geoscientific surveys, exploration infrastructure, exploration drillings and well testing. Several studies presented by Gehringer and Loksha (2012), JICA (2016) and Jacobs (2017) advise that cost of geothermal exploration from several fields in various countries in the world ranges from 15 to 22% for a development capacity of 20-110 MW.

Prior to 2003, geothermal enterprising in Indonesia was regulated by Presidential Decree No. 22 of 1981 which had entitled PERTAMINA, Indonesia's state-owned enterprise (SOE), through its subsidiary company Pertamina Geothermal Energy (PGE), the rights to develop geothermal energy. In the process of harnessing geothermal energy, aside from conducting their own operations, PGE has also been able to utilize Joint Operation Contract (JOC) mechanisms. The JOC scheme enabled foreign business entities to form partnership with PGE. Since 2003, new geothermal mechanisms enable private companies and other SOEs to participate in geothermal development under a new law. Under this new scheme, the Geological Agency, which serves under the Ministry of Energy and Mineral Resource (MEMR), represents the Government in preliminary exploration before geothermal areas are tendered to business entities.

New Geothermal law No. 21 of 2014, which revokes previous law No. 27 of 2003, governs that geothermal business permits (GBP) are granted to business entities by MEMR. GBPs are valid for the duration of 37 years. GBP consists of maximum 7 years for exploration and 30 years for development, construction, and utilization. Under this law, 19 private companies were given GBPs by the Ministry and Energy and Mineral Resources (MEMR) and have been involved in geothermal exploration from 2009 to 2019. Five companies operating in 5 geothermal fields have already completed their explorations and submitted feasibility study reports prior to conducting development and construction.

Furthermore, Articles 61-63 of Geothermal Law No. 21 of 2014 requires the Ministry of Energy and Mineral Resources to supervise and monitor exploration activities which are conducted by GBP holders and its incurred costs. At the same time, there is a gap in the geothermal industry in Indonesia and the actual exploration costs have hardly been published due to confidentiality issues. This may lead to uncertainties when determining assumptions of geothermal cost that should be based on actual references. Exploration cost reflects different exploration strategies that may be affected by the degree of confidence in the geothermal resource, development capacities, funding ability, involvement of foreign entities and the complexity of project management organizations.

1.2 Objectives

The aim of this study is to:

i. Briefly explain and compare different exploration methods and strategies that have been carried out recently in 5 different geothermal projects.
ii. Examine exploration project timelines to provide insight into constrains of completing the exploration stage in Indonesia.
iii. Evaluate exploration activities and correlation of the cost invested, which includes geoscientific surveys, infrastructure construction, exploration drilling, well testing and resource estimation.
iv. Compare exploration cost in Indonesia and exploration cost in other leading and emerging geothermal countries such as Iceland, Philippines, Turkey, New Zealand and Kenya.

The essence of this study is to provide an insight into actual and recent exploration strategies and associated costs that can be useful for future projects.

2. METHODOLOGY

2.1 Data collection and limitation

The data used in this study and their limitation can be explained as follows:

i. Exploration strategy, results and cost, along with total project cost is collected from feasibility study reports of 5 geothermal projects that already completed the exploration stage. Annual work programmes and budget reports enable this study to assess project timeline with regard to project planning and make an annual cost distribution comparison.
ii. Total project cost from the 5 geothermal projects will be compared to total project cost from several geothermal power plant projects around the world and studies from several institutions.
iii. This study uses cost index for calculating cost with reference to time to enable historical cost comparison. According to Newnan et al. (2004), cost indexes are numerical values that reflect historical change of costs. The numbers are dimensionless and reflect relative price change of individual cost (labour, material, utilities) or groups of costs (consumer prices, producer prices). Cost indices ratio relationship is described in Equation 1:

$$\frac{cost\ at\ time\ A}{cost\ at\ time\ B} = \frac{index\ value\ at\ time\ A}{index\ value\ at\ time\ B} \tag{1}$$

2.2 Data analysis methods

According to Gunnell (2016), research methodologies can in general be divided into quantitative, qualitative and a combination of quantitative and qualitative (mixed) methods. Qualitative methods are often used to analyse and evaluate non-numerical information with the aim to understand the important material and object behaviour by using specific variables. Quantitative methods often rely on statistical inquiry for interpreting numerical data. This study adopts quantitative methods that involve descriptive-comparative analysis and statistical examination.

A descriptive-comparative approach is carried out by collecting and observing information, then the variables are analysed. This study describes and explains technical and non-technical parameters (cost and organisational) which represent the exploration activities of 5 projects. Then the results are compared between projects to define exploration strategies and results. Each parameter used in this study is listed in Figure 1.

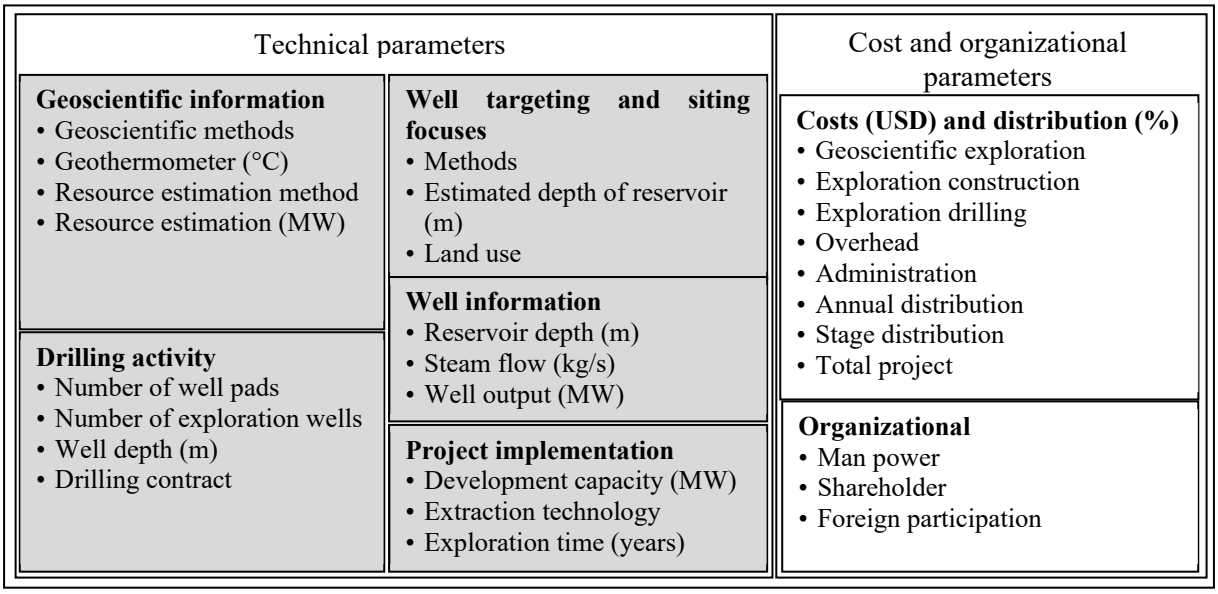


FIGURE 1: Exploration parameters covered by this study

Statistical analysis involves comparisons and distribution of the following parameters:

1. Exploration cost which consists of geoscientific exploration, exploration construction, exploration drilling, well testing, overhead, and administration;
2. Exploration cost per MW during exploration stage;
3. Annual distribution of exploration cost;
4. Project cost stage distribution which involves exploration, development and construction cost;
5. Total project cost per MW development capacity.

3. LITERATURE REVIEW

3.1 Geothermal development

Geothermal development requires several steps to ensure risk reduction, technical implementation and cost optimization. IGA (2014) and Gehringer and Loksha (2012) explain that important stages in geothermal developments are:

1. *Preliminary survey.* This activity requires evaluations of the power market (power purchase agreements/PPA), identification of other possibilities for geothermal utilization, infrastructure condition, regulation, political, environmental and social issues, other issues relating to political and financial stability, required permitting, remote sensing or aerial survey data, information from available geoscientific data, and information from previous explorations or wells.
2. *Exploration.* This stage consists of a detailed geoscientific survey to delineate the geothermal prospect and to minimize uncertainties related to estimation of main reservoir parameters. The result of the geoscientific surveys is then summarized in form of a conceptual model. Optional temperature gradient wells might be drilled to ensure that the geothermal prospect has the desired temperature. The results are resumed in a pre-feasibility report that includes an estimation of the resource and well target options for exploration drilling. Permits for exploration drilling should be prepared prior to drilling.
3. *Exploration/test drilling.* This stage is usually commenced by establishing the required infrastructure, drilling contractor procurement and contract, and purchasing of drilling material. Drilling of a minimum of 2-3 wells on 2-3 well pads is preferable to characterise the extent of the prospect. Well logging and testing are conducted after the drilling is accomplished. However, some fields require longer heating up times and well stimulation might be required to discharge geothermal fluid. The new information is used to refine the earlier conceptual model to delineate targets for production and reinjection wells. Well output from exploration wells can be used as a reference for production well productivity.
4. *Project review and feasibility.* The feasibility report is prepared using results from at least one successful production well. The production well is used as a basis for understanding the geothermal reservoir and to develop convincing numerical models. Investment decisions for field development and plant construction are based on the assurance level from this report. Information about development and construction costs needs to be estimated to build a profitable financial model and to obtain project funding prior to advancing the project. The report should also include location options and design for production and reinjection wells. Engineering parameters for power plant construction are also thoroughly defined within this report.
5. *Field development.* At this stage, production and injection drilling are carried out to ensure sufficient steam and required capacity for fluid disposal. In parallel to these activities, the development of steam field facilities (steam above ground system) and detailed engineering design for the power plant are usually finalized before the EPC tender process takes place. Project financing should be available after the majority of the resources were confirmed by development

drilling. PPA with the electricity buyer is finalized at this stage to provide security for long-term debt.

6. *Power plant construction and commissioning.* Construction of necessary civil infrastructure and commissioning of the power plant are typically carried out based on a single contract that has been agreed to by the owner, the main contractor and the power plant manufacturer through a single engineering, procurement, construction and commissioning (EPCC) contract awarded following a tender process. Several tests are required during commissioning to ensure reliability of the power plant prior to handover to owner.
7. *Operation and maintenance.* In this stage it is focused on optimization and sustainability of production. The balance between generation and steam supply from the reservoir has to be found. Minimizing operational and maintenance costs is essential to meet financial goals. Make up drilling, well interventions and plant maintenance are needed to ensure the reliability of electricity generation.

A comprehensive list of activities, risks and required costs of geothermal development is given in Appendix I.

Several authors consider only a simple 3-phases approach which consists of (1) exploration, (2) development, and (3) operations. The Indonesian regulatory framework governed by the Geothermal Law No. 21 of 2014 assumes 4 stages of geothermal development:

1. *Preliminary survey* consists of the collection, analysis, and data presentation of earlier geological, geophysical, and geochemical studies, and a temperature gradient survey if necessary, to estimate location and availability of the geothermal resource.
2. *Exploration* includes geological, geophysical, and geochemical surveys, test drilling, and exploration well drilling with the goal to gain information about the geological conditions under the surface, to locate and estimate the size of the reservoir. A feasibility study is carried out to determine the technical, economic and environmental feasibility of geothermal exploitation. Exploration and feasibility study take a maximum of 7 years.
3. *Exploitation* consists of a set of activities including drilling of development and reinjection wells, development of field facility and its support as well as production operations.
4. *Indirect utilization* is geothermal utilization by transferring thermal energy into electrical energy. This stage lasts for 30 years and can be extended by another 20 years.

3.2 Geothermal exploration concept

The purpose of exploration is to identify a geothermal resource, determine the extent of the resource (area and thickness), define reservoir chemistry, recognise reservoir temperature, build a conceptual model and estimate the potential energy of the prospect. Generally, exploration starts with conducting a reconnaissance study assessing previous work. This is followed by a site visit, geochemistry measurements and sampling and the collection of additional information. This stage is finalised with a recommendation to continue with detailed exploration studies if the exploitation of the resource is feasible (Richter et al., 2014).

Detailed geoscientific surface exploration studies are conducted for technically feasible projects. Study requirements (modified from Richter et al., 2014 and MEMR, 2017) mainly involve:

1. *Geological studies:*
   - Remote sensing, volcano-stratigraphy mapping, structural mapping, and preliminary hydrogeology mapping to delineate main prospect. The identification map should have a scale of at least 1:10,000;

- Rock sampling and analysis to identify geothermometers, age, and petrophysical characteristics;
- Thermal surface feature mapping which can be conducted parallel with the geochemical investigation; and
- Heat loss measurements to estimate the amount of concealed heat and mass flow and to associate thermal features to structure zones.

2. *Geochemical studies:*
   - Temperature and flow measurements, sampling of geothermal fluids, meteoric water sampling, water and gas identification, isotope analysis and geothermometer estimation;
   - Meteoric water sampling and analysis;
   - Soil diffuse mapping to analyse Hg, CO_2, and radon gases.
3. *Geophysical studies:*
   - Electromagnetic survey with spacing of less than 500-1000 m, production of resistivity maps with a scale of at least 1:10,000 to identify clay cap and reservoir;
   - Gravity measurement with spacing of less than 2000 m, production of a map with a scale of at least 1:10,000 to identify Bouguer anomaly and possible geological structure;
   - Magnetic mapping to identify demagnetised zones, intrusions and faults;
   - Passive seismic measurements to monitor micro-seismic activity. This survey aims to identify permeable structures in the reservoir.
4. *Geotechnical studies:*
   - Geological hazard mapping and soil mechanical characteristic identification with the aim to understand potential hazards and to provide detailed data for civil construction.
5. *Optional temperature gradient well*
   - Intended to identify anomalies in vertical temperature distribution
6. *Integrated data evaluation:*
   - Consists of interpretation of geoscientific data to construct a conceptual model to describe the clay cap, temperature distribution, up flow, out flow, and reservoir geometry. Well siting and targeting is proposed during this stage in case of an economically feasible resource. A preliminary resource assessment is carried out using the volumetric heat store method to quantifying magnitude of possible reserves.

Furthermore, it is important to complete preliminary studies such as environmental assessment and a pre-feasibility study for viable reserves prior to exploration drilling which will provide substantial information for land acquisition and civil construction such as roads and well pads. Exploration well design is needed to identify drilling targets, assess risk, estimate cost and provide precursor data for long lead material procurement and drilling equipment contracting. Well design contains the target depth, hole size, direction of well, drilling programme, geological prognosis, well cost, health, safety and environmental evaluation, risk assessment, contingency plan and well sequence.

Geothermal wells are mostly classified by the size of bit diameter:

1) Slim hole – production diameter hole of less than 8-1/2";
2) Standard hole – production diameter hole of 8-1/2"; and
3) Large/wide hole – production diameter hole of > 8-1/2", typically 12-1/4" or even 17-1/2".

It is crucial to assess and determine the casing size design in the exploration strategy. Slim hole drilling can decrease risk of failure and improve the probability of successful exploration. This approach can be useful for prospects where the resource size is uncertain and where funding is limited. Depending on location and drilling contract, a 2000 m deep well of standard or large size diameter costs approximately

7-8 million USD or up to double the cost of a slim hole well. However, conventional wells have the advantage of allowing extraction of steam to surface and can later serve as production wells.

The objective of exploration drilling is to confirm the presence of commercially exploitable geothermal reservoirs. To ensure discovery success ratio of 30-50% during exploration, 2-3 exploration wells need to be drilled from 2-3 different well pads. Based on the author's analysis, drilling of geothermal wells in Indonesia takes 35-65 days for a target depth of 2000-2700 m. Additionally, 2-3 appraisal wells are also needed.

After well completion, tests are performed with the aim to identify temperature and pressure distribution, to confirm reservoir properties, to locate feed zones and quantify well output. This activity involves downhole measurements (logging), a completion test, a well stimulation heating up test, and a production test. Depending on the reservoir conditions, well testing takes generally 1-3 months.

The capacity is estimated to assess if the resource is commercially exploitable when the preliminary survey, the detailed geoscientific survey and the exploration well testing are completed. Common methods of resource estimation are listed in Table 1.

TABLE 1: Resource assessment, modified from Indonesia National Standard No. 6482 (BSN, 2000), Saptadji (2017) and Pálsson (2019)

No.	Methods	Type of model	Remarks
1	Heat loss	Direct measurement	Estimate concealed heat loss by measuring heat flow from thermal features (springs, pools and fumaroles).
2	Power density	Comparison	Useful in reconnaissance surveys, where field data and evidence are limited; multiplication of power density of other fields (MW/km^2) by estimated area (km^2).
3	Volumetric	Estimation	Assumption that reservoir is a cubical volume with uniform reservoir parameters (lumped-parameter model); calculate heat energy by multiplying areas (m^2), reservoir thickness (m) and reservoir parameters; for early exploration and uncertain reserves estimation.
4	Numerical simulation	Dynamic	Assumption that reservoir is a cubical volume with heterogenic reservoir parameters (distributed parameter model); time-consuming process to build model based on measured actual reservoir parameters, reliable prediction of reservoir size and performance.

For resource estimation, Indonesia's national standard classification of resources and geothermal reserves is used to determine classification, types of resources or reserves, estimation methods and criteria. Geothermal companies are encouraged to comply to Indonesia National Standard No. 6009 from 2017 (Table 2).

TABLE 2: Resource classification according to Indonesia National Standard No. 6009 (BSN, 2017)

	Speculative	**Hypothetic**	**Reserves**		
			Possible	**Probable**	**Proven**
Methodology	Geology and geochemistry	Geology, geochemstry and geophysics (3G)	3G and/or temperature gradient	3G and/or temperature gradient and ≥ 1 exploration well	3G and/or temperature gradient and ≥ 3 exploration wells
Map scale	1:100,000	1:50,000	1:25,000 - 1:50,000	1:25,000	1:10,000 - 1:25,000
Temperature estimation	Fluid geothermometer	Fluid geothermometer	Fluid geothermo-meter	Direct wellbore temperature measurement	Direct wellbore temperature measurement
Fluid chemistry	Surface thermal manifestation	Surface thermal manifestation	Surface thermal manifestation	Direct wellbore measurement and well testing	Direct wellbore measurement and well testing
Resource estimation	Power density	Volumetric stored heat	Volumetric stored heat	Volumetric stored heat	Reservoir simulation

3.3 Geothermal project cost

For the case of Indonesia, geothermal project cost is mostly structured by assumptions and information about the following factors:

Commercial assumptions:

1. *Type of enterprise*: Existing enterprise, geothermal business permit – preliminary survey assignment and exploration might impose different fiscal advantages and state revenue obligations.
2. *Type of developer*: Private Independent Power Producer (IPP) company or State-Owned Enterprise (SOE); might have different requirement economic indicators.
3. *Type of development:* Green field (exploration and/or development has not taken place yet) or brown field (previous exploration and development has taken place).
4. *Project location*: Tariff attractiveness controlled by the Government through MEMR regulation based on National Electricity Company (Perusahaan Listrik Negara / PLN) production cost of electricity varies for each province.
5. *Debt and loan configuration.*
6. *Details of loans* (interest, repayment, tenure).
7. *State/government revenue*: Tax, levy, production bonus and royalty.

Technical assumptions:

1. Size of the project: determines the scale of power plant capacity development.
2. Infrastructure of road access.
3. Project schedule and expected time.
4. Prediction of reservoir temperature, enthalpy, reservoir depth, and expected well output.
5. Size, number of wells and depth of drilling.
6. Generating power plant technology.

Geothermal project cost in Indonesia has been the subject of many studies by various institutions. Typical investment cost in Indonesia ranges from 3 to 5 million USD per MW. Various studies on cost of geothermal projects in Indonesia and worldwide are summarised in Table 3.

TABLE 3: Geothermal project cost in Indonesia and worldwide

	Studies	Exploration (MUSD)	Development (MUSD)	Construction (MUSD)	Total (MUSD)	MUSD/ MW	Reference country
1	Gehringer and Loksha (2012) - ESMAP report	23 12%	77 39%	96 49%	196	3.92	Worldwide
2	Asian Developm. Bank and World Bank (2014)	78 22%	88 24%	194 54%	360	3.27	Indonesia
3	IRENA (2017) data from 2014	48 12%	107 26%	265 63%	421	3.83	Indonesia
4	JICA (2016)	52 20%	102 39%	109 41%	263	4.78	Indonesia
5	GT Management (2017)	88 32%	57 21%	128 47%	273	4.97	Indonesia

3.4 Worldwide exploration cost and strategy

Various entities and companies around the world practice different exploration methods. However, currently the most common methods for geophysical exploration mainly involve electromagnetic, gravity and passive seismic techniques. High spatial resolution measurements are essential to obtain a better estimation of the conditions in the subsurface. Methods and efforts of geoscientific exploration are subject to company requirements, area and site-specific conditions. Generally, the pre-feasibility study should be based on the results of preliminary exploration involving surface geoscientific exploration and environmental study. This stage imposes costs of approximately 1 million USD.

Further exploration entails construction of well pads, procurement of drilling material and equipment, exploration drilling and well testing. Well pads for conventional drilling generally range from 2 to 4 ha, whereas well pads for slim holes are typically less than 0.5 ha. It is essential to obtain items with long lead times and equipment required for drilling when the pre-feasibility assessment has been completed.

In Iceland and New Zealand, exploratory drilling is followed by appraisal drilling to achieve viable information for the feasibility study report (Pálsson, 2019; Jacobs, 2017). For investors it is essential to have detailed information about the reservoir. Jacobs (2017) states that appraisal drilling accounts for 7-11% of the total project cost. GT Management (2017) suggested the drilling of at least 5 delineation/appraisal wells using equity for a 55 MW project. Therefore, from a commercial point of view, the appraisal stage is an important stage prior to deciding whether to enter the development stage. Ngugi (2013) says that it is common in Kenya to drill 3-4 exploration wells followed by 6-9 appraisal wells to estimate feasibility and to decide which prospects are approved for development.

Department Order No. DO2013-10-0018 regulates that geothermal developers in Philippine have to undertake pre-development activities in the following order (DoE, 2013):

1. Reconnaissance survey and mandatory permitting within year 1;
2. Detailed exploration survey and pre-feasibility study in year 2; and
3. Permitting, civil construction, drilling of exploratory wells (3 wells), feasibility study and declaration of commerciality in year 3 to 5.

The costs of the preliminary survey, exploration and appraisal stage are worldwide in the range of 0.6-2 MUSD per MW. The cost varies in different countries and depends on the size of the project, resource extent, depth of drilling etc.

4. GEOTHERMAL DEVELOPMENT IN INDONESIA

4.1 Geothermal resources in Indonesia

Geothermal energy in Indonesia is generally associated with volcanism. According to Hamilton (1979) and Hall (2009), the presence of volcanism and tectonism in Indonesia is a result of the constant migration of lithospheric plates. The Indonesian archipelago is located on the Indian-Australian plate that slides northward were it collides with the south-westward drifting Eurasian plate, and forges a convergent boundary alongside the Indonesian coastal line, the volcanic arcs. These arcs extend from Sumatra in the west over Java in the south to Sulawesi and Maluku in the northeast. These arcs are regularly associated with geothermal resources.

Based on the geothermal distribution map of Indonesia, published by the Geological Agency (MEMR, 2018), it has been estimated that geothermal resources in Indonesia have a capacity of 25,386 MW (Table 4). These resources are located in 349 geothermal prospects that are spread from western to eastern Indonesia. MEMR gathered these data by conducting preliminary exploration studies and by assembling detailed exploration results of studies carried out by geothermal companies in their geothermal working area (GWA).

TABLE 4: Geothermal resources in Indonesia, modified from MEMR (2018)

No.	Islands	Prospect location	Resources (MWe)					Total resources	Installed capacity (2018)
			Specu-lative	Hypo-thetical	Reserves				
					Possible	Probable	Proven		
1	Sumatera	103	2,776	1,689	3,889	1,083	1,028	10,465	562
2	Jawa	73	1,190	1,460	3,708	516	1,820	8,694	1,254
3	Bali	6	70	22	122	110	30	354	0
4	Nusa Tenggara	28	225	210	829	121	12.5	1,397.5	12.5
5	Kalimantan	14	151	18	12	0	0	181	0
6	Sulawesi	89	1,360	362	1,041	180	120	3,063	120
7	Maluku	33	560	91	497	6	2	1,156	0
8	Papua	3	75	0	0	0	0	75	0
	Total	**349**	**6,407**	**3,852**	**10,099**	**2,016**	**3,012.5**	**25,386.5**	**1,948.5**
			10,259		**15,127.5**				
			25,386.5						

4.2 Brief history geothermal exploration

Hochstein and Sudarman (2008) documented the history of geothermal exploration in Indonesia from the 1920s to 2000. This report provides an update of the exploration activities from 2000 to 2018 (Appendix II, Table 1). The activities can be divided into 3 phases.

I. First phase - early attempt

1. *1920 – 1970:* The first documented attempt of exploration activities in Indonesia was started in the early 1920s, when geothermal prospecting was conducted in the Kamojang geothermal field followed by shallow exploration drilling down to 128 m depth. Other reconnaissance and exploration studies were conducted in Dieng followed by non-exploratory drilling where 140°C hot geothermal fluid was encountered.

2. *1971 – 1980:* In this period, other large exploration studies were conducted in Kamojang, Darajat, Gunung Salak and Bedugul prospects. The Kamojang geothermal field exploration and development took place in 1975 when a production drilling campaign successfully provided 232-243°C steam to support the first Kamojang power plant. Exploration of the Darajat prospect was

conducted in 1975 and the results indicated vapour-dominated steam. Preliminary studies of the Gunung Salak geothermal field were conducted from 1970 to 1975 and exploration drilling took place in 1975. Other preliminary surveys in Jawa Island were conducted in the Kaldera Danau Banten (Lake Danu) and Cisolok-Cisukarame geothermal fields. Other early exploration surveys outside Jawa Island were carried out in the Bedugul prospect in Bali, the Muaralaboh prospect in West Sumatra, the Sungai Penuh prospect in Jambi and the Lahendong and Kotamobagu prospects in Sulawesi by the Volcanological Survey of Indonesia (VSI).

II. Second phase - Presidential Decree No. 22 of 1981 and No. 45 of 1991

1. *1981 – 1995*: The Government of Indonesia issued Presidential Decree No. 22 in 1981 and No. 45 in 1991 which authorize Pertamina to conduct their own operation of geothermal fields and to cooperate with private investors to develop geothermal energy. The development progressed in Darajat and Salak fields after JOCs were signed with Amoseas Indonesia (Chevron Energy group) in 1982. They conducted a detailed survey, drilled 4 deep exploratory wells in Darajat up to 2300 m deep and 3 deep wells in Salak up to 1830 m deep. Pertamina continued the exploration by drilling 4 deep wells up to 2200 m depth in Lahendong to support the 20 MW development plan. In Nusa Tenggara, Perusahaan Listrik Negara (PLN), with the assistance of VSI a geoscientific survey and first exploration drilling up to 1890 m depth to support small scale development was conducted. Exploration drilling was also conducted in Sibual-buali and Silangkitang in 1994 to a depth of up to 2080 and 2000 m, respectively, after the JOC agreements were signed. Other preliminary geoscientific exploration studies were carried out in at least 35 new prospects across Jawa, Sumatera, Nusa Tenggara and Sulawesi, most of them by Pertamina. Most of the exploration studies, however, were not followed by exploration drilling.
2. *1996 – 2000*: During this phase, exploration in Indonesia was also continued in Sibual in Buali, in Suoh Sekincau in Sumatera, in Karaha Bodas and Ciater in Jawa, in Sokoria and Mataloko in Nusa Tenggara and in Tulehu in Maluku. However, the Government enacted the Presidential Decree No. 39 in 1998 which halted most geothermal power development due to fiscal and monetary reasons.

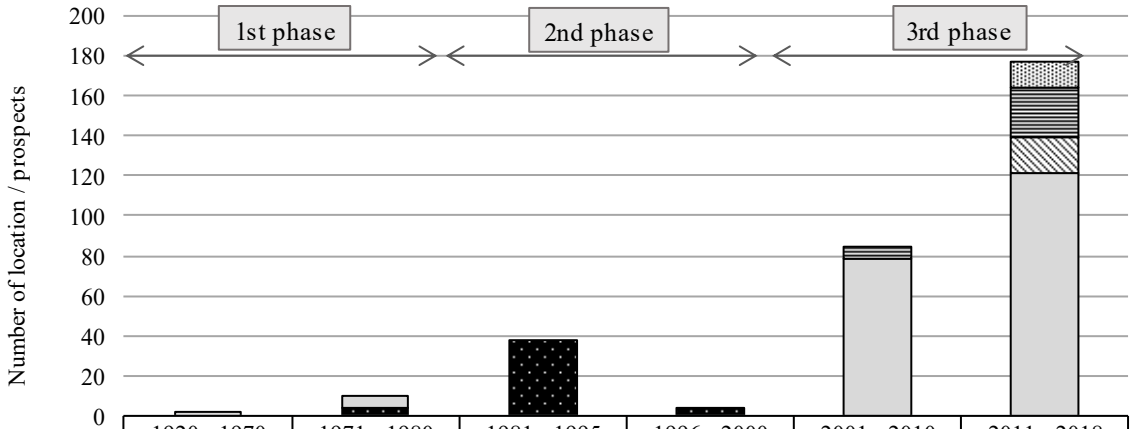
III. Third Phase – Geothermal Law No. 27 of 2003 and No. 21 of 2014

1. *2001 – 2010:* Geothermal exploration activity increased after the Presidential Decree No. 15 was issued in 2002. Subsequently, Presidential Decree No. 76 was issued in 2002 to adjust Pertamina's role in geothermal development. Pertamina returned 18 geothermal working areas (GWAs) to MEMR in 2002. This was followed by the first Geothermal Law No. 27, issued in 2003, which enabled participation of the private sector. The Geological Agency got the task to conduct preliminary geoscientific surveys which were required to complete geoscientific studies prior to tenders of 19 GWA in 2007-2009. The MEMR introduced two new schemes of geothermal enterprising:
   a. *Geothermal Business Permit (GBP):* This permit followed the GWA tender. The GBP is issued to the bidder which satisfies the entire tender requirements. The GBP holder must conduct geoscientific exploration, exploration drilling and a feasibility study within 7 years. During this period, the regional Government is responsible for monitoring and supervision.
   b. *Preliminary survey assignment (PSA):* This enables a business entity to conduct a preliminary survey without exploration drilling. This was decided in order to reduce upstream risk and attract potential investors. Hence, they were enabled to conduct investigations, not yet carried out by the Geological Agency (GA). In this scheme, the business entity is required to complete the geoscientific exploration within 1 year and present the pre-feasibility study to MEMR prior to the establishment of the GWA.

   In this phase, Pertamina and PLN continued exploration in 4 geothermal fields. They conducted exploration drilling in Ulubelu, Lumut Balai, Kotamobagu, and Tulehu. The exploration phase was successful in Ulubelu and Lumut Balai, but in Kotamobagu and Tulehu it did not confirm the expected permeability and temperature.

2. *2011 – 2019*: In 2014, Geothermal Law No. 21 revoked Geothermal Law No. 27 from 2003. It gives the Central Government control over exploration activities, allows the SOE to obtain direct assignments from the MEMR to conduct exploration studies, and revises the concept of the PSA which now became the Preliminary Survey and Exploration (PSAE), which included at least 1 exploration well. To fulfil the PSAE, business entities must complete geoscientific exploration and at least one exploration well within 3 years. In this phase, explorations of 12 PSAs, 19 GWAs and 13 PSAEs were completed. Five GBP holders have completed exploration within their GWAs and submitted feasibility studies.

Statistics of exploration activities in geothermal prospects in Indonesia by different parties, both government institutions and business entities, are illustrated in Figure 2.



	1920 - 1970	1971 - 1980	1981 - 1995	1996 - 2000	2001 - 2010	2011 - 2018
SOE	0	0	0	0	0	13
PSA & PSAE	0	0	0	0	6	25
GBP	0	0	0	0	0	18
VSI / GA	2	6	0	0	79	121
PERTAMINA	0	4	38	4	0	0

FIGURE 2: Exploration activities conducted in Indonesia by various entities from the 1920s to 2019 (modified and updated from Hochstein and Sudarman (2008) and Anna Yushartanti from the Geological Agency, personal communication, September 2019)

4.3 Present status of development and utilization

Geothermal law governs that development should commence as soon as the feasibility study is submitted and approved by the MEMR. Generally, completion time for geothermal projects is measured from the start of exploration to the first unit's commercial operation date (COD). For GWAs developed by Pertamina and through JOCs projects, the completion took approximately 8-11 years, e.g. in the Salak, Darajat, and Wayang Windu geothermal fields. However, in the Lahendong, Sarulla, and Dieng geothermal fields, the time of project completion ranged from 17 to 23 years. This was caused by a political and financial stand-down due to the financial crisis in 1997-1998 which forced the Indonesian Government to stop most infrastructure projects, negotiations of Power Purchase Agreements (PPA), and actions leading to changes in the ownership of fields and power plants.

For GWAs established after 2003, GBP holders are required to conducts exploration in 7 years. The Government requires GBP holders to return the GBP if the exploration is not completed. However, based on our evaluation geothermal project completion of new GWAs usually takes 10-11 years as can be observed in ongoing projects such as Muaralaboh, Rantau Dedap and Sorik Marapi.

Geothermal Law No. 21 of 2014 classifies utilization of geothermal energy in Indonesia into two types, i.e. direct use, and indirect use for electricity generation. Geothermal resources in Indonesia are predominantly utilized for electricity generation. In September 2019, the total capacity of geothermal power plants which had been commissioned and supported electricity generation in Indonesia was 2003.5 MW, which accounted for 8% of the estimated total available resources, of 25386.5 MW. Installed capacity from 1990 to 2019 is shown in Figure 3. The list of power plants can be found in Appendix II, Table 2.

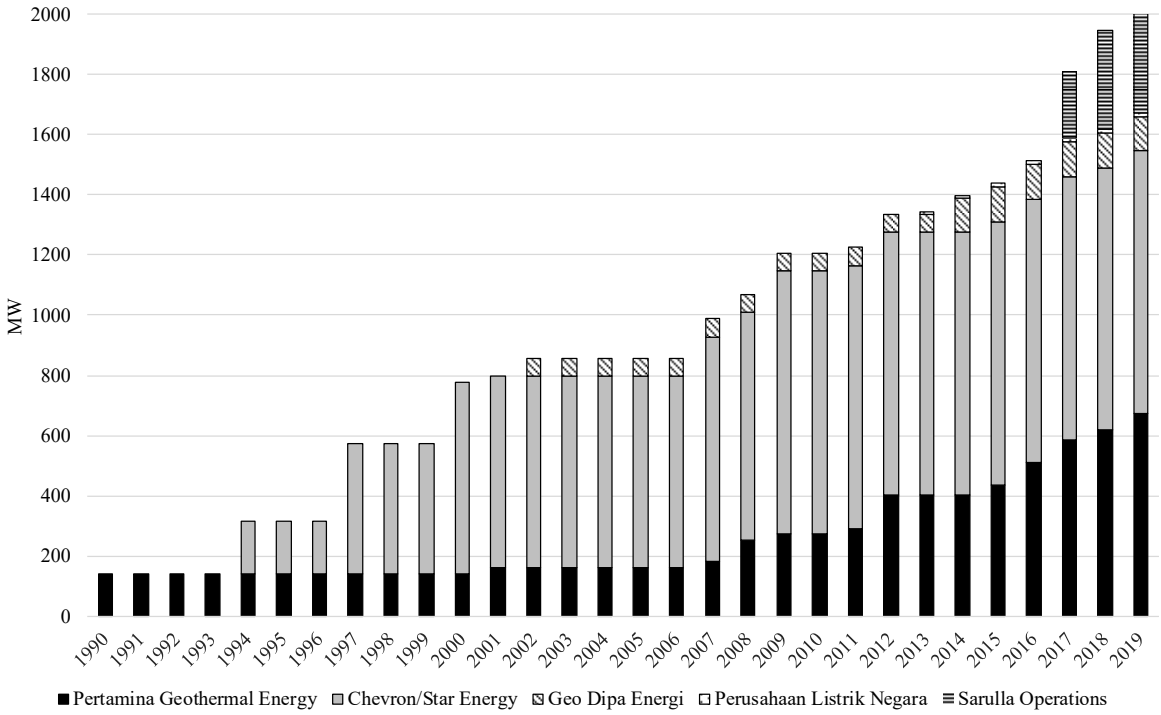


FIGURE 3: Annual increments of installed geothermal capacity in Indonesia

4.4 Long term development plan

The Government of Indonesia made efforts to satisfy domestic energy demands by establishing a National Energy Policy in 2014 which is regulated in Presidential Decree No. 79. It mandates that energy resources are prioritized for national development. To ensure this, the Government has set a number of targets which include the increase of renewable energy including geothermal energy to 23% in 2025 and to 31% in 2050.

The electricity guideline is in line with the commitment of the Government of Indonesia made at the 21st Conference of the Parties (COP) in Paris in 2015. The ratification of the Paris Agreement was validated into Law No. 16 of 2016, aiming at the reduction of CO_2 gas emission by 29% in the year 2030. Here, it is planned that utilization of geothermal energy for power generation will contribute 7.2 GW in 2025 and 9.3 GW in 2030. The 7.2 GW development plan can be seen in Table 5.

TABLE 5: Geothermal development road map 2019 to 2025 (MEMR, 2019)

	Status 2018	**Development plan (MW)**							**Total**
		2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	
Additional capacities (MW)	1,948.5	185	145	118	380	310	385	3,771	7,242
Investment (MUSD)	7,794	740	580	470	1,520	1,240	1,540	15,084	28,968
Manpower utilization (people)	5,846	555	435	353	1,140	930	1,155	11,313	21,726
Oil equivalency (kilo BOE/Year)	8,605.2	846.0	663.1	537.3	1,737.8	1,417.6	1,760.6	17,245.3	32,813.1
CO_2 reduction (tons×10^3)	11,979.4	1,177.8	923.1	748	2,419.2	1,973.5	2,451	24,007.4	45,679.5

4.5 Enterprising mechanisms and efforts

Geothermal enterprising in Indonesia can be divided into several schemes (for detail see Appendix II, Table 3):

1. Prior to the issuance of Geothermal Law No. 27 of 2003, a concession authority (adhered by PGE and Geo Dipa Energi) and Joint Operation Contracts (JOCs) allowed PGE to cooperate commercially with the private sector.
2. With the issuance of Geothermal Law No. 21 of 2014, the Geothermal Law No. 27 of 2003 was replaced. This enterprising involved several schemes, such as:
   a. GBP, mostly for private companies;
   b. Ministerial assignment to an SOE; and
   c. PSAE, as described in Section 4.2.

The issuance of the Geothermal Laws No. 27 in 2003, and No. 21 in 2014 has not led to the expected increase in successful GWA tenders. From 2008 to 2017, only 22 GWA have been successfully tendered. Of these, only 5 projects have completed the exploration stage with feasibility studies conducted. To fill this gap, the MEMR has initiated several efforts to accelerate geothermal development, including:

1. Emphasis on geothermal development in the east through attractive electricity prices;
2. Assignment to SOEs;
3. Deregulations of regional and centralized permits required to conduct geothermal enterprising;
4. Preliminary survey assignments and exploration; and
5. Geothermal funds which enable Independent Power Producers to have access to low-interest funds for geothermal projects.

5. EVALUATION OF GEOTHERMAL PROJECTS IN INDONESIA AND WORLDWIDE

5.1 Exploration strategies

Project execution strategies define a company's approach to handling available opportunities, optimise resources (funds, expertise), and avoid high risk to reach desired deliverables and goals. Project design includes the overall architecture of the project and should capture the available resources, funds, stakeholder objectives, expected benefits, risks and opportunity, priorities and urgency (IPMA, 2015). In geothermal development, upstream and exploration risks are considered high due to uncertainty of the projects. An uncertain geothermal resource that has been identified by a reconnaissance survey must be proven before a company considers field development and construction. Resource and project

development options must be technically achievable, economically feasible and environmentally acceptable.

In this research, we evaluate 5 geothermal projects where the exploration phase has been completed, to obtain information regarding their exploration strategies or approaches during the early stages. The exploration strategies include how each company managed their resources with the constraint to reduce uncertainty and to prove that exploitation of the geothermal resource is economical. The strategies are described and evaluated by the following criteria:

1. Geoscientific methods;
2. Well targeting and well siting;
3. Land clearance and infrastructure; and
4. Exploration drilling scheme (number of well pads, number of wells, and drilling contract).

This will provide qualitative and quantitative information regarding the confidence level of geoscientific information, strength and broadness of organizational structure, funds, and development opportunities to achieve the desirable project benefit/income. A summary and evaluation of each strategy which was utilized by each company is shown in in Table 6.

The approach chosen to conclude the existence of economic geothermal resources varies for each company. The reasoning for this approach is mainly related to the confidence level of the geothermal resource information obtained from preliminary studies such as temperature, permeability and area, project size, funding and capability of the organizational structure involved in the completion of the feasibility assessment of the geothermal project. The rationale premise of each strategy in each project can be seen in Table 7.

Project 1

In this project a cautious exploration strategy was used due to the small size of the project and possibly also due to little demand. The company also applied cheaper, nevertheless effective, geoscientific methods as CSAMT to locate the possible reservoir and to identify the permeable zone. CSAMT cannot provide information below 1-2 km depth (Grandis and Sumintadireja, 2012). Project 1 relies mostly on data that was provided by the Geological Agency, such as regional gravity and a temperature gradient well. The company estimated the size of the resource by using power density after completing the preliminary survey and volumetric measurements.

Due to the small size of the project, the company attempted to minimise the risk by adopting a small project organisational structure during the exploration stage. The project developer is a national/local investing company which may also be a reason for the cautious approach. However, the result of the exploration proved to be successful and only 2 wells were needed (1 well for production and the other for reinjection). The first production well provides energy to support a generation unit producing 4-5 MW. Project 1 employed a fully integrated project management (IPM) contractor for drilling. A full IPM drilling contract simplifies multiple drilling service contracts into one main contract and is generally used when geothermal companies have limited organisational capability for preparing and executing the drilling operations. This may result in higher unit cost (USD/m) but nonetheless, this type of contract is favourable for a small number of wells, less experienced personnel and smaller drilling organisation. Success ratio of exploration drilling in project 1 was 50%.

Project 2

In Project 2 a progressive and rapid exploration strategy was adopted, particularly during the exploration drilling. The extensive geoscientific survey involved remote sensing, detailed MT measurements, gravity measurements, and a CO_2 flux survey to identify resources. MT measurements are effective to identify subsurface targets down to 4-5 km depth (Grandis and Sumintadireja, 2012). Volumetric calculation is performed to estimate the resource at the end of the geoscientific survey. Exploration drilling did not start until a new investor joined the company in 2016. Project 2 has opted for a bundling

TABLE 6: Description of exploration strategies in 5 geothermal projects in Indonesia

Project	Exploration methods (geoscientific and resource estimation)	Well targeting and well siting	Land clearance and infrastructure design	Exploration drilling scheme
1	– Geological surveys (volcano stratigraphy, petrophysics, dating, geological hazard) – Geochemical sampling and temperature estimation from hot springs and fumaroles using geothermometers. – Geophysical controlled-source audio-frequency Magnetotellurics (CSAMT) with 100 m spacing to compare to earlier DC-Schlumberger surveys, gravity – Temperature gradient references based on government temperature gradient well – Resource estimation: power density of 13 MW/km^2 and volumetric calculation	– Geophysics, CSAMT measurements, indicating top of reservoir (ToR) at depths of 700-1200 m. – Avoiding high hazard/ vulnerability zones based on geotechnical map.	– Exploration drilling located in protected forest. – Infrastructure cost for one well pad (2.3 ha) and local access road.	– Utilize fully integrated Project Management contract. – Two directional wells.
2	– Light Detection and Ranging (LIDAR DTM), satellite imagery, GIS mapping system. – Geological mapping, structural mapping, geochemical sampling of gas and water. – Temperature estimation through samples from springs and fumaroles, using geothermometers, soil gas CO_2 flux survey. – Geophysics (200 Magnetotelluric/MT stations for 3D inversion, 506 gravity stations). – Resource estimation using volumetric calculation.	– LIDAR to delineate faults. – Fluid chemistry from previous wells. – Structural mapping and geoscientific survey.	– Exploration drilling outside forestry area. – Infrastructure cost for 5 well pads, access road, and public road improvement.	– Bundling contract on 10 directional wells. – Two drill rigs, 2 well pads (other 3 well pads drilled during development).
3	– Geological mapping, fault mapping. – Geochemical sampling from springs and fumaroles, temperature estimation using geothermometers. – Geophysical survey (131 MT stations, spacing 400 m), microearthquake monitoring (MEQ). – Resource estimation: volumetric and numerical modelling	– LIDAR. – Indication of ToR at 900-1300 m depth. – Structure and target identification from 3D MT section. – 3D well design (PETREL).	– Exploration drilling outside forestry area. – Infrastructure cost for 5 well pads, access road, and public road improvement.	– Direct contract for 6 directional wells. – One drill rig, 5 well pads.
4	– Geological mapping, fault mapping. – Geochemical sampling from springs and fumaroles, temperature estimation using geothermometers. – Geophysical survey: 90 MT stations, 3D inversion (2-3 km spacing in 2008), microearthquakes (MEQ) recording with 18 seismometers. – Resource estimation: volumetric and numerical modelling.	– LIDAR – Indication of ToR at 1000 m depth. – Structure identification, comprehensive 3D MT sections and detailed geoscientific results.	– Exploration drilling inside protected forest. – Infrastructure cost for 3 well pads, access road, bridge, site office and site housing.	– Direct contract for 6 directional wells. – One drill rig, 3 well pads.
5	– LIDAR DTM, satellite imagery, GIS mapping system. – Geological mapping, structural mapping. – Geochemical sampling from springs and fumaroles, temperature estimation using geothermometers. – Geophysical survey (including 35 MT stations and 3D inversion interpretation. – Resource estimation using volumetric calculation.	– LIDAR to delineate faults. – Fluid chemistry results from previous wells. – Structural mapping and detailed geoscientific results.	– Exploration drilling outside forestry area. – Infrastructure cost incl. 2 well pads, access road, and public road improvement.	– Bundling contract for 5 directional wells. – One drill rig, 2 well pads.

TABLE 7: Reasoning for exploration strategy

Project	Reasoning for exploration strategy
1	Small development capacity (< 10 MW); National exploration expertise; Shallow drilling target; Small exploration organization; Funded by local private company and investor.
2	Medium development capacity (45 and 4 × 50 MW); Small prospect area; Mixture of national and international exploration expertise; Deep and extensive exploration area and drilling target; Medium to large exploration organization (organic manpower 49 peoples); Funded 95% by foreign company & investor, changes of investor during exploration halted process; International & national contractors for exploration & drilling, local one for construction.
3	Large development capacity (1st phase 80 MW); Medium prospect area; Mixture of national and international exploration expertise; Deep and extensive exploration area and drilling target; Medium to large exploration organization (organic manpower 88 peoples); Funded 84% by foreign company and investor, foreign investor entered during exploration; International and national contractors for exploration, national contractor for drilling, and foreign contractor for construction.
4	Large development capacity (1st phase 86 MW); Large prospect area; Mixture of national and international exploration expertise; Deep and extensive exploration area and drilling target; Medium to large exploration organization (organic manpower 89 peoples); Funded 70% by foreign company and investor, foreign investor entered during exploration; International and national contractor for exploration, national contractor for drilling, and foreign contractor for construction.
5	Medium development capacity (6 × 5 MW); Small prospect area; Mixture of national and international exploration expertise; Deep drilling target; Small exploration organization (organic manpower 10 peoples); Funded 95% by foreign company and investor; Changes of investor during exploration halted the process; International and national contractor for exploration and drilling, local contractor for construction.

drilling contract to optimise drilling costs while maintaining control over the drilling activities. Bundled services is a modification of discrete/single and semi-IPM contracts to less than 13-20 contracts. The project was conducted by involving a foreign investor as a major stakeholder who sees large development capacity as an opportunity. The project utilizes both international and national contractors for exploration, construction and drilling.

Part of the exploration phase was the drilling of 10 exploration wells to deep and extensive drilling targets. Exploration drilling was conducted from only 2 discovery well pads. Due to changes in phase development, at least 7 wells were drilled from the second pad for the purpose of proving the resource, appraise unit 1 development and to increase steam availability for production at the same time. The success ratio of exploration drilling in project 2 was 60%.

Project 3
In project 3, the developer has a high degree of confidence in the geothermal resources, based on local and international peer reviewed studies. Multiple assessments and various methods were applied to increase the confidence level. This project utilised MT measurements to identify the resource and monitoring of passive seismicity (MEQ) with the aim to identify zones of permeability. Volumetric assessment and reservoir modelling were conducted at the end of the exploration stage to estimate the size of the resource and to provide baseline information for the development at same time.

Six exploration wells were drilled from 5 well pads to obtain good lateral distribution. All wells are large diameter wells and are designed not only to provide information on the resource but also to serve as production wells. The drilling strategy was inside-out, which means that after the resource has been proven at the beginning of the exploration drilling, the next well is located outside the reservoir to possibly obtain a different productive zone while delineating the reservoir boundaries. Project 3 uses a direct contract strategy in procuring drilling services due its larger project organisation, big number of wells and to reduce drilling cost of the large hole wells. Success ratio of exploration drilling in project 3 was 33%.

Project 4
Project 4 has similar exploration and development strategy as project 3. Multiple assessments and various methods have been applied to increase the confidence level. MT measurements were used to identify the resource and passive seismicity (MEQ) to identify zones of high permeability. Volumetric assessment and reservoir modelling were conducted at the end of exploration stage to estimate the size of the resource and to provide baseline information for development.

For project 4, the exploration strategy was outside-in, mainly due to infrastructural limitations since the project is located in a very steep terrain that requires stepwise civil construction. The most favourable exploration well pads are located far from road access. Project 4 used a direct contract strategy due to the large project organisation, high number of wells to reduce drilling costs of large diameter wells, and to ensure experienced personnel for the drilling while maintaining full control of drilling at the same time. Success ratio of exploration drilling in project 4 is 67%.

Projects 5
This project faced several constraints during the exploration stage. Change of ownership, local resistance, proximity to national park and funding limitations were an issue since the project was started. The change of ownership in 2017 revived the project. MT was used to visualise the resource and volumetric estimation was carried out to assess the resource capacity at the end of the exploration stage.

Exploration drilling started in 2017 when 5 exploration wells were drilled from a single pad, using a bundled drilling contract to reduce cost while maintaining control of the activities. The company used a small project organisation considering the size of the project. One of the main drivers of this project was the attractive power price. Success ratio of exploration drilling in project 5 is 40%.

5.2 Exploration results

Exploration strategy refers not only to the organisational approach used to obtain resource information throughout the project's lifecycle but also depends on the quality of the resource (temperature and dimension). The results of a geoscientific survey provide the basis for exploration and appraisal drilling. The exploration results from each project are described in Table 8. Maximum reservoir temperatures range between 256 and 300°C, reservoir depths range between 800 and 2500 m and the average capacity of successful wells (more than 2 MW) ranges from of 2 to 20 MW. Most projects opted to conduct exploration drilling by using 1-5 well pads to drill 2-10 exploration wells.

TABLE 8: Exploration results of the 5 Indonesian projects

Project	Prospect area (km^2)	Estimated temp. (°C)	Well pads	No. of expl. wells	Well depths (m)	Max. well temp. (°C)	Est. reservoir depth (m)	Steam flow (kg/s)	Well output (MW)	Est. res. (MW) - P90	Power density (MW/km)
1	1.2 - 2.9	250	1	2	1300	260	1100 - 1300	8.3	5	36	30.0
2	13 - 31	260 - 320	2	10	984 - 2593	290	800 - 1700	5.7 - 39.2	3 - 18	90	6.9
3	4 - 16	270 - 350	5	6	1570 - 2470	300	1100 - 2500	17 - 40	7 - 20	60	15.0
4	9 - 44	255	3	6	2248 - 2723	288	1400 - 2110	2 - 32.7	2 - 18	137	15.2
5	3 - 5	248 - 274	1	5	1925 - 2505	256	1065 - 1390	1.6 - 13	1.5 - 4.6	19	6.3

Resource size estimation for the projects varies from 19 to 137 MW with P90 probability. Wilmarth and Stimac (2015) suggest the use of power density for the first order capacity estimation which can provide a reasonable value but might vary as a function of resource type and temperature. In this study, power density (MW/km^2) is calculated considering P90 reservoir capacity (MW) and prospect areas (km^2). The power density estimated following that approach is in the range of 6 to 15 MW/km^2 for 4 out of 5 projects. But Project 1 has the very high power density of 30 MW/km^2 due to the small prospect area. The result is in good agreement with a study by Grant and Bixley (2011) which suggested general power density estimates of 10-15 MW/km^2. The distribution of power density for the 5 projects, together with other project in Indonesia and selected geothermal fields worldwide is shown in Figure 4.

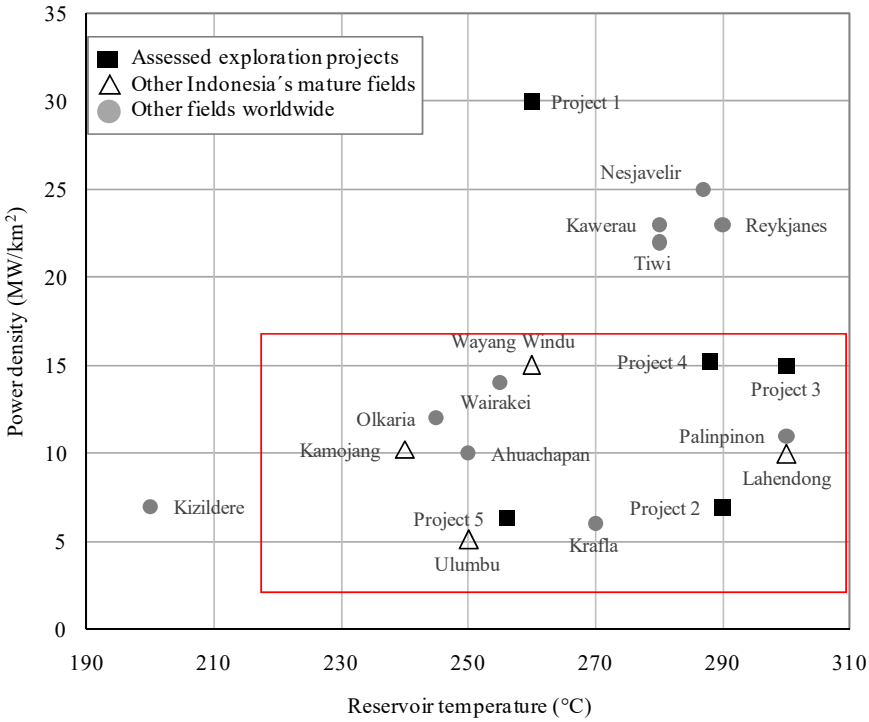


FIGURE 4: Power density distribution of 5 projects (modified from Grant and Bixley, 2011; and Wilmarth and Stimac, 2015)

5.3 Exploration cost

The exploration cost depends on the chosen exploration strategy and the way that the exploration has been executed and optimised. The exploration strategy is not static but might require correction and adjustment throughout the exploration stage to adapt to certain environments or conditions. Thus, the cost of exploration can differ significantly from the cost estimation made at the early stage of initial project planning. Therefore, it is unlikely that a different geothermal company which operates in a different geothermal area in a different project environment utilising a similar exploration strategy will end with a similar exploration cost and completion time. Each of the 5 projects started and completed their exploration stage at different times. To compare them, the exploration cost needs to be normalised, using an index.

This study uses the US producer price index (US PPI) which is calculated annually by the Bureau of Labor Statistics (2019). The US PPI measures average changes in price received by domestic producers for their goods and services. To compare exploration drilling cost which depends highly on the international oil and gas market, the average of US PPI industry data for oil and gas field machinery and equipment is used. To compare the total project cost consisting of drilling cost and the cost for the turbine and the generator, the average of US PPI industry data for oil and gas field machinery and equipment in conjunction with US PPI industry data for turbine and turbine generator set units is used. A gradual increase of both oil-gas and turbine-generator indices could be observed from 2000 to 2019 (Figure 5). Therefore, the geothermal exploration cost and total project cost are 68 and 58% higher in 2019 than in 2000.

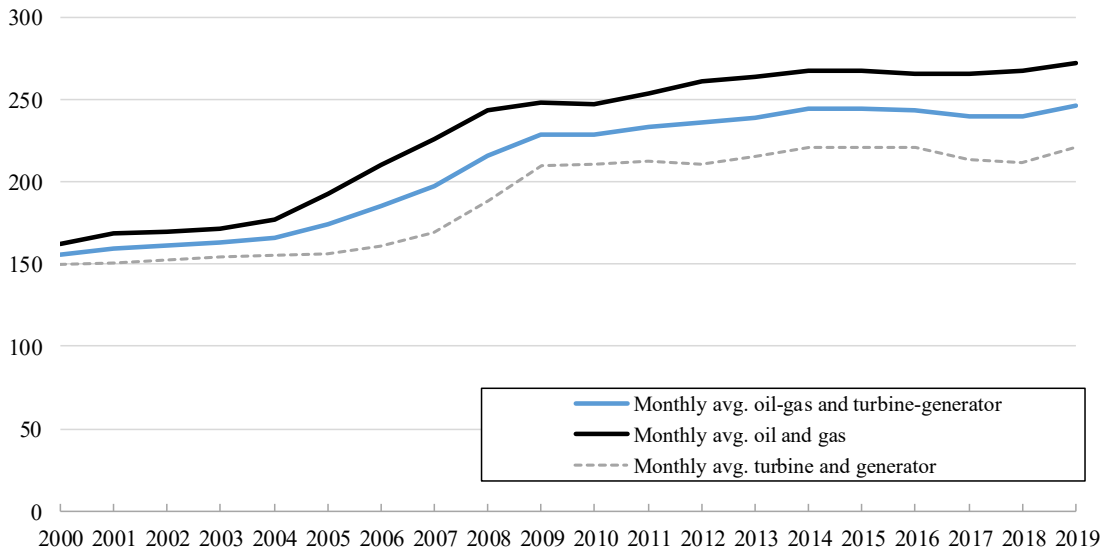


FIGURE 5: Annual US PPI indices used for normalising exploration and project cost

Exploration costs are mainly composed of the geoscientific survey, land acquisition, civil construction, exploration (and appraisal) drilling, well testing, annual overhead cost and field and office administration cost. A comparison of cost components of the five different projects is presented in Table 9. It shows that exploration cost in Indonesia per MW development capacity is in the range of 0.6-2 million USD.

TABLE 9: Exploration cost for the five Indonesian projects

Project	Geoscientif. surveys (MUSD)	Land acquisition & civil con-struction (MUSD)	Explorat. drilling and well testing (MUSD)	Overhead & adminis-tration (MUSD)	Total exploration cost (MUSD)	Exploration cost per MW (MUSD/ MW)	Drilling to explora-tion cost ratio (%)
1	0.3	1.7	13.3	1.0	16.4	1.6	81
2	0.8	18.1	53.1	76.8	148.7	0.6	36
3	7.0	44.0	61.0	18.0	130.0	1.6	47
4	6.0	88.0	58.0	21.0	173.0	2.0	34
5	0.2	2.8	34.6	11.2	47.8	1.6	70

Projects 1, 2 and 5 exhibit exploration costs of less than 1 million USD prior to exploration drilling, whereas projects 3 and 4 have high costs due to the number of geoscientific studies, peer reviewing, and foreign expertise involvement. Exploration drilling accounts for 34-81% of the total exploration cost. Projects 1 and 5 exhibit the highest ratio due to low cost of infrastructure and administration. Projects 3 and 4 allocate 33 and 51% of the exploration cost for civil works, due to low quality of existing infrastructure prior to exploration drilling, the number of constructed well pads and road length.

The ratio of exploration costs to total planned project cost is in the range of 15-28% for projects 2-5 (Table 10). Project 1 has a ratio of 40% due to the small prospect area that needed to be explored and the project's small capacity (10 MW) which leads to low total project cost.

TABLE 10: Exploration cost for the five Indonesian projects compared to the total project cost

Project	Project size (MW)	Total exploration cost (MUSD)	Total planned project cost (MUSD)	Ratio of exploration cost out of total project cost (%)
1	10	16.4	41	40
2	45 and 4×50	148.7	984	15
3	80	130	469	28
4	86	173	618	28
5	30	47.8	216	22

Exploration drilling cost average of the 5 projects is USD 7.6 million. Project 2 has the lowest exploration cost per MW, while the average exploration cost per MW is 4.1 million USD for all the projects. Exploration cost per well, cost per well output and exploration drilling success ratio are listed in Table 11.

TABLE 11: Exploration drilling cost per well and exploration cost per MW of well output for the five Indonesian projects

Project	Well pads	Number of exploration wells	Number of successful wells (≥ 2 MW)	Exploration drilling success ratio (%)	Steam available at well head (MW)	Exploration drilling cost per well (MUSD/well)	Exploration cost per well output (MUSD/MW)
1	1	2	1	50	4	6.7	3.8
2	2	10	6	60	54	5.1	2.8
3	5	6	2	33	20	10.2	4.8
4	3	6	4	67	34	9.7	5.0
5	1	5	2	40	11.7	6.46	4.1

Exploration cost distribution varies for each project. It depends on several factors such as the size of the project, amount of time to obtain the PPA, funding, development capacity, permission complexity, and infrastructure challenges. In most projects, up to 40% of the total project cost is spent in the early phase to secure permissions, acquire land, minimise risk of development, and develop confidence about the resource prior to development. In most cases, project commercial bankability is assessed after appraisal drilling has been carried out. However, in accordance with Geothermal Law No. 21 of 2014, all project developers must complete exploration and submit a feasibility study prior to transitioning to the development phase. Therefore, project bankability of the 5 projects is assessed after the exploration phase is completed (Figure 6).

According to Art. 31 of Geothermal Law No. 21 of 2014, all developers must complete the exploration phase within 7 years. Figure 7 shows that in projects 2, 3 and 4 the first expenses were made during the first or second year after the issuing of the geothermal permits. The cost for projects 3 and 4 were high during years 3-5 due to civil construction activity and exploration drilling. In project 2, spending was increased during years 6 and 7, when 10 wells were drilled within a period of approximately 1 year. Projects 1 and 5 needed project extensions due to difficulties in obtaining water intake permits and change of investor, respectively. Therefore, exploration activities show significant increase during the last 2 years of exploration.

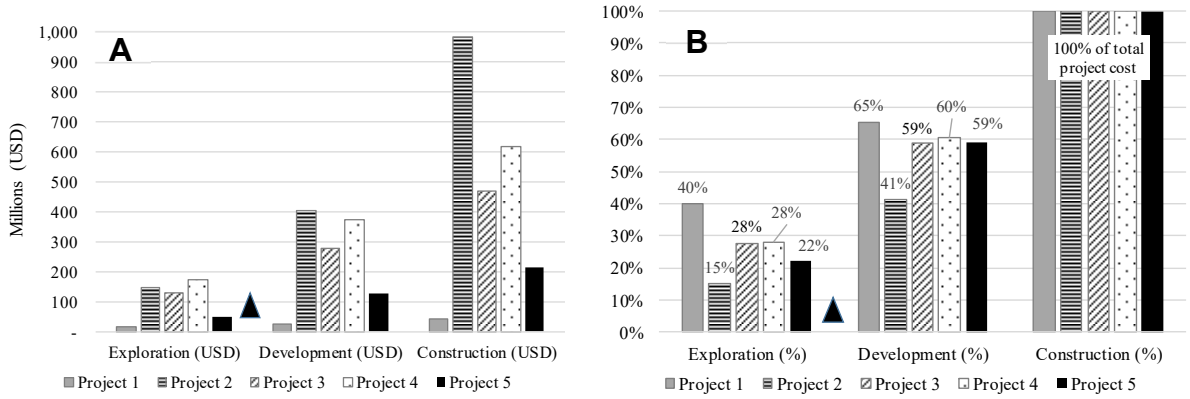


FIGURE 6: Comparison of a) Cumulative cost; and b) Cumulative percentage at end of each phase, for five Indonesian projects; black triangle indicates time when bankability of projects is assessed

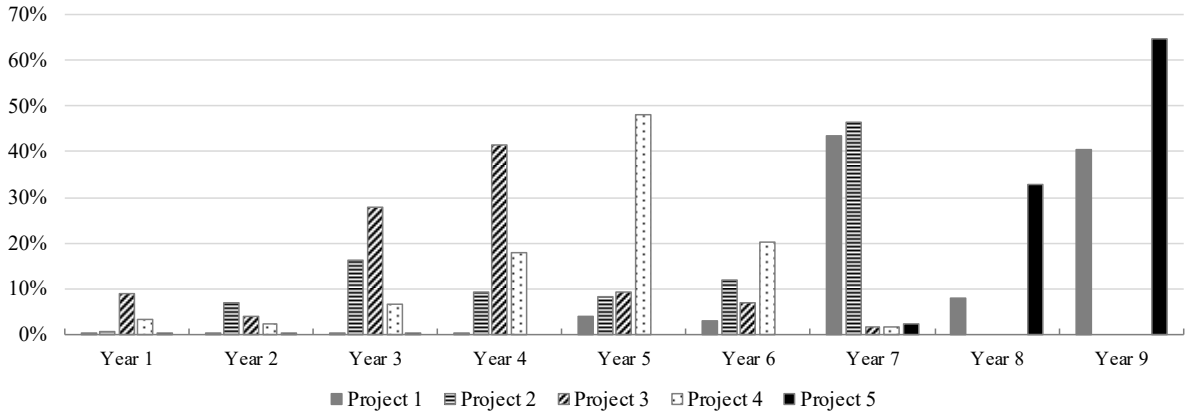


FIGURE 7: Annual project cost distribution of the five Indonesian projects

5.4 Worldwide comparison

A worldwide cost comparison is carried out in this study to obtain a general picture of the magnitude of exploration costs with regard to other leading geothermal countries. Unit cost/MW is used to normalise cost and to consider development capacity and project size. The comparison of exploration cost is presented in Figure 8. Projects 1, 3, 4, and 5 have significantly higher exploration cost, or 0.6-2 million USD/MW, compared to other countries where the cost is 0.2-0.8 million USD/MW. This is possibly due to the fact that the 5 projects in Indonesia are all located in green fields where no exploration drilling had been conducted previously. Another factor that might have an impact on the exploration cost is the drilling depth and reservoir depth which in projects 3 and 4 is down to 2500 and 2700 m depth, respectively. This is common in areas of high mountains, like in Indonesia with drilling equipment in most cases rented on a daily rate. In Iceland, exploration cost is lower possibly due to mature field (brown field) development (Iceland-1) and low drilling costs that are optimised by the use of hybrid contracts (Iceland-2). The Philippines, however, have a similarity with Indonesia in terms of drilling depth, but the assessment is conducted in a brown field which has been exploited since 1993.

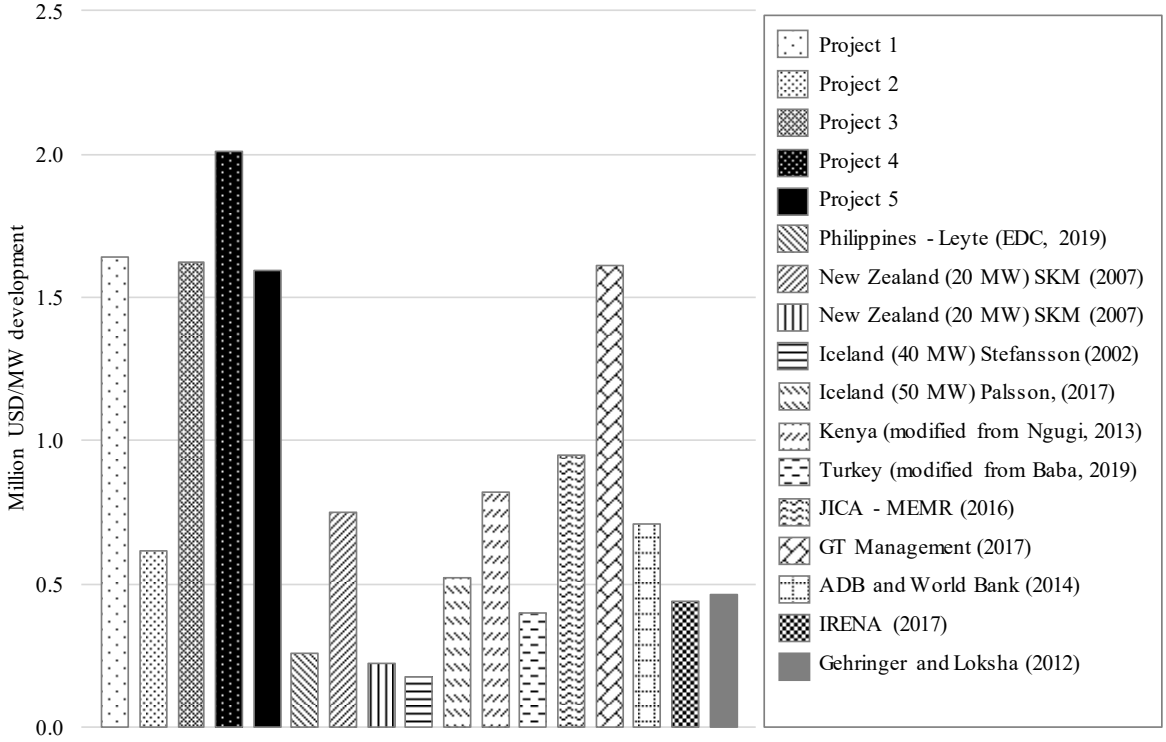


FIGURE 8: Worldwide comparison of geothermal exploration cost per MW

5.4.1 Turkey

Geoscientific exploration in Turkey is conducted in 6-7 months while exploration drilling usually takes place within 1 year. Most Turkish geothermal companies drill 1-3 exploration wells and the depth of most reservoirs ranges from 100 to 1000 m. However, in several cases, exploration wells may be as deep as 3000 m (depth depending on geological setting). Drilling costs in Turkish fields range from 0.5 to 1 million USD. The reason for the low drilling cost is not clear, but a possible explanation is that some companies own drilling rigs or are a holding company of a service company (Alper Baba, Izmir Institute of Energy, pers. comm., September 2019).

Since exploration drilling costs are a large portion of the exploration cost, it can be concluded that lower geothermal exploration cost in Turkey is due to low cost of drilling. This is confirmed by Gul and Aslanoglu (2018) which described that standard well cost in Turkey is in the range of 3.3 million USD for a 4500 m deep well, which is cheap compared to other countries. This is due to the following reasons:

1. Lower operating cost of drilling equipment, third party services and labour;
2. High-grade casing not required because of the absence of overbalance conditions; and
3. Daily rates for drilling equipment follow oil trend which leads to a competitive market.

5.4.2 Philippines

The Energy Development Company (EDC) is the most active company in geothermal exploration in the Philippines and conducts exploration that generally takes 5 to 7 years. Geoscientific exploration costs vary from 0.8 to 1 million USD. For exploration drilling, the EDC typically requires at least 2 well pads and at least 3 exploration wells which are normally 2500 to 3000 m deep. Exploration drilling costs are typically 8-10 million USD per well (Raymundo Jarque, EDC, pers. comm., August 2019).

In the Philippines, geothermal prospects and fields are mostly located in mountainous areas which may cause the drilling cost to be relatively high. Exploration costs and total project cost per MW in EDC

fields, based on the authors evaluation, is fairly low. The Philippines field Leyte, which is used as an example here is considered to be a brown field project. Exploration costs are approx. 0.25 million USD/MW and the total project cost is about 2 million USD/MW. The Leyte field is considered a highly developed and mature field and the upstream risk has been mapped and minimized.

5.4.3 Kenya

In Kenya exploration surveys which include a detailed surface investigation and desk interpretation may cost up to 2 million USD. The cost of infrastructure is influenced by the remoteness of the location and availability of drilling water. Generally, 3-4 exploration wells are required, one as a discovery well and two or three confirmation wells. Prior to entering bankability stage, 6-9 appraisal wells are drilled to provide the basis for development. Drilling wells in Kenya using locally owned rigs normally cost about 3.5 million USD and about 6.5 million USD using hired rigs. Then a feasibility study which would cost about 2 million USD is carried out including reservoir simulation and preliminary design of the power plant (Ngugi, 2013).

An estimate based on use of 4 exploration wells and 8 appraisal wells for the development of a 100 MW plant indicates that cost of exploration in Kenya is approximately 0.8 million USD/MW. This is assuming that the drilling success rate during exploration and appraisal is 50 and 75%, respectively. Using this assumption, the total project cost is about 3.4 million USD/MW.

5.4.4 Iceland

During exploration stage, when the project the risk is highest, drilling costs dominate the project costs (Pálsson, 2017a). Typically, projects in Iceland require 1-4 wells to confirm the existence of the geothermal system, to measure temperature and pressure and to analyse fluid properties (Pálsson, 2017b). Generally, drilling costs are a very significant proportion of the overall the project costs, or about 20-50%. Exploration costs per MW are approximately 0.5 million USD/MW and total project cost is about 4 million USD/MW.

Drilling costs in Iceland are typically below 4 million USD per well, which is ensured by the involvement of an integrated hybrid-type drilling contract. Separately from integrated drilling services or conventional drilling contracts which typically involve a daily rental, a hybrid-type contract allows the developer to compensate the drilling contractor with a mix of lump sum unit price for mobilisation, meterage for drilling, casing run and cementing and daily rate for logging or when stuck over a long period (Pálsson, 2017b).

When conducting exploration, most Icelandic geothermal companies consider the following aspects: size of projects, energy price (expected profit), demand, vicinity to the grid and environmental issues. Geothermal projects in Iceland normally require that the steam supply is at least 50% in wellhead prior to deciding to progress to the construction stage. Exploration cost for a 45 MW project in Iceland accounted for 17% of the total project cost (Bjarni Pálsson, Landsvirkjun, pers. comm., September 2019).

5.4.5 New Zealand

The geothermal industry in New Zealand is influenced by extensive historical involvement from the Government (Crown) in the exploration and resource assessment. This reduces the risks and costs for developing green fields in New Zealand. According to Barnett and Quinlivan (2009), geothermal exploration cost of a green field in New Zealand for a 20 MW and a 50 MW project are 0.75 and 0.22 million USD/MW, respectively. Total project costs are in the magnitude of 4.4 million and 2.2 million USD, respectively. This assessment is carried out considering a drilling success ratio of 70% during exploration, resulting in a fairly low total drilling cost for a given project size of about 5.2 million USD per well.

5.4.6 Summary of worldwide comparison

Given the significant proportion of exploration drilling in exploration cost, a comparison of average drilling costs, depth and type of well in several geothermal countries is presented in Table 12 and illustrated in Figure 9.

TABLE 12: Country comparison of average drilling costs, depth and type of well

Country	Year	Drilling cost with US PPI 2019 (MUSD)	Av. depth	Av. no. of days	Unit cost (USD/m)	Size of well	Reference
Turkey	2018	3.4	4500	45	752	Standard	Gul and Aslanoglu, 2018
Philippine	2019	9.0	2500	-	3,600	Large	Jarque, pers. comm., 2019
Kenya 1	2013	6.7	3200	-	2,093	Large	Ngugi, 2013
Kenya 2	2013	6.2	3000	63	2,076	Large	Kipsang, 2015
Iceland 1	2002	2.4	1500	-	1,602	Standard	Stefánsson, 2002
Iceland 2	2012	4.9	2175	43.5	2,235	Large	Thórhallsson and Sveinbjörnsson, 2012
Iceland 3	2014	4.4	2235	45	1,961	Large	Sveinbjörnsson and Thórhallsson, 2014
Iceland 4	2017	4.1	2500	45	1,638	Standard	Pálsson, 2017a and b
N. Zealand 1	2006	4.2	2600	-	1,621	Standard	Hole, 2006
N. Zealand 2	2007	5.2	2500	-	2,506	Large	Barnett and Quinlivan, 2009
N. Zealand 3	2010	3.7	2306	33	1,610	Standard	Bush and Siega, 2010
N. Zealand 4	2010	7.3	2558	63	2,855	Large	Bush and Siega, 2010
Indonesia	2018	8.1	2000 - 2700	60	3,960	Large	Author's analysis

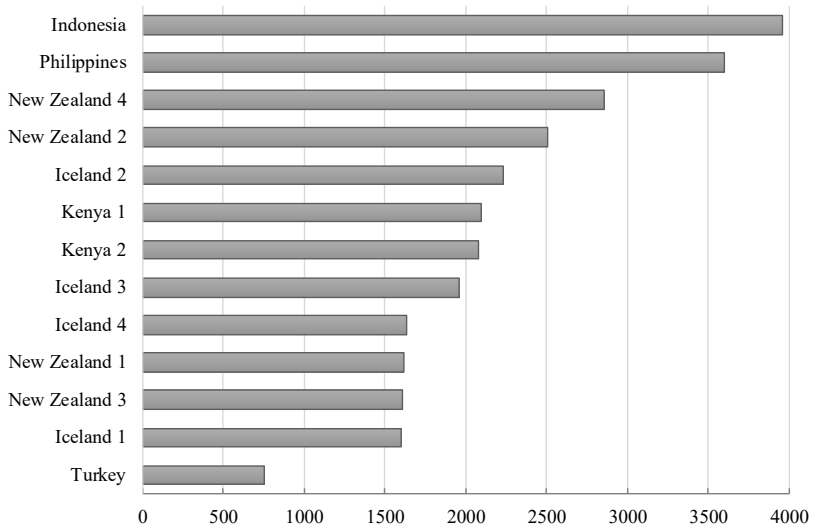


FIGURE 9: Drilling unit cost comparison (USD/m)

6. RESULTS AND DISCUSSIONS

6.1 Key findings

Key findings of this study are categorised and structured in Table 13.

TABLE 13: Key findings of exploration strategy, result and cost of 5 geothermal fields in Indonesia

Key findings	Remarks
Driving elements influencing exploration strategy	1. Size of project (area, MW, and cost), 2. Corporate resources (process, equipment, people, expertise, experience), 3. Project and corporate organisation structure and complexity, 4. Access to funds, 5. Magnitude of company and foreign investor involvement, 6. Associated project risk, 7. Exploration area size, 8. Confidence level of geothermal resource availability (expected temperature and size/dimension), 9. Development-forward orientation.
Overall project strategy implemented in the 5 assessed projects	1. Project strategy influenced by low-scale development (< 20 MW) with small funding, small organization and fully cautious exploration approach due to nature of risks which are only endured by one company, as seen in project 1. 2. Project strategy based on medium- to large-scale development (> 20 MW). This includes large funding, large project organization, international shareholder involvement promoting a progressive approach, distributed project risks since more than one project is operated by the same holding company (project portfolio). This scheme is observed in projects 2, 3, 4 and 5.
Coverage of exploration strategy	1. Geoscientific methods: a. Precondition and methods applicability, b. Detail level of studies, 2. Number and distribution of wells, 3. Number and distribution of well pads, 4. Exploration drilling design (depth, well diameter, casing design, anticipated pressure and temperature), 5. Exploration drilling contract (material, equipment and cost), 6. Well sequence and contingency plan, 7. Well completion and testing, 8. Integrated subsurface data interpretation and evaluation, 9. Resource assessment methods.
Drilling activity and drilling success ratio	1. Number of wells range from 2 to 10. 2. Number of well pads range from 1 to 5. 3. Exploration well depths range from 984 to 2723 m. 4. Drilling duration mostly ranges from 35 to 65 days. 5. Drilling success ratios during exploration are 33-67%.
Exploration result	1. Reservoir temperature ranges from 256 to 300°C. 2. Reservoir depths range from 800 to 2500 m. 3. Power density for exploration field ranges from 6 to 15 MW/km^2. 4. Average exploration well output of 29 wells is 5 MW/well.
Exploration cost	1. Exploration drilling cost average is 7.6 million USD per well. 2. Exploration cost per MW development capacity is in the range of 0.6-2 million USD (all of these are green field projects). 3. Exploration cost is 15 to 40% of the total planned project cost.

Comparison between the 5 Indonesian projects to the projects in other countries:

1. Exploration cost per MW for the 5 Indonesian projects is in the range of 0.6 to 2 million USD, which is significantly higher. Gehringer and Loksha (2012) suggest the amount 0.3-0.8 million USD. Worldwide exploration costs are in the range of 0.2-0.8 million USD. This significant difference is possibly caused by the nature of the 5 projects in Indonesia which are greenfield projects where no exploration drilling had been conducted previously.
2. Total project cost per MW in the 5 Indonesian projects is in the range of 4-7.2 million USD which is also considerably higher than Gehringer and Loksha (2012) suggest. Their numbers are 2.8-5.5 million USD while the worldwide project costs are in the range 2.5-5 million USD/MW.

It is essential to plan an exploration strategy which considers multiple options as well as time and budget limitations. A suggested framework for an exploration strategy can be found in Appendix II, Table 4.

6.2 Main limiting factors for geothermal project developments in Indonesia

This study also formulated main factors that restrict geothermal development in Indonesia, as follows:

1. Limited access to remote prospects and inadequate infrastructure lead to higher infrastructure cost, up to 1 million USD per MW.
2. Expensive exploration drilling with average cost of 7.6 million USD per well is much higher than in the referenced countries. This is mainly due to mountainous area, limited access to the prospect, frequent drilling problems, and drilling services and equipment contracts.
3. Small-scale prospects are often located in isolated areas or islands.
4. Corporate funding/equity for exploration stage is often not readily in place to support completion of exploration.
5. Upstream risk is substantially high, specifically in areas that have not been drilled yet.
6. Geothermal power is not cost competitive with coal-fired and hydro generation, at least in the western part of Indonesia.

6.3 Recommendations for future developments of geothermal energy in Indonesia

Recommendations to accelerate geothermal exploration and hasten geothermal development in Indonesia are:

1. Encourage geothermal companies to conduct volumetric assessment in conjunction with numerical simulation to obtain more accurate estimates and to support development stage.
2. Increase Government supervision, in particular during exploration stage, to reduce time extension and minimise project cost overrun.
3. Introduce mixed drilling contract/hybrid-type (daily rate, meterage and lump sum) to exploration drilling market with the aim of reducing drilling costs.
4. Reduce upstream risk by accelerating Government participation in green field areas through Government drilling.
5. Encourage geothermal companies to mitigate strategic, operational and financial project risk by distributing risk through having more than 1 project.
6. Increase incentives schemes for geothermal exploration to ease costs during exploration.
7. Utilize upstream insurance scheme to address exploration drilling risks.
8. Intensify geothermal cluster-based development to cover isolated and small-scale prospects.

7. CONCLUSIONS

Results from this assessment indicate that geothermal exploration strategies and costs of 5 geothermal projects in Indonesia differ from each other. The exploration methods are quite different between projects but this is justified by the individual conditions.

Cost of exploration in Indonesia is high compared to other countries. Exploration cost in the 5 analysed projects ranges from 0.6 to 2 million USD/MW compared to 0.2 to 0.8 million USD/MW in the reference countries. This means that the exploration cost is 15-40% of the overall planned project cost and is the amount of expenditure required prior to deciding whether to develop the field. The reason for exploration cost being high in Indonesia is possibly the fact that the projects are still in the *green field* phase, site infrastructure for some projects is challenging (landscape and land use issues), and drilling costs are high (possibly due to geological condition, operational issues and drilling contracts).

The number of exploration wells in Indonesia, based on the 5 geothermal projects, ranges from 2 to 10, drilled from 1 to 5 well pads. Exploration drilling success ratio ranges from 33 to 67%. The power density of the 5 fields ranges from 6 to 15 MW/km^2 which is in good agreement with the worldwide energy density particularly during exploration. The average output acquired from 29 wells in 5 projects is 5 MW/well.

It is recommended to strengthen Government control, particularly during the exploration stage to ensure that developers comply with time limits, to ensure best practices and optimum use of funds which can lead to improved project economics. It is advised to introduce mixed contracts in exploration drilling and increase market competitiveness of drilling contractors using experience from other countries with the aim of reducing exploration cost. It is necessary to include additional incentives to reduce exploration expenditure and to create additional demand by intensifying cluster-based development with the aim to accelerate optimised geothermal exploration.

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APPENDIX I: Geothermal development framework (mod. from Gehringer and Loksha, 2012)

	Preliminary survey	Exploration survey	Exploration / test drilling	Project review and feasibility	Field development	Power plant construction and commissioning	Operation
Activities required	▪ Power market analysis (power purchase agreements/PPA) ▪ Other possibilities for geothermal utilization ▪ Infrastructure ▪ Regulation, political, environmental and social issue ▪ Required permitting ▪ Issues relating to political and financial stability ▪ Remote sensing or aerial survey data ▪ Information from available geoscientific data ▪ Information from previous explorations or wells ▪ Preliminary geoscientific survey	• Detailed geoscientific survey: ✓ Geology study (volcanostratigraphy, structural mapping, identification thermal features) ✓ Geochemistry (thermal features measurement, sampling, fluid geothermometry, soil sampling and gas flux) ✓ Geophysics (heat flow, gravity, resistivity, magneto telluric, passive seismic, temperature gradient and conductive heat flow) • Geotechnical study • Environmental study • Temperature gradient well • Conceptual model • Resource estimation • Pre-feasibility study	• Exploration infrastructure construction • 2-3 wells drilling • Well logging • Well testing • Refining of conceptual model • Determination of well productivity for production • Design for development well	• Location and design of development pads and other civil works • Development drilling targets and well design • Forecasts of reservoir performance • Power plant and transmission design • Project budget and revenue projections • PPA finalization • Environmental social assessment	• Infrastructure construction • Development drilling (production and reinjection) • Well logging • Well testing • Update of conceptual model • Update of reservoir model	• Engineering • Procurement • Construction • Commissioning	• Operation and maintenance • Well intervention • Make up well drilling • Annual inspection • Major overhaul
Time required	1 year	1-2 years	1 - 2 years	1 – 3 years	2 years	1 – 3 years	20 – 30 years
Costs required (USD/MW)	Author analysis : 30,000 – 90,000 ESMAP (2012) : 20,000 – 80,000		Author analysis : 1.5 – 2 million ESMAP (2012) : 0.32 – 0.8 million		Author analysis : 1.1 – 2.7 million ESMAP (2012) : 0.9 – 2 million	Author analysis : 1.4 – 3 million ESMAP (2012) : 1.5 – 2.5 million	Author analysis : 18 – 30 USD/KWh/yr ESMAP (2012) : 35 USD/KWh/yr
Project risk	High (100-95%)	High (95-90%)	High to moderate (90-50%)	Moderate (50 - 45%)	Moderate (45-35%)	Moderate-low (35-20%)	Low (10%)
Funding source	Government, grant, private equity	Government, grant, private equity	Private equity	Private equity	Commercial loan	Commercial loan	Commercial loan

APPENDX II: Information on geothermal fields in Indonesia and exploration strategy

TABLE 1: Exploration fields/prospect in Indonesia from 1920s to 2019,
(modif. & updated from Hochstein and Sudarman (2008) and Anna Yushartanti (pers. comm. 2019))

Phase	Preliminary survey, geoscientific exploration and or temperature gradient drilling	Exploration drilling or test drilling	Power plant commissioning and operation
1920 – 1970	Kamojang	-	-
1971 – 1980	Dieng, Darajat, Salak, Cisolok, Kaldera Danau Banten, Bedugul, Muaralaboh, Sungai Penuh/Semurup, Lahendong, Kotamobagu	Kamojang	-
1981 – 1995	**Jawa:** Ungaran, Wayang Windu, Wilis, Ijen, Patuha, Tangkuban Parahu, Telaga Bodas, Arjuno-Welirang, Cilayu, Gunung Endut, Lamongan, Muria, Slamet, Tampomas, Cibuni, Iyang Argopuro **Sumatera:** Seulawah Agam, Sibayak, Sorik Marapi, Sibual-buali (Silangkitang and Namora-i-Langit), Gunung Kembar, Pusukbukit, Muaralaboh, Sungai Penuh, Gunung Kunyit, Hululais, Lumut Balai, Suoh Sekincau, Ulubelu, Rajabasa, Gunung Talang, Margabayur, Graho Nyabu, Sungai Tenang, Danau Ranau and Way Ratai **Nusa Tenggara and Sulawesi:** Ulumbu, Tompaso	Darajat, Salak, Wayang Windu Lahendong, Ulumbu, Sibual-buali (Silang-kitang), Cibuni	Kamojang unit 1 1982, units 2 & 3 1987 Salak units 1 and 2 1994 Darajat unit 1 1994
1996 – 2000	Karaha Bodas, Sokoria, Mataloko, Ciater, Tulehu	Karaha Bodas, Patuha, Mataloko	Salak unit 3, 4, 5, 6 1997 Sibayak monoblock 1998 Wayang Windu 1 2000
2001 – 2010	**Geological Agency:** Pulau Pantar, Mangolo, Mamasa, Adonara, Roma, Bukapiting, Mataloko, Lesugolo, Adum, Sampolawa, Luwu Parara, Iyang Argopuro, Ujelewung, Atadei, Oka, Gunung Talang, Parang Tritis, Pulu, Suwawa-Pentadio, Waisano-Werang, Alor, Ile Ange-Ile Padung, Bukit Kili, Huu Daha, Marana, Danau Ranau, Bukapiting, Sokoria, Akesahu, Lopmio, Pincara, Sabang, Sipaholon, Suwawa, Pulau Buru, Songa Wayaua, Haruku, Dolok Marawa, Sangalamakale, Jaboi, Gunung Endut, Ulu Kuantan, Gunung Kembar, Sampuraga, Akelamo, Ciater, Bonjol, Sinjai, Hulu Badak, Cubadak, Tilamuta, Alue Long, Simbolon, Ulu Kuantan, Maseppe, Tambo, Ransiki, Pulau Seram, Poliwalimandar, Gunung Lawu, Limbong, Bittuang, Waisekat, Bonjol, Kandangan, Pasaman Barat, Sanggau, Tali Abu, Arjuno Welirang, Bora, Gunung Kapur, Kepahiang, Lainea, Lili, Tehoru, Telomoyo, Limbang **PSA holder:** Guci, Baturaden, Muaralaboh, Rajabasa, Rantau Dedap	Ulubelu, Lumut Balai, Kotamobagu, Tulehu	Dieng unit 1 2002 Lahendong unit 1 2001, unit 2 2007, unit 3 2009 Darajat unit 2 2007 Kamojang unit 4 2008 Sibayak units 1 & 2 Wayang Windu 2
2011 – 2018	**Geological Agency:** Nunukan, Posos, Pulau Wetar, Banda Baru, Ranang-Kasimbar, Pamacalan, Riso-kalimbua, Wai Selabung, Maranda, Sumani, Kampala, Maseppe, Laenia, Lili, Marana, Limbong, Kepahiang, Boalemo, Mamuju, Simisuh, Talu Tombang, Way Umpu, Kawende, Kadidia, Kitamani, Suwawa, Lompio, Bittuang, Bukit Kili, Laenia, Cubadak, Maranda, Wapsalit, Tamiang, Bitung, Manggarai Timur, Amfoang, Banda Baru, Kadidia, Cubadak, Sumani, Lemosusu-Sulili, Lokop, Talago Biru, Sulili Pinrang, Torire, Dua Saudara, Way umpu, Ampallas, Bukit Kili-Gunung Talang, Bittuang, Lainea, Simisuh, Kintamani, Mahakam, Luwuk-Banggai, Bone, Permis, Kadidia, Mapos, Kalawat, Pariangan, Malingping, Kaloi, Pohon Batum Way Selabung, Lili-Seporakki, Lili-Matangnga, Lainea, Dua Saudara, Sumani, Banda, Kampar-Kuantan Singingi, Tanjung Jabung Timur, Wasiano, Sajau, Pulau Pantar, Maritaing, Parogo, Diloniyohu, Pohon Batu, Dolok Marawa, Mapos, Sumani, Lompio, Amohola, Cubadak, Kadidi, Geragai, Buaran-Bumi Ayu, Banda Neira, Toro, Pincara, Pidie, Sekko-Rumpi, Lompo Batang, Toli-Toli, Pincurak, Surian, Gimpu, Barru, Nage, Gou Inelika, Gunung Sago, Alue Calong, Lompo Batang-Pencong, Lejja-Watan Soppeng, Tinigi-Lorent, Tanuhi, Bonjol, Ciremai, Papandayan, Maseppe, Kanan Dede	Hululais, Sungai Penuh, Muaralaboh, Rantau Dedap, Tangkuban Perahu, Sorik Marapi, Jaboi, Sokoria, Baturaden, Blawan Ijen	Lahendong unit 4 2011, units 5 & 6 2016 Ulubelu units 1 & 2 2012, unit 3 2016, unit 4 2017 Ulumbu units 1 & 2 2012, units 3 & 4 2014 Mataloko unit 1 2012 Patuha unit 1 2014 Kamojang unit 5 2016 Sarulla units 1 & 2 2017, unit 3 2018 Karaha unit 1 2018

Phase	Preliminary survey, geoscientific exploration and or temperature gradient drilling	Exploration drilling or test drilling	Power plant commissioning and operation
	GBP holder: Jailolo, Cisolok-Cisukarame, Tampomas, Muara Laboh, Rantau Dedap, Rajabasa, Jaboi, Blawan Ijen, Kaldera Danau Banten, Sokoria, Telaga Ngebel, Way Ratai, Gunung Lawu, Talang-Kili, Umbul Telomoyo, Arjuno Welirang, Atadei, Tangkuban Perahu, Songa Wayaua, Ungaran, Guci, Kepahiang, Seulawah Agam, Danau Ranau, Oka Ile Ange, Gunung Sirung **PSA holder:** Mataloko, Gunung Dua Saudara, Sembalun, Gunung Gede Pangrango, Gunung Wilis **PSAE holder:** Hamiding, Graho Nyabu, Sekincau Selatan, Simbolon Samosir, Tanjung Sakti, Huu Daha, Geurudong, Pentadio, Klabat, Bonjol, Lawang Malintang, Tandikat-Singgalang		

TABLE 2: Geothermal power plants in Indonesia, installed capacity in September 2019

No.	Geothermal working areas	Geothermal power plants	Developers	Turbine units (MW)	Installed cap. (MW)
1	Kamojang Darajat	Kamojang	PT. Pertamina Geothermal Energy	1 × 30, 2 × 55 1 × 60, 1 × 35	235
	Kamojang Darajat (JOC)	Darajat	Star Energy Geothermal Darajat II, Ltd	1 × 55, 1 × 94 1 × 121	270
2	Cibeureum Parabakti	Salak	Star Energy Geothermal Salak, Ltd.	3 × 60, 3 × 65,6	377
3	Dataran Tinggi Dieng	Dieng	PT. Geo Dipa Energi	1 × 60,	60
4	Sibayak Sinabung	Sibayak	PT. Pertamina Geothermal Energy	1 × 10 (m.blok) 2	12
5	Pangalengan (JOC)	Wayang Windu	Star Energy Geothermal Wayang Windu Ltd.	1 × 110 1 × 117	227
	Pangalengan (Patuha)	Patuha	PT Geo Dipa Energi	1 × 55	55
6	Lahendong Tompaso	Lahendong	PT. Pertamina Geothermal Energy	6 × 20	120
7	Waypanas	Ulubelu	PT. Pertamina Geothermal Energy	4 × 55	220
8	Ulumbu	Ulumbu	PT. PLN (Persero)	4 × 2,5	10
9	Mataloko	Mataloko	PT. PLN (Persero)	1 × 2,5	2.5
10	Sibual Buali	Sarulla	Sarulla Operations Ltd.	3 × 110	330
11	Karaha-Cakrabuana	Karaha	PT. Pertamina Geothermal Energy	1 × 30	30
12	Lumut Balai	Lumut Balai	PT. Pertamina Geothermal Energy	1 × 55	55
TOTAL				**40 Units**	**2,003.5**

TABLE 3: Comparison of geothermal business mechanisms in Indonesia

Before Geothermal Law no. 27 of 2003	After Geothermal Law no. 27 of 2003
President Decree no. 45 of 1991 and no. 23 of 1992 *Business structure* based on JOC and ESC *34% of Net Operating Income (NOI)* including all kinds of taxes and retribution, except personal tax *Project Managem.:* Under Pertamina (JOC) and PLN (ESC) *Project type:* ✓ Total (integrated) project. ✓ Partial project *Electricity price / steam price:* Negotiation	*Law no. 27 of 2003 and no. 21 of 2014* *Business structure* in the form of permits: ✓ Geothermal business permit ✓ Enterprise permit for electricity *Obligation to pay taxes, royalty and product. bonus* *Project Management:* Geothermal business permit holders *Project type:* Total (integrated) project *Electricity price / steam price*: Negotiation

TABLE 4: Suggested framework of exploration strategic plan