Technical and Feasibility Study for the San Vicente Geothermal Power Plant Project in El Salvador, Central America.

Angel Monroy

Thesis of 60 ECTS credits
Master of Science (M.Sc.) in Sustainable Energy Engineering

January 2022

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Thesis of 60 ECTS credits submitted to the School of Science and Engineering at Reykjavík University in partial fulfilment of the requirements for the degree of

Master of Science (M.Sc.) in Sustainable Energy Engineering

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Supervisors:

Páll Jensson
Professor, Reykjavík University, Iceland
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Examiner:
Bjarni Palsson

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Abstract

The production of electricity from geothermal energy is forecast to continue growing worldwide. The complexity and high investment cost of a geothermal project require experienced professionals from different disciplines to organize, prepare and deliver a successful project. Historically, geothermal projects were developed without clear guidelines. Nowadays, there are different methodologies between countries and developers. This report proposes nine key development phases and a feasibility study report structure for a specific geothermal project in El Salvador. The technical and feasibility aspects of developing the San Vicente geothermal project can serve as a guideline to prepare a coherent geothermal feasibility study. Three power plant cycles are modelled to examine different scenarios to develop this project. A financial assessment model is carried out by utilising these scenarios their estimated cost, production, and financial assumptions. The proposed scenarios' key performance indicators and financial ratios are analysed to determine the most suitable power plant for the San Vicente project. Using this methodology, geothermal developers, who already know the potential of their project, could technically and financially determine their projects' feasibility.

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Friday, January 14, 2021

Date

Angel Fernando Monroy Parada

Master of Science

This research is dedicated to my wife, family and friends.

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List of Abbreviations

AACE	American Association of Cost Engineering
Ar	Argon
a.s.l.	Above sea level
An	Cash inflows at the end of period n to calculate the terminal value
BC	Bilateral Contracts
BP	Backpresure unit
CEL	Comisión Ejecutiva Hidroelectrica del Río Lempa
CNE	National Energy Council
CDMER	Dean Council of the Regional Electricity Market
CRIE	Regional Electric Interconnection Commission
CMO	Marginal Operation Cost
CP	Capacity Payment
CERs	Certified Emissions Reductions
CDM	Clean Development Mechanism
CS	Cooling system
CD	Common diameter
CAPEX	Capital investments or expenditure
CMAA	Construction Management Association of America
CCF	CCF
DIGEESTYC	Dirección General de Estadsticas y Censos
ESMAP	Energy Sector Management Assistance Program
ESIA	Environmental and Social Impact Assessment
EPC	Engineering Procurement and Construction
ETESAL	Transmission Company of El Salvador
EOR	Regional Operating Entity
EPR	Enterprise Owner of the Regional Electric Network
ESFZ	El Salvador fault zone
Et	Heat Energy
EES	Engineering Equation Solver
E	Evaporator
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
EBIT	Earnings before Interest and Taxes
EBT	Earnings Before Taxes
FRP	Fibreglass Reinforced Polyester
FCFE	free cash flow to equity
GDP	Gross Domestic Product
GW	Gigawatts
G	Generator
He	Helium
IRENA	International Renewable Energy Agency
ICEIDA	Icelandic International Development Agency
ÍSOR	Iceland GeoSurvey
IRR	Internal Rate of Return
J	Jouls
K	Potassium
kW	Kilowatt
KenGen	Kenya Electricity Generating Co., Ltd.
km	Kilometre
kg	Kilogram
kJ	Kilojoules
kPa	Kilopascal
kV	Kilovolt
k	Reinvestment rate

LNG	Liquefied Natural Gas
LTC	Long Term Contracts
lt	Litre
MW	Megawatt
MT	Magneto Telluric
MPIFS	Manual for the Preparation of Industrial Feasibility Studies
MRS	Spot Market
MP	Monomic Price
MG	Magnesium
m	Metre
MIRR	Modified Internal Rate of Return
MARR	Marginal Attractive Rate of Return
NDF	Nordic Development Fund
NEP	National Energy Policy
Na	Sodium
N_2	Nitrogen
NCG	Non-Condensable Gas
NPV	Net Present Value
OLADE	Latinamerican Energy Organization
O&M	Operation and maintenance
ORC	Organic Rankine Cycle
Ohm-m	Ohm-metre
OPEX	Operating expenses
PPA	Power Purchase Agreement
PM	Market Participants
PV	Photovoltaic
PH	Preheater
PPPI	Power Plant Stages I
PPPII	Power Plant Stages II
$PV(I_0)$	Present Value of investment cash flows
MER	Regional Electricity Market
ROBCP	Transmission System and Wholesale Electricity Market Operation Based on Production Cost Regulation
SIGET	Superintendencia General de Electricidad y Telecomunicaciones
SIEPAC	Central American Electricity Interconnections System
SC	System Costs
SV	San Vicente
SSI	Silica Saturation Index
s	Seconds
SF	Single flash unit
TWh	Terawatt-hour
TEM	Transient Electro-Magnetic
TDEM	Time Domain Electro-Magnetic
TTD	Terminal Temperature Difference
T	Turbine
UT	Transaction Unit
USGS	United States Geological Survey
US BLS	U.S. Bureau of Labor Statistics
wt	Weight
Y	Year
°C	Degree Celsius

List of Symbols

Symbol	Description	Value/Units
C	Specific heat	J/°C*kg
C_i	Cost of size i	USD
C_o	Cost of size o - reference	USD
$C_{T\&G}$	Turbine and generator cost	USD
C_{HX}	Heat exchanger cost	USD
C_{AC}	Air-cooled condenser cost	USD
C_P	Pumps cost	USD
E_t	Total heat energy	J
E_r	Rock energy	J
E_w	Water energy	J
H	Reservoir thickness	M
$h_{[\,]}$	Enthalpy	kJ/kg
K_i	Size or rating of units	MW
K_o	Refernce size or rating of units	MW
L	Power plant capacity factor	%
$m_{[\,]}$	Mass flow	kg/s
n	Scaling exponent	typically ~2/3
P	Power plant capacity	MW
$P_{[\,]}$	Pressure	kPa
Pa	Atmospheric pressure	kPa
R_f	Recovery factor	%
$s_{[\,]}$	Entropy	kJ/kg*°C
T	Power plant lifetime	years
T_r	Average reservoir temperature	°C
T_0	Reference temperature	°C
$T_{[\,]}$	Temperature	°C
T_{WB}	Wet-bulb temperature	°C
TTD	Terminal temperature difference	°C
φ	Porosity of the rock	%
V	Volume	m^3
W	Unit capcaity	MW
$x_{[\,]}$	Quality	-

Chapter 1

Introduction

Electricity generation from geothermal energy began in 1904 at Larderello in the Tuscany region of northwest Italy with an experimental 10 kW generator. Since then, there has been an interest in developing and utilising geothermal resources for electricity generation worldwide. Nowadays, countries are also looking to use geothermal for direct uses, like space heating, agriculture drying, industrial uses, bathing, and swimming.

However, the exploitable energy potential in countries with geothermal resources is greater than the current utilisation, which indicates that geothermal has many opportunities to play an important role in the electricity matrix in these countries. Geothermal resources have been identified in nearly 90 countries, and electricity is produced by geothermal energy in 24 countries (Gehringer & Loksha, 2012).

The International Energy Agency report that between 2017 and 2040, renewable electricity generation will grow from 25% to just over 40% in the power mix of the global electricity generation. Regarding this, geothermal represent 1% of renewable technologies investment (International Energy Agency, 2018).

In 2016, the worldwide installed capacity was 12.7 MW, and approximately 74 TWh of electricity was produced from geothermal energy in 51 countries. The worldwide installed capacity has been increasing on average by 16% from 1995 to 2015. The top five countries with the highest installed capacity for geothermal in 2015 were the USA (3,450 MW), Philippines (1,870 MW), Indonesia (1,340 MW), Mexico (1,058), and New Zealand (1,005 MW) (Bertani, 2016).

The role of geothermal energy in the market share in countries like Iceland (25%), El Salvador (22%), Kenya and the Philippines (17% each), and Costa Rica (13%) is demonstrating the interest of those countries to use their natural resources and to generate renewable and sustainable energy to supply their electricity demand (International Energy Agency, 2011b).

Geothermal projects require and involve different efforts from scientists, technicians, engineers, administrators, environmentalists, lawyers, and financiers, etc., to analyse and prepare reports to plan milestones needed in each phase of the project for its development.

High upfront costs represent an even more imposing barrier for geothermal projects than for other renewable energy projects, as significant upfront investments are required before the risks can be reduced to a financial level. This is caused by the fact that the presence of a suitable geothermal reservoir can only be assured after a successful exploration drilling campaign has been completed (IRENA, 2017).

This report proposed a guideline on preparing a feasibility study for geothermal power projects with the primary purpose of producing electricity. The proposed structure can also be followed for direct use geothermal projects.

Chapter 2 - Phases of a geothermal project and feasibility studies, presents how geothermal projects were developed from different styles to develop projects in organized phases where the risks and costs of the project vary along with the project progress. The three first phases to develop a geothermal project are seen as the riskiest portion of a geothermal project, and significant investment is required to know if the geothermal resource has enough potential to produce electricity and recover the investment.

At the same time, early and the stepwise strategy used to develop the geothermal project are presented, and it has been pointed out that the stepwise approach has considerable economic and technical benefits.

Finally, this chapter presents a structure to prepare a feasibility study for a geothermal project. A study that collects the technical and financial information to provide confidence with well explained and supported evidence of the project´s viability for both the developer and potential financier.

Chapter 3 - Project concept and background, introduce the geothermal development in El Salvador since the beginning of the 1960s to date. At present, LAGEO S.A. de C.V. is the only geothermal company in El Salvador whit a total installed capacity of 204 MW.

In 2004, the company received a concession for exploring and developing the San Vicente geothermal fields. This chapter defines the project owner, objectives and project status.

Chapter 4 - Country electricity market status, presents El Salvador electricity market evolution, status, structure and describes its operation. At the same time, the chapter presents the importance of developing the San Vicente geothermal field by utilizing the country's natural resources to diversify the electricity market share and reduce the risk of price rises due to the increase and variability of fossil fuel costs. This chapter presents the electricity price's performance based on the production cost regulation ROBCP, which explains why the electricity price depends on the international oil price. To finally, present the country tax incentives for new geothermal projects.

Chapter 5 – Geothermal resource assessment, presents the characteristics of the San Vicente geothermal reservoir based on the geological, geochemical and geophysical surveys carried out at the project area to prepare the conceptual model of the geothermal system that has been identified. The conceptual model presents and describes the heat source, recharges zones, geofluid circulation pattern, cap-rock, reservoir boundaries and ticknes, up-flow zone and discharge zone of the reservoir. Additionally, the resource estimation using the volumetric method has been carried out, concluding that the San Vicente geothermal project can sustain a production capacity close to 30 MW. To finally present the harnessing development plan, which is the arrangement to develop the project in two stages, one with a power plant in the range of 10 MW and the second stage with a unit in the range of 20 MW to complete the estimated capacity of 30 MW.

Chapter 6 - Engineering and technology, presents a description and technical specifications for the wells, pipelines, gathering systems, separators, flashers, turbines, heat exchangers, condensers and cooling towers that are considering the principal components for the San Vicente power plant project's design. In this chapter, the power plants technologies that will be proposed for this project are modelling using a computer program based on the harnessing plan presented in Chapter 5 and the technical assumptions for each stage of the development. At the same time, the selection of the condensing pressure, one of the parameters that are a cost-driven factor for the project, is carried out. Finally, the description and technical specifications of the gathering systems and power transmission lines are presented.

Chapter 7 – Financial assessment model, presents the CAPEX, OPEX and their distribution over their project life based on the AACE recommendations to estimate the project cost according to its maturity. The San Vicente project is classified in estimation costs Class4, and the project’s cost can be updated as the project has a level of definition. At the same time, this chapter presents the methods used to estimate the project’s components cost and group in its respective phases. Finally, the chapter presents the discussion on the results of the financial model and the sensitivity analysis that had been carried out for the San Vicente project. One of the finical model results, utilizing the accumulate NPV as an evaluation criterion, is that all scenarios paid the load required to develop the project. Additionally, from the sensitivity analysis is determined that the electricity price and the power production are the most sensitive parameters of the project. With all these results, the most suitable scenario to develop this project will be determined.

The present report serves as a technical guideline to understand and prepare the information required to formulate a feasibility study for a geothermal project.

Chapter 2

Phases of a geothermal project and feasibility studies

Historically, geothermal projects were developed in different ways and styles. There were no clear guidelines for the geothermal development process. It is only with experience that the phases of how to develop a geothermal project have been improved. Currently, there are different methodologies and techniques between countries and developers (GeothermEx Inc. & Harvey, 2013). Geothermal projects are developed in phases, with various stages, depending on the developer and the best practice selected, but the basic activities must be the same.

Each phase of project development has numerous activities and involve a decision milestone. This thesis report identifies and briefly describes the key development phases that a geothermal project should be specified as a technical requirement during its lifecycle, modified and following the structure from the ESMAP Geothermal Handbook.

2.1 Phases of geothermal project development

Geothermal projects have been divided into a series of development phases before the operation and maintenance development phase starts. The development of a typical geothermal project will usually take between 5 to 10 years. The project development time might vary, depending on each site and country. Some reasons are the relevant country's geological conditions, information available about the areas, institutional and regulatory situation, weather, politics, financing, environmental conditions, and other factors (Gehringer & Loksha, 2012).

A comparison from different geothermal actors like developers, supporting organisations, financing groups, and project owners on how many phases are required in geothermal projects is summarised in Table 2-1. The Energy Sector Management Assistance Program (ESMAP) as a financing group and The International Renewable Energy Agency (IRENA) as an international supporting organisation consider eight to nine phases to develop a geothermal project. The experience of Dr Pálssson, who works at the National Power Company of Iceland, consider six phases (Pálsson, 2017, 2019). The Latinamerican Energy Organization (Organización Latino Americana de Energía - OLADE), as regional supporting agencies divides the geothermal project into four phases (Monterrosa, 2009). The Geothermal Exploration Project in East Africa proposed nine stages for geothermal development (Icelandic International Development Agency & Nordic Development Fund, 2013). Moreover, KenGen (Kenya Electricity Generating Co., Ltd.), a developer and project owner, considers four phases in developing a geothermal project (Ngugi, 2009).

Table 2-1 Phases for exploration and development of geothermal projects from the point of view of different developers and project owners

REFERENCE	ESMAP	PÁLSSON	MONTERROSA	ICEIDA & NDF	NGUGI	IRENA
Phase I	***Preliminary Survey***	***Reconnaissance***	***Reconnaissance***	***Reconnaissance***	***Resource Exploration***	***Identification***
Steps	Data collection Inventory nationwide survey Selection of promising areas EIA & Necessary permits Planning of exploration	Desktop study Surface exploration – Phase I (geology, geochemistry, geophysics) Exploration report	Covers a very large area perhaps more than 1,000 km^2	Gathering of existing data	Review of existing information Detailed surface exploration Exploration drilling and well testing	Siting study
Phase II	***Exploration***	***Pre-Feasibility***	***Prefeasibility***	***Exploration***	***Resource Assessment***	***Screening***
Steps	Surface (Geological) Subsurface (Geophysical) Geochemical Soundings (MT/TEM) Gradient & Slim holes Seismic data acquisition Pre-feasibility study	Exploration program Exploration / Appraisal drilling Reservoir assessment	Covers 400-500 km2 2 exploratory wells	-	Appraisal drilling and well testing Feasibility study and environmental impact assessment	Concession rights Acquisition
Phase III	***Test Drillings***	***Feasibility***	***Feasibility***	***Exploration drilling***	***Power Plant Construction***	***Assessment***
Steps	Slim holes Full size wells Well testing & Stimulation Interference tests First reservoir simulation	Confirmation drilling Reservoir engineering Feasibility study Value engineering Decision to tender	Covers 10-100 km2 Surface exploration Resource assessment 5 wells drilled	-	Production drilling Power plant design constructions and commissioning	Resource assessment Surface exploration work ESIA
Phase IV	***Project Review & Planning***	***Project Design***	***Development and commercial exploitation***	***Prefeasibility***	***Operations***	***Selection***
Steps	Evaluation & Decision making Feasibility study & final EIA Drilling plan Design of facilities Financial Closure / PPA	Tender design Tendering and procurement Financial analysis Decision to construct	Construction of the power unit and additional wells	Prefeasibility report	Reservoir management and further development Power plant operations	Financing PPA and Implementation Agreemen
Phase V	***Field Development***	***Construction***	-	***Further drilling of wells***	-	***Pre-development***
Steps	Production Wells Reinjection Wells Cooling Water Wells Well Stimulation Reservoir Simulation	Construction Project control and Supervision Commissioning Hand-over	-	Further drilling of wells – as needed	-	Exploration drilling
Phase VI	***Construction***	***Operation***	-	***Feasibility***	-	***Development***
Steps	Steam / Hot water pipelines Power plant & cooling Substation & Transmission	Operation Monitoring Maintenance Make-up drilling Refurbishment Decision to abandon	-	Feasibility report	-	Financial closing and tendering EPC contracts for Power plant
Phase VII	***Start-up & Commissioning***	-	-	***Concept design and tender documents***	-	***Execution***
Steps	-	-	-	-	-	Construction and drilling of production wells and commissioning
Phase VIII	***Operation & Maintenance***	-	-	***Detailed design and construction***	-	***Operation & maintenance***
Phase IX	-	-	-	***Testing, training and operations start-up***	-	***De-commissioning***

FromTable 2-1 Phases for exploration and development of geothermal projects from the point of view of different developers and project owners, it is important to highlight that there are different phases and processes to develop geothermal projects, but the main stages involve many similar activities. At the same time, development phases help to understand better the geothermal field, its reservoir, and the risk that developers face during a project. However, it is important to identify that they are connected and have common decision milestone to help the project developers agree on whether to proceed to the next phase or stop the project.

This thesis report identifies and briefly describes in the next section nine key development phases, presented in Table 2.2, that a geothermal project should include a technical requirement during its lifecycle. These phases are mainly modified from the ESMAP Geothermal Handbook structure (Gehringer & Loksha, 2012).

Table 2-2 Key development phases that a geothermal project should be specified as a technical requirement during its lifecycle.

PHASE 1	***Preliminary Survey***	Gathering of existing data Desktop study Inventory nationwide survey Siting study Selection of promising areas (recommended 1,000 km2) Planning of exploration Detailed surface exploration (geology, geochemistry, geophysics) Exploration report EIA & Necessary permits
PHASE 2	***Resource Exploration***	Review of existing information Detailed surface exploration (400-500 km2) (geology, geochemistry, geophysics) Soundings (MT/TEM) Gradient & Slim holes Seismic data acquisition Exploration drilling and well testing (2 - 3 wells) Reservoir assessment Pre-feasibility study Concession rights
PHASE 3	***Test Drilling and Feasibility***	Surface exploration work covers 10-100 km2 Confirmation drilling Full size wells (5 wells drilled) Well testing & Stimulation Interference tests Resource assessment - First reservoir simulation Feasibility study Decision to tender ESIA
PHASE 4	***Project Review, Planning & Design***	Evaluation & Decision making Drilling plan Design of facilities PPA and Implementation Agreement Financial analysis Feasibility study & final EIA Financial Closure / PPA Tender design Tendering and procurement Decision to construct
PHASE 5	***Field Development***	Further drilling of wells – as needed Production Wells Reinjection Wells Cooling Water Wells Well Stimulation Reservoir Simulation
PHASE 6	***Construction***	Construction of the Power plant & cooling Substation & Transmission Drilling additional wells - as needed Steam / Hot water pipelines Project control and Supervision Commissioning
PHASE 7	***Commissioning, training and operations start-up***	Commissioning Hand-over
PHASE 8	***Operation & Maintenance***	Power plant operations Reservoir management and further development
PHASE 9	***Decommissioning***	-

These phases are presented in Figure 2-1, where the risks and costs of the project are related. The three first phases defined are seen as the riskiest portion of a geothermal project and confirm if a geothermal reservoir is suitable for producing electric power. If a suitable reservoir is successfully confirmed during these phases, developers decide to continue with the project until the operation and maintenance phase starts (Gehringer & Loksha, 2012).

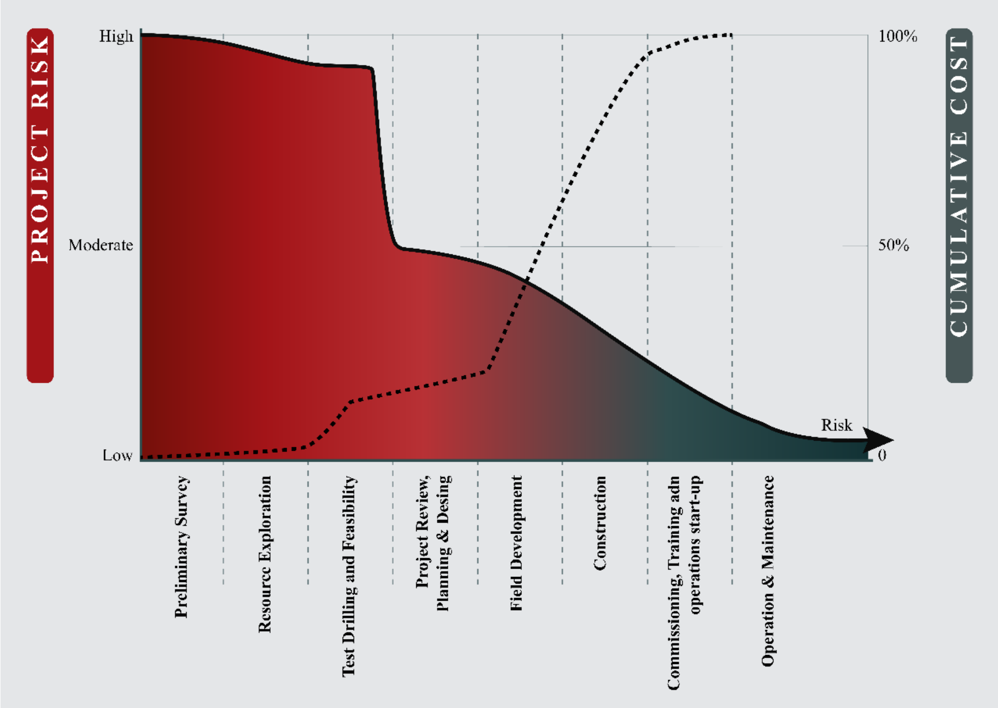


Figure 2-1 Geothermal project cost and risk profile over the phases of development. Modified from (Gehringer & Loksha, 2012)

Phase 2 – Resource Exploration requires the drilling of two to three wells and needs more capital than the previous phase with high uncertainty percentage. This uncertainty and high project risk mean it is not easy to estimate the geothermal field's resource capacity, and getting funding will be challenging. Before the Field Development and Construction phases start, significant investment is required to know if the geothermal resource has enough potential to recover the costs. One viable way to overcome this mature risk on geothermal projects involves government attention and support (Gehringer & Loksha, 2012; IRENA, 2017).

The following section describes and presents the phases of project development, as defined for this report, and can be considered as a guideline for further geothermal project development in Latin America and other regions.

2.1.1 Preliminary survey

The preliminary survey phase is the first reconnaissance activity. It starts practically as a desktop study, collecting and analysing data based on national or regional information available to verify the existence of geothermal resources and define the area of interest. Reconnaissance and data collection might be initiated by a project developer interested in starting a geothermal project to explore its potential in more detail. A government interested in development for a specific area of geothermal interest may also open for tendering. It can even be an entrepreneur who wants to utilise geothermal energy as a sustainable energy source for their business (IRENA, 2017).

The preliminary survey includes:

- Literature review of geological, hydrological, thermal and drilling data, anecdotal information from local populations, and remote sensing data from satellites, if available (GeothermEx Inc. & Harvey, 2013)
- Identify geothermal manifestations, take samples, assess site accessibility and access roads, water and power supplies, local communities, possible environmental issues, and national and local safety concerns
- Explore the feelings of the communities surrounding geothermal areas to identify any social risk that may need to be addressed during the project at an early stage of the development
- A site visit is required to understand the scientific data to know the area better, and it will be the first approach for the environmental assessment

The process of obtaining a concession right, permits and licenses for project development and operation, and identifying stakeholders are other key activities for this phase. Depending on the regulatory frame for each country, developers need to understand the process for obtaining and retaining the legal rights to develop the geothermal resource (Gehringer & Loksha, 2012; IRENA, 2017). In El Salvador, a concession to explore and utilise geothermal resources must be authorised by the Legislative Assembly (Diario Oficial, 2013).

In this phase, a preliminary exploration report identifying an area with a reliable geothermal source describing the scientific and technical characteristics and boundaries, the exploration plan for the next phase, the list of documents required by countries' institutional and regulatory frameworks, and the possible environmental and social issues must be addressed.

2.1.2 Resource exploration

The resource exploration phase starts with a detailed review of the existing data collected in the preliminary survey. The detailed multidisciplinary exploration plan defined in Phase 1 and new surface surveys in areas that had not been studied in detail is executed. After more data is collected, the studies focus down on a more localised analysis. The project developer has the possibility to drill two or three exploratory wells to confirm the existence of a geothermal field. The main goal of the resource exploration phase is to minimise the risk related to resource temperature, depth, productivity, and sustainability before the next phases begin (GeothermEx Inc. & Harvey, 2013).

For this phase, the program includes various methods, which can include the following exploration surveys:

- Geological surveys, which usually include lithological mapping, structural geology, volcanism, hydrogeology, geo-hazards, and environmental geology
- Geophysical survey includes gravity, seismic, magnetic, and electromagnetic measurements. For geothermal exploration, various methods can be applied, including Schlumberger, TEM (Transient Electro-Magnetic), TDEM (Time Domain Electro-Magnetic) and MT (Magneto Telluric)
- Geophysical exploration with Bouguer gravity measurements complements MT and TEM measurements
- Results of geophysical survey combined with geological data can lead to the location of the heat source and define the potential drilling targets

- Geochemistry surveys take samples of surface water, underground water, hot springs, natural steam, and gases. The results determine the degree of permeability associated with the reservoir rock structure and the temperature of hot water at a depth of the reservoir based on its chemical elements in solution, estimate the speed of hot water circulation, and clarify the history of hot water (fluid´s origin and recharge)
- Heat flow or soil temperature surveys helps map faults or fissures which control the flow of geothermal fluids. These surveys show information about heat sources and help interpret other data (Ochieng, 2016)

Table 2-3 Examples of outcomes for each methodsummarises examples of good outcomes from data collected during the surveys methods.

Table 2-3 Examples of outcomes for each method (GeothermEx Inc. & Harvey, 2013)

Existing data base	Geological surveys	Geophysical survey	Geochemistry surveys
A good outcome upon completion of the literature and published data review is to have high confidence that all relevant data and maps have been identified, collated, and assessed for inclusion in the conceptual model of the resource.	A good outcome from the geological analysis is a clear picture of the regional and local geology, stratigraphy, and tectonic structure of the area. This information should indicate which units or structures could host a geothermal reservoir, and forms the basis for subsequent conceptual and numerical models.	Good outcomes of geophysical investigations include, but are not limited to; an indication of the temperature distribution both horizontally and vertically, improved knowledge of the geological structure and stratigraphy, and indications of fluid migration pathways and reservoir boundaries.	A good outcome following analysis of the active geothermal features would be an estimate of the rate of geothermal fluid movement through the system, and an idea of the extent and general geometry of the geothermal resource. A good outcome of the geochemistry studies would be an indication of temperature distribution within the geothermal system, a maximum temperature range for the resource, and a fluid-mixing model.

During the resource exploration phase, detailed surveys are needed. However, budget constraints must be considered. The data collected is used to develop the first approach to the conceptual model of the geothermal system, which estimates reservoir properties, such as permeability, flow parameters, temperatures, thickness, and areal extent.

A good conceptual model indicates that the developer has considered and integrated all existing data. The conceptual model will validate a justified understanding of the geothermal system geology, temperature, and fluid circulation. By utilising the conceptual model, the developer can select drilling sites and targets that maximise the likelihood for a successful well based on all current data. Figure 2-2 shows how all of the data collected is integrated into a conceptual model and how the model is constantly refined as more data are acquired.

The first conceptual model, a detailed geoscientific report covering the explored area, the first volumetric resource assessment, selected sites and targets for the next deep exploration wells will be addressed in the resource exploration phase. In addition to this, the developer should be able to deliver a Pre-Feasibility study before the decision is made to perform the test drilling and feasibility phase (IRENA, 2017).

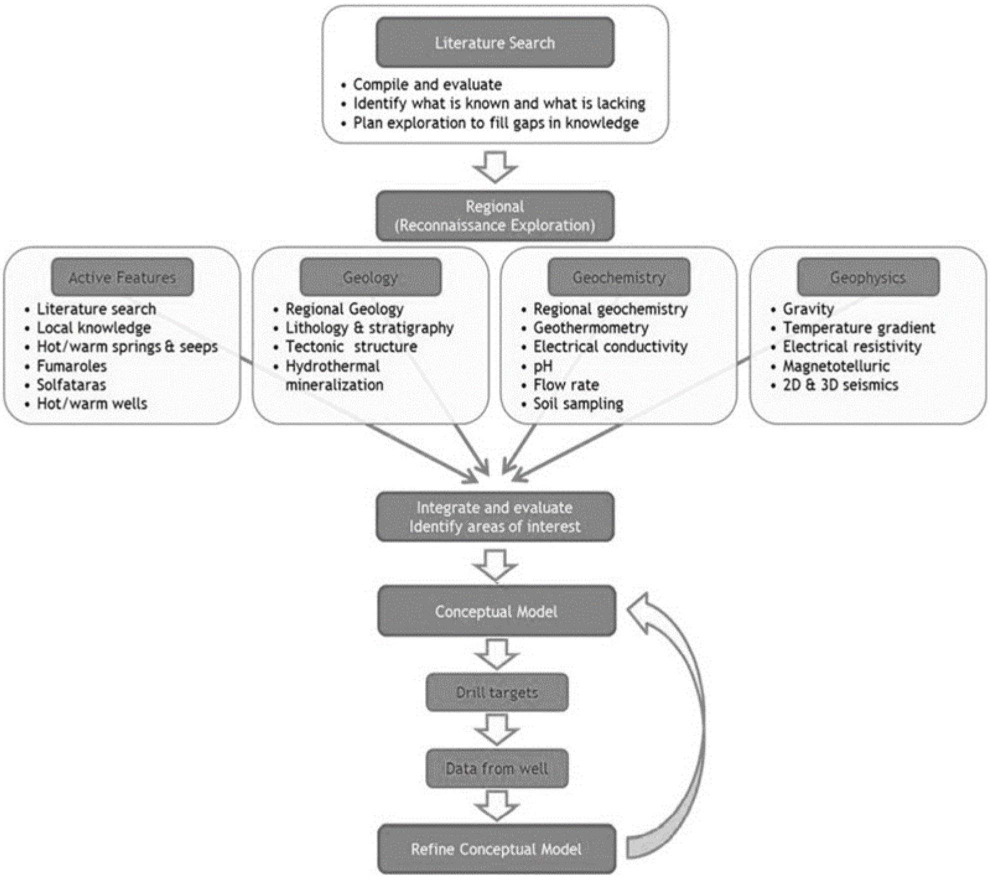


Figure 2-2 Flow chart showing how data acquired is integrated into a conceptual model, modified form (GeothermEx Inc. & Harvey, 2013)

2.1.3 Test drilling and feasibility

The test drilling and feasibility phase is the last exploratory phase (Gehringer & Loksha, 2012). It aims to confirm the existence of the geothermal reservoir and estimate the reservoir´s potential to generate electricity.

Based on the conceptual model, a drilling program is designed, and usually, three to five full-sized wells are prioritised with 2 to 3 km deep. These wells are the most critical ones to get as much downhole information as possible to identify the reservoir (Aragon-Aguilar et al., 2019). Drilling slim holes is another option as such wells can be drilled to 1.5 km at less cost than a similar depth full-sized well.

It is worth mentioning that drilling plans must be continuously evaluated during the drilling activity, evaluating the well's logging and discharge testing data. Suppose the first well does not produce enough steam. In that case, downhole data is evaluated in conjunction with the initial detailed geological, geochemical, and geophysical studies before deciding to drill the next well. Results of the well logging and discharge tests, together with reports from the previous phases, helps to develop a more well-defined conceptual model. Wells often do not discharge after drilling even if there are sufficient permeability and high-temperature indications. In such cases, well stimulation methods are applied to induce well discharge (Dolor, 2006).

Drilling, logging, and testing wells improve the reservoir's understanding and lead to a better approach to the heat source location. Additionally, this data provides information to determine the average well productivity, site and design of the wells, confirm the drilling targets, and develop a conceptual design for the power plant and gathering system (GeothermEx Inc. & Harvey, 2013). The Environmental and Social Impact Assessment (ESIA), and all the permits with the appropriate entities are required to be developed in this phase.

The project's feasibility study report is the main deliverable in this phase. This thesis report will be focused on and present a structure to make a feasibility study for a geothermal project in Latin America, specifically in El Salvador. Moreover, this thesis can be used as guidance to formulate future geothermal feasibility studies.

The exploration and drilling tests phases require a high investment, but the cost varies for a specific project. At this point of development, funding support from governments is often the only way to reduce developers' exploratory risks and guarantee the benefits of using its natural resources. Funding geothermal projects with a commercial or multilateral lender are only possible after evidencing 62% of the estimated potential power development through well testing (Zarrouk & McLean, 2019).

2.1.4 Project review, planning, and design

In the project review, planning, and design phase, the limits and size of the resource are established based on the technical characteristics presented in the conceptual model such as the heat source, geological structure, circulation fluids and geochemistry of the geothermal area. Additionally, the power plant location and conceptual design, gathering system, interconnection to the national power grid and Power Purchase Agreement (PPA) are established. Finally, public surveys with residents, local government, and other stakeholders are also undertaken to prepare the ESIA following national or international environmental laws, standards, and regulations.

Once the resource has been confirmed and defined based on the previous phases, the project risks are significantly reduced; an accurate technical and financial feasibility study can be prepared. The feasibility study provides to the developer and potential financiers confidence in the project's viability (GeothermEx Inc. & Harvey, 2013).

2.1.5 Field Development

The field development phase involves drilling production and reinjection wells needed to complete the field development strategy according to the power capacity target. Also, it marks the beginning of the detailed design, procurement and construction of the power plant. The detailed engineering, procurement and construction of the geothermal power plant, as well as substation and transmission lines are completed simultaneously with the drilling of the production and reinjection wells (Dolor, 2006).

Once the reservoir's capacity has been proven, and the power plant's conceptual design is defined with the optimal size, the specific technologies for the project can be determined. The conceptual design provides the basis for the final design, and the tendering document must be prepared and circulated to find the best contractor (IRENA, 2017).

It is a good practice, in this phase, establish a baseline of the timetable for the project. The project's timetable shows the activities that must be completed, the logical sequences, the interdependencies of the activities, and the times for the activities to start and finish to identify the critical path. The timetable is the scheme for the project information system used by decision-makers concerning the project time, cost, and performance (Larson & Gray, 2018a).

2.1.6 Construction

The civil works required for the steam gathering system and the power plant are completed in the construction phase. The contractor does all the civil, electrical, and mechanical work. Power plants are often constructed using Engineering Procurement and Construction (EPC) contracts. The EPC contractor is responsible for the detailed final design, procurement, construction, and commissioning until the plant is transferred to the owner and operator.

In this phase, the project developer implements the EPC construction works, and at the same time, drill the production and reinjection wells required to secure enough steam for the power plant. At the end of this phase, the developer should be able to commission the power plant at full capacity (IRENA, 2017).

2.1.7 Commissioning, training, and operations start-up

The power plant´s commission, training and operation start-up is the final phase of the EPC contract and is when the plant has started its unofficial commercial operation and maintenance. This phase usually involves the evaluation of the compliance of the performance of the power plant with the technical specifications defined in the contract, and solving any technical and contractual issues with the contractor of the plant. The main goal in this phase, is to optimise the production system to perform at the best point of efficiency, to guarantee the minimum performance conditions defined in the contract and the sustainable use of the geothermal fluids and reservoir capacity.

Fine-tuning on the efficiency of main and auxiliary equipment of the power plant, including the setting of operation points of pressures for the production and reinjection wells can take several months to complete the delivery of a fully functional producing plant. To ensure safe and reliable operation and maintenance (O&M), it is important to have and train qualified O&M staff onsite. Lessons learned from other experiences can contribute to the training stage (Gehringer & Loksha, 2012; IRENA, 2017).

2.1.8 Operation & Maintenance

Geothermal power plants are considered base load units by the capacity to operate at constant output for long periods of time without shutdowns. Additionally, during the startup time for the gathering systems and the power plant equipment (time to gradually heated up and pressurise), it is recommended to avoid frequent output change or shutdowns to minimise the fatigue of the casing wells, pipelines, and equipment (IRENA, 2017).

The operation and maintenance can be divided into the O&M for the steam field (wells, pipelines, infrastructure, etc.) and the O&M of the power plant (turbine, generator, cooling system, substation, etc.) (Gehringer & Loksha, 2012). Best practices maintain all facilities at a high availability factor[1] and capacity factor[2] for the power plant and ensure stable steam production from the geothermal wells. Monitoring and looking at the trend of these factors helps to know how O&M is functioning for the plant. For geothermal power plants, the capacity factor can be affected by the quality of the geothermal fluid, the plant technology, design, external conditions, the national grid stability, and the technical capacity of the O&M staff. The capacity factor for geothermal power plants is about 70% worldwide (e.g. Unit 3 in Ahuachapán Geothermal power plant in El Salvador operates at ~76.7%). In some countries, these percentages can go as high as 90% or even a little more (e.g. Nesjavellir, Geothermal power plant in Iceland operates at ~95%) (Amaya, 2009; IRENA, 2017).

The power plant operations need well-trained technical staff. On average, a single operator worker is needed for each 4 to 8 MW of installed capacity. Additionally, one maintenance worker will be needed for each 6 to 10 MW of installed capacity. The averages of required staff can vary depending on each country market structure and demand. Suppose a power plant trip occurs, and the geothermal share in the electricity market is significant for the country, this power plant needs to be reestablished as soon as possible, and workload at those conditions demand technicians to be available on-site. Furthermore, the staff training at all levels should continue during the operation life of the project and be supported by certified institutions and consultants (OLADE & IDB, 1994).

2.1.9 Decommissioning

Along with the geothermal resources used to produce for a long time, the reservoir pressure is expected to decline, so the steam output drops. Consequently, the equipment of the power plant and all the facilities will perform at a lower point of efficiency, meaning that it is not economical for continued operation of the power plant, requiring it to be shut down and decommissioned.

The project developer should schedule activities to decommission the wells and clean up the geothermal pad and facilities in the decommissioning phase. It is a good practice to look for other uses of the geothermal facilities, analysing future scenarios with reusing and recycling options. The project developer should be able to ensure a safe and clean site at the end of the entire lifecycle of the project. This phase demands a complex process with technical, environmental, health and safety challenges. Depending on each country's regulatory framework, developing a geothermal project may requires a decommissioning phase (DiPippo, 2016a). To comply with all of the concession arrangements, a clear long-term association with a public agency is recommended.

Here is the importance of managing the geothermal resource in sustainable ways to extend as much as possible the project lifetime and delay the need to begin the decommission phase as far as possible. The Ahuachapán geothermal field in El Salvador has been utilised since 1975 (Amaya, 2009; IRENA, 2017). Based on this, the first reservoir lifetime assumption can be assumed between 30 to 50 years for a new geothermal project until the reservoir is stable, well known, and managed.

[1] Availability factor is defined as the amount of time that a power plant is able to produce electricity over a certain period, divided by the amount of the time in the period.

[2] Capacity factor is defined as the ratio of the actual output of a power plant over a period of time and its output if it had operated at full nameplate capacity the entire time.

2.1.10 Phase costs and time

Table 2-4 shows the rough estimated cost that was calculated with the three-point method using data from ESMAP (2012) and Dolor (2006). At the same time, this table shows an indicative time required to develop each phase.

Table 2-4 Indicative costs and time for geothermal development phases based in a 50 MW project (Dolor, 2006; Gehringer & Loksha, 2012).

PHASE		TIME (years)	COST US$ Million	COST ASSUMTIONS
1	*Preliminary Survey*	1	2.3	This cost assumes that the basic geology information is available.
2(1*)	*Resource Exploration*	2	7.8	This costs depends on the size and accessibility of the geothermal site, the availability of the technical equipment and the number and size of the exploratory wells.
3(2*)	*Test Drilling and Feasibility*	2	24.5	This cost depends on the wells design (size and depth) to be drilled, the drilling contract and the conditions of the facilities in the geothermal field
4	*Project Review, Planning & Design*	3	7.2	This cost cover the detailed engineering, permitting negotiation, land access, environmental surveys, consultant services and the technical work necessary to move the project into the field development and construction phases
5(3*)	*Field Development*	2	116.7	This cost depends on the drilling programme and contract. The cost of each well ranges between US$4 to US$5 million for a full sizes wells of 2.5 to 3 kilometres deep
6(4*)	*Construction*	2	101.2	This cost is based on a turnkey contract, starting with the construction of the pipelines, gathering system, power lines and the power plant unit. This contracts are usually in the range of US$ 1 to 2 million per megawatt.
7	*Commissioning, training and operations start-up*	1	5.2	Cost of this phase are part of the construction phase

1* In this phase 2 to 3 wells are required to confirm the reservoir, those wells can be slim hole at US$1.5 millions or full size at US$6 millions
2* This phase consider maximum 5 full size wells with a depth of 3 kilometres at a estimated cos of US$6 millions
3* This cost assume that the project needs maximum 20 geothermal wells
4* The construction contract is based on a 50 MW power plant

2.2 Strategies to develop geothermal projects

"Early strategy" is used to develop a geothermal project to utilise each field's maximum capacity in one power plant. The strategy needs to know each field's maximum generation capacity before deciding on the power plant installed size to be built. Earlier strategy demands time, effort, and investment in exploration, drilling, well testing, reservoir monitoring, and engineering to identify the optimum capacity to select the power plant size.

In 1982 in Iceland, a strategy for exploring high-temperature fields was analysed, and a generic plan was estimated and presented. Before deciding whether to continue with the power plant building, the plan considers that ten years of intensive exploration, drilling, and well testing activities are needed. Nowadays, when the reservoir generating capacity is known, a stepwise development strategy has been applied. A relatively small (20 – 50 MW) power plant is built and commissioned as a first step in the stepwise development strategy. As a result of this first step, the project reaches its commercial operation period early, then the full-size strategy with a certain percentage of the total estimated capacity of the reservoir is added.

Armannson et al. comments that several examples of geothermal projects worldwide have been discussed, and it has been pointed out that compared with the early strategy, the stepwise approach has considerable economic benefits. Furthermore, the reservoir behaviour can be monitored and evaluated on how it responds during the first years of production to determine if and when the next project phase can be developed until the reservoir's total capacity is reached and fully utilised (Ármannsson et al., 2015). A comparison of these two strategies is shown in Figure 2-3.

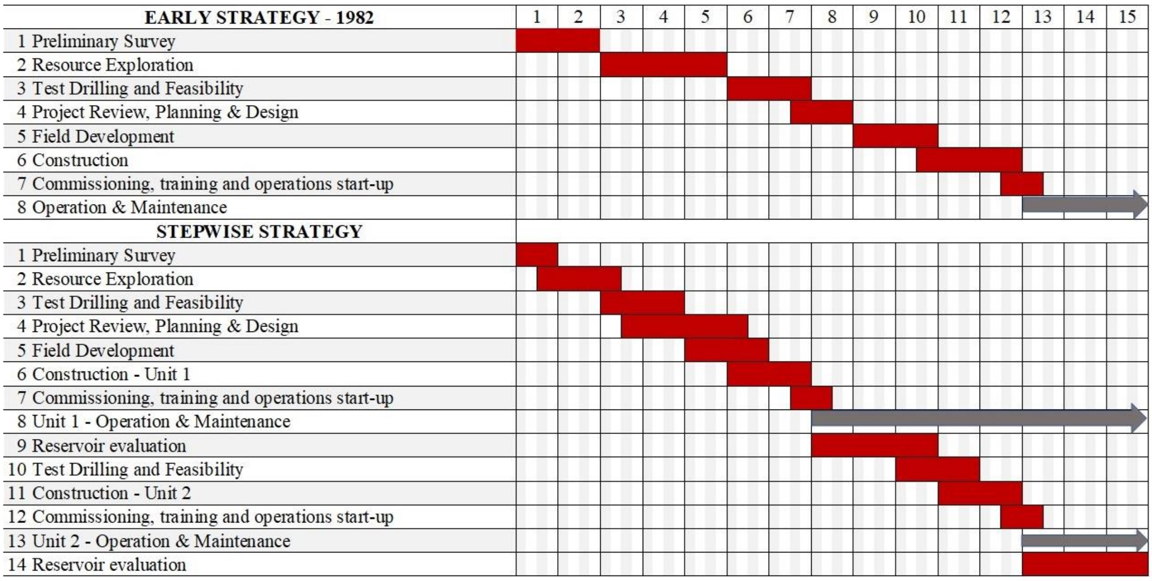


Figure 2-3 Comparison of the conventional development and the stepwise development strategy modified from (Ármannsson et al., 2015).

Practically, applying the stepwise strategy, the activities to develop a geothermal project from the early strategy method are divided in time and consist of developing the same activities in more than one step to utilise the maximum reservoir capacity that has been identified.

Another stepwise strategy that can be applied to speed up geothermal developments is to utilise small-scale, low-cost, quick-installation of modular units. These modular units can be placed in the well pad once the first production well is completed and able to produce for some transitional period. The modular technologies vary from small condensing single flash, binary cycle and backpressure units. El Salvador, Nicaragua and Mexico are successful examples of using wellhead backpressure units as the first step taken to develop geothermal fields. The backpressure units were the same for each case and were replaced by more efficient condensing single flash units. However, the backpressure units delivered valuable well production data, reservoir behaviour, worthy operation experiences, and improved the developer cash flow. For the El Salvador case, the operation of these backpressure units during its first five years provides useful long-term reservoir test information that helps to define the appropriate plant design parameters for the actual condensing units (Unit 1 & Unit 2) at Berlin power plant. Finally, this modular strategy can reduce the early utilisation of the geothermal resource even more if second-hand units are considered because they could be operational in around half a year (Wallace et al., 2018).

The stepwise strategy development might start once the first production well has been drilled successfully and can generate electricity. However, the decision to apply the early or the stepwise strategy will depend on each developer and its interests. The first phases to develop a geothermal field can be costly and require millions of investment capital. At the same time depends on the success of drilling and the scientific experience of the team. Here, the stepwise strategy becomes a helpful method to keep the project cost at a minimum, obtain quick and good results, and contribute to developing the project sustainably and successfully.

Geothermal projects provide baseload energy that is cost-effective, based on proven technologies and low in emissions, contributing to the sustainable development goals of the United Nations. Since the reservoir capacity has been confirmed and the feasibility study finalised, the next step is to start the construction phase. The worldwide development of geothermal projects experiences severe barriers, and projects are delayed for years. These barriers are mainly high upfront investment costs, drilling risk and long development time. For these reasons, strategies are needed in each country to accelerate the developments and mitigate and distribute the risks. (Icelandic International Development Agency & Nordic Development Fund, 2013). Due to the long execution time for project development, geothermal is not the type of energy to contribute to solving any country’s energy supply in the short term, but must be considered in development country medium and long term.

2.2.1 The use of relatively small units to develop geothermal projects and their impact on the country energy matrix

Geothermal is considered one of the most stable and reliable baseload power sources at a relatively low cost. Installing more than one unit following the stepwise strategy for new geothermal projects in small countries or countries where the energy production depends on fossil fuels can contribute to the energy matrix flexibility. In El Salvador, the power generating facilities cover the national electricity demand according to the merit order list based on the energy cost reported from the producer to the national authority in charge of coordinating the national system. The following section presents how geothermal power plants in El Salvador affect the energy matrix behaviour during a scheduled shut down due to an overhaul. Figure 2-4 (UT, 2018) shows the energy matrix arrangement for June and September 2018. June represents the energy matrix with the geothermal power plants runing. Then, the effect of the shutdown a geothermal power plant and how the generation matrix is affected by an overhaul is shown in September.

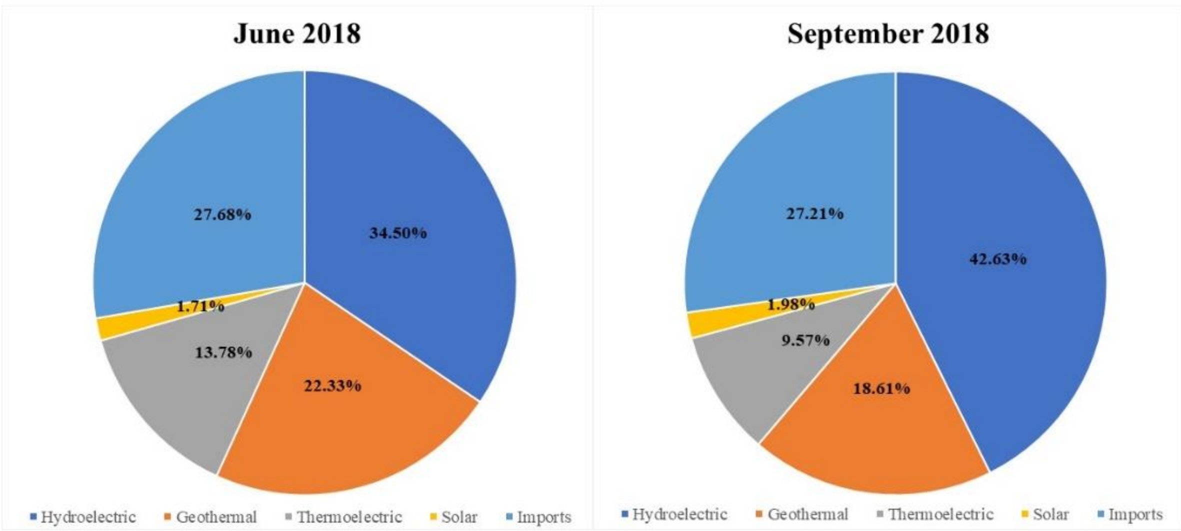


Figure 2-4 Generation share with all geothermal power plants connected to the national grid (June 2018) and generation share whit one geothermal power plant in overhaul (September 2018).

The Transaction Unit of El Salvador (UT) reports an overhaul in the Ahuachapán power plant for Unit 3 in September 2018. From Figure 2-4, this shutdown demand increased hydroelectric energy by 8.13% to supply the national demand compared with the generation share of June 2018. The flexibility in the matrix creates a reduction of thermal energy because the water reservoirs of the hydroelectric power plants have more capacity to generate electricity in this season of the year. For El Salvador, the effect of shutting down one geothermal unit (35MW) decreases the geothermal share by 3.71%. However, it is not increasing the energy price during the overhaul periods due to a strategic plan that schedules the geothermal maintenance activities during the high reservoir capacity period of the hydropower plants. As with geothermal energy, hydroelectric power plants are reliable baseload power at a low cost. Figure 2-5 confirms a reduction in electricity price due to the matrix flexibility during the overhaul of a geothermal unit. This is an example of how a stepwise strategy using relatively small units to develop geothermal can also contribute to the energy matrix flexibility to supply the country electricity demand at a low price.

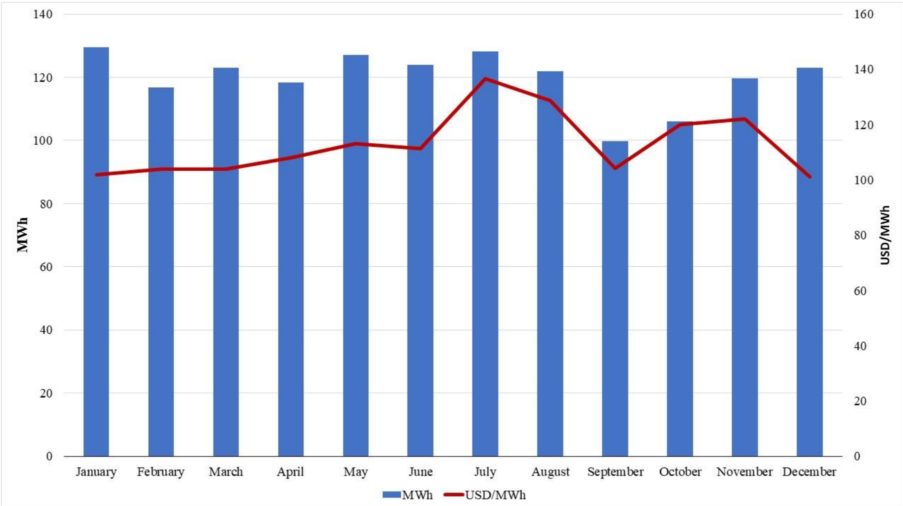


Figure 2-5 Geothermal Generation and electricity price in El Salvador (UT, 2018)

2.3 Feasibility studies

A feasibility study should provide all data necessary for an investment decision. The feasibility study is written to provide confidence with well explained and supported evidence of the project´s viability for both the developer and potential financier. The feasibility study does not need to provide all project data but should summarise the most relevant information and refer to the supporting documents that can be assessed for the financier or third party reviewer. A comprehensive appraisal of the project is often required for the financiers, and a third party specialist firm or consultant get involved.

2.3.1 The basic aspect of feasibility studies

The phases for developing a geothermal project, from the preliminary survey to the decommissioning phase, can also be presented, following the Manual for the Preparation of Industrial Feasibility Studies (MPIFS), in three stages related to the investment requirements: The pre-investment, the investment, and the operational stage (see Figure 2-6).

Complete knowledge of the phases is required to reduce the geothermal risk. Likewise, it is important to identify the role to be played by the different actors such as developers, investors, financial institutions, contractors, suppliers of equipment, consulting firms, and local communities.

The pre-investment stage needs all the developers' effort because the success of a geothermal project depends on the scientific, technical, economic findings and their interpretation. The cost of the phases for the pre-investment stage allows the best assessment of the project and might save considerable cost for the following stages due to the complex studies that are carried out to confirm the existence of a geothermal reservoir. Also, contribute to staying away from a superfluous feasibility study that would presumably have little chance of reaching the investment stage. Finally, it ensures that the project evaluation to be made by national or multilateral financing institutions becomes a more manageable task based on a well-prepared study.

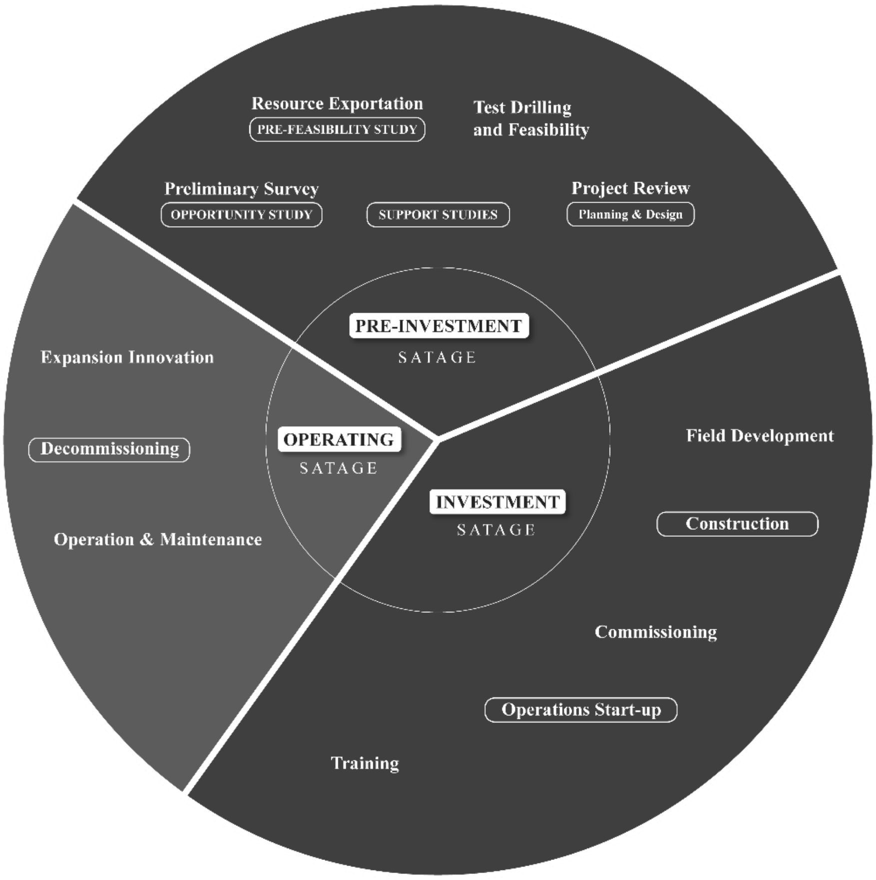


Figure 2-6 Arrangement of the geothermal development project according to the Manual for the Preparation of Industrial Feasibility Studies (MPIFS)

The feasibility study results from the commercial, technical, economic, and environmental prerequisites for a new geothermal project assessing the phases involved in the pre-investment stage. The result of these efforts is a project whose background conditions and aims have been clearly defined in terms of its objective, market share, reservoir production capacity, plant location, appropriate technology, and ESIA.

The final part of the feasibility study focuses on investment, including the production, operation and maintenance costs, sales revenues, and capital invested return. Furthermore, the study must be related to local taxes, laws, electricity market and production conditions, and this requires an analysis that has to be translated into costs, income and profits (Behrens & Hawranek, 1991).

2.3.2 Structure

Unfortunately, there is no guidance or pattern to follow to prepare project feasibility studies that include all industries. Moreover, the structure of the feasibility study varies from project to project, and the larger the project is, the more complex it will be, and more information will be required. Modifying the outline presented by the MPIFS, a typical structure to prepare a feasibility study for a new geothermal project is proposed as follows:

1. Executive summary
2. Project concept and background
3. Market analysis
4. Geothermal resource assessment
5. Project engineering and technology
6. Capital investment and operation costs
7. Technical staff requirements
8. Project execution plan and schedule
9. Financial assessment model

Recently, ESMAP has published a report to prepare feasibility studies for financing geothermal projects with an overview of the best practice focus to develop geothermal projects for electricity production (ESMAP, 2021). The structure proposed by ESMAP is similar to the MPIFS structure.

The presented structure is a guideline, and more information can be added, depending on the project progress. Based on the feasibility study and funding availability, a decision is made to continue or not with the project. All aspects of a feasibility report need to be updated as the project progresses and more information on the characteristics of the resources becomes available (GeothermEx Inc. & Harvey, 2013). As a starting point using the structure defined above, this thesis report will present the Technical and Feasibility Study for the San Vicente Geothermal Power Plant Project in El Salvador, Central America.

Chapter 3

Project concept and background

A feasibility study requires understanding how the project fits into the country electricity market share and the national frameworks. In the project concept and background of the feasibility studies section, the project is described, and the developer or the project owner is identified, together with the main reasons why the project needs to be developed. For instance, describing the project owner, project objectives, location, status, well data, reservoir capacity estimation, and studies completed are topics that might be included (Behrens & Hawranek, 1991).

3.1 Introduction to El Salvador geothermal development

El Salvador, a small country in Central America, has a surface area of 21,040 km^2 with a population of 6.3 million (DIGESTYC, 2013). El Salvador is located on the Pacific coast of Central America along the "Pacific ring of fire", where the Cocos and the Caribbean plates interact. The volcanic activity and seismicity associated with the plates are important for potential geothermal development in the country.

The geothermal interest in El Salvador starts with the first superficial surveys at the beginning of the 1960s. In 1975 the first power plant with 30 MW was commissioned in Ahuachapán until the plant facility reached 95 MW of installed capacity by 1981. El Salvador in the 1970s became the first country in Central America, the second in Latin America, and the eighth country in the world that utilised geothermal resources to supply the demand of electricity for its country. The current total geothermal capacity of the country is 204.4 MW and is distributed mainly in two geothermal fields: 95 MW in Ahuachapán and 109.2 MW in Berlin. Ahuachapán power plant has three units, two single flash condensing turbines with 30 MW each and one double flash condensing turbine with 35 MW. Berlin power plant has two single flash condensing turbines with 28.1 MW each, one single flash condensing turbine with 44 MW and one binary cycle power plant with 9.2 MW.

In 2004, SAN VICENTE 7 (a subsidiary of LAGEO S.A. de C.V.) received concessions for exploring and developing the San Vicente and Chinameca geothermal fields. Developing both fields is estimated to increase the geothermal installed capacity by 80 MW. At present, LAGEO S.A. de C.V. is the only geothermal company in El Salvador. The company has the concession rights to manage and utilise the geothermal resources for Ahuachapán, Berlín, Chinameca and San Vicente geothermal fields (Escobar, 2018).

The Transaction Unit (Unidad de Transacciones S.A. de C.V. – UT) reported electricity generation in March 2021 with a 572.1 GWh supply into the national grid. The generation from Ahuachapán and Berlín geothermal power plants was 121.3 GWh and supplied 21% of the total energy demand, mixed with power imports, hydro, thermoelectric, biomass, solar and wind power plants. The average market price was reported at 68 $/MWh after transmission losses and other charges (UT, 2021a). The location of geothermal fields in El Salvador are shown in Figure 3-1

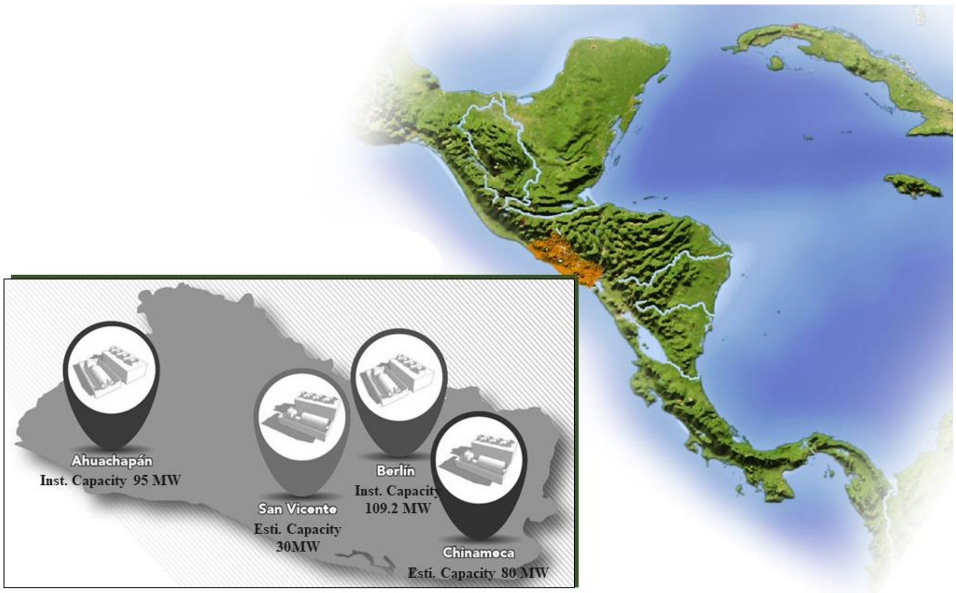


Figure 3-1 Geothermal fields in El Salvador, modified from (Escobar, 2018)

This thesis report will focus on San Vicente geothermal field, carrying out the Technical and Feasibility Study for the San Vicente Geothermal Power Plant Project in El Salvador, Central America.

3.2 San Vicente geothermal power plant project

3.2.1 Project owner

The Salvadoran electricity market was liberalised in 1996. As a result, the energy generation, transmission and distribution facilities were separated from the national electricity company CEL (Comisión Ejecutiva Hidroelectrica del Río Lempa). This change aimed to create a competitive market share where electricity prices would be regulated by supply and demand. As a result of this initiative, the energy generation, transmission, and distribution facilities were separated from CEL. In 1999 the geothermal fields and all their facilities were transferred to LAGEO, S.A. de C.V., the national distribution system and the thermal power generator were sold to international investors. Lastly, a new private company, called Empresa Transmisora de El Salvador (ETESAL), was created to operate the national energy transmission systems. This new market share promotes competitiveness and efficiency in the Salvadorean electricity market. At the same time, it creates a better investment scenario aimed towards the increase of the national power installed capacity, for example, the development of new geothermal energy projects.

During the 1980s, El Salvador stopped the geothermal projects due to a civil war and financial crisis, reinitiating the geothermal development with Berlín geothermal power plants project in 1992. San Vicente geothermal field was identified as one of the most promising reservoirs for electricity generation during the first geothermal survey in the 1960s carried out by CEL and United Nations experts. In 2004, the Superintendencia General de Electricidad y Telecomunicaciones (SIGET) gave concessions to SAN VICENTE 7 to explore, utilise and develop San Vicente geothermal field (Bundschuh & Alvarado, 2007; Herrera et al., 2010). As SAN VICENTE 7 is a subsidiary company of LAGEO S.A. de C.V., this thesis report will consider LAGEO S.A. de C.V. as the project owner.

3.2.2 Project objectives

According to the energy utilisation status, 91% of Salvadorian homes have access to electricity, locating El Salvador as the second country in Central America with a higher electrification index. In the National Energy Policy of El Salvador, the challenges to reduce the use of fossil fuels and promote renewable energy resources to warrant a reliable, stable, continuous, and quality electricity supply for the population at affordable prices are defined. Additionally, the policy promotes the reduction of the social and environmental impacts from new projects. To overcome these challenges, the National Energy Policy has six strategy lines that are strongly related: the diversification of the electricity market and promotion of renewables energy resources, strengthening the energy sector framework, protecting the final users and promoting a culture of efficiency and energy-saving, subsidies and social rates applications, innovation and technological development, and finally the integration to the regional electricity market (CNE, 2014).

The San Vicente power plant project has the main goal to utilise, in a sustainable way, the geothermal resource available in the field and contribute to increasing the renewable energy share in the electricity market. This objective fits with the first strategy of the National Energy Policy.

The project will evaluate different technologies available in the industry to select the most efficient and suitable design for the power plant, according to the geothermal reservoir characteristics. At the same time, the project will provide base load power at a low cost compared with the energy produced from fossil fuels in the country like thermoelectric power plants and imports that represented 27% of the energy supplied in the year 2020 (CNE, 2014; UT, 2020a).

The local communities surrounding the geothermal project area will receive social, technical and economic benefits with its development. The project will create permanent and temporary job opportunities and new small service businesses. Additionally, the municipality will have more funds to implement more social programs and local projects for the well-being of its inhabitants due to the taxes collected during the lifetime of the project.

3.2.3 Project status

The San Vicente geothermal project is located in the San Vicente state in the central part of the country, 60 km from the San Salvador capital city. The concession area is in the north flank of the Chinchontepec volcano and enclose five municipalities: San Vicente, San Cayentano Istepeque, Tepetitán, Verapaz and Guadalupe. Hydrothermal activities characterise the concession area confirmed by surface manifestations like soil thermal alteration, fumaroles and hot mud ponds. This concession area is 100 km^2 and can be positioned between the following Lambert coordinates: latitudes 283,000 - 271,000 and longitudes 512,000 - 523,000 (Montalvo & Guidos, 2010).

The resource exploration phase for the project was carried out from 2004 to 2007, where three exploratory wells were located and drilled, confirming a geothermal resource with an estimated temperature above 250°C. In 2009, the project owner contracted consultant services of Iceland GeoSurvey (ÍSOR) to review and evaluate all the project technical data obtained from the deep exploratory wells drilled. Four geothermal commercial-sized wells were drilled between 2012 and 2015 during the test drilling and feasibility phase. The testing results found that one of these wells can produce 7 MW, which encourages the company to continue with the drilling activities and the project phases (Gischler et al., 2017; Herrera et al., 2010; Pichardo, 2013a).

A clear gap of five years can be identified between the exploration period and drilling work. This gap was a milestone used to evaluate the first results and carried out complementary exploratory surveys to continue with the project considering the geothermal reservoir as a well-characterised geothermal resource ready to be developed to produce energy.

Chapter 4

Country electricity market status

Geothermal energy is one of the most stable and reliable baseload power sources at a relatively low cost. Developing a geothermal project using the country's natural resources allows the opportunity to diversify the electricity market share and reduce the risk of price rises due to the increase and variability of fossil fuel costs. One of the advantages of operating a geothermal power plant in a sustainable way is that once the power plant starts to generate, it will produce electricity for decades (Gehringer & Loksha, 2012).

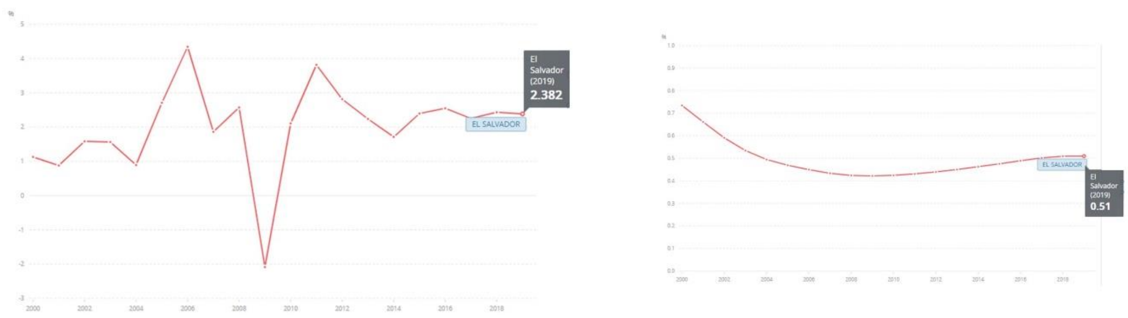
For El Salvador, it is important to develop the natural resources available in the San Vicente geothermal field to increase the renewable energy share in the electricity market. The electricity generated from this new power plant will be part of the base energy source that supplies the growth rate demand of the electricity. Furthermore, geothermal energy will share the market with new projects using variable renewable energies, like solar and wind, and projects with other technologies. In addition, the project owner needs to look for a long-term contract or a shared strategy between the different trading options in the electricity market to guarantee the project feasibility and reduce the risk of the fluctuation of electricity price due to its dependence on the oil prices. All this consideration will help the project owner and possible investor decide to continue the project.

During the preparation of a feasibility study is important to describe and understand the country electricity market status and how the market works to elaborate a complete analysis that includes all inputs from participants and stakeholders that interact with the project (Behrens & Hawranek, 1991). Within the feasibility reports, the country electricity market status should demonstrate that the market risk is sufficiently low to justify the project (Ingimundarson, 2021).

4.1 Country background

El Salvador, a small country in Central America, has a surface area of 21,040 km^2 with a population of 6.3 million (DIGESTYC, 2013). El Salvador borders Guatemala to the west, Honduras to the northeast, and the Pacific Ocean to the south. El Salvador is a high population density with approximately 300 inhabitants per km^2. The country allowed the circulation of the U.S dollar, and it has been the local currency with a fixed rate of 8.75 colones since 2001.

In El Salvador, in 2019, the annual gross domestic product (GDP) and the annual population growth were reported at 2.4% and 0.51%, respectively. However, the trend of these country indicators has been relatively steady in the last three years. Figure 4-1shows the values of these two country indicators for twenty years until 2019 (WBG, 2021a, 2021c).



a b

Figure 4-1 El Salvador annual trend for the population growth (a) and gross domestic product (b) from years 2000 to 2019

El Salvador has been progressing in its social and political development, expanding access to public services, including expanding electricity coverage and preferential rates for its inhabitants. However, despite the progress, the country faces challenges like natural disasters, environmental degradation, and climate change. For these reasons, the Presidency of El Salvador, through the Ministry of Foreign Affairs, is working to include in the national development strategy the 2010 Agenda for Sustainable Development (IRENA, 2020).

Recently, El Salvador had adopted cryptocurrency as an official currency besides the US Dollar and is mining bitcoin with geothermal energy (ThinkGeoEnergy, 2021). This scenario needs to be followed to see how much geothermal resources will be mining cryptocurrency, and how the country's electricity market will perform. Moreover, future researches on how cryptocurrency fits with developing geothermal projects need to be done.

4.2 El Salvador electricity market organisation and its institutional framework

El Salvador electricity market was liberalised in 1996 and is governed by the General Electricity Law and its regulation established in 1997. The Law and the regulations applicable to the electricity market commercialisation aim to promote competition between the companies that integrate the wholesale electricity market. These legal frameworks regulate the activities of generation, transmission, distribution and electricity commercialisation. Moreover, these frameworks apply to all entities developing these activities, regardless of whether they are public, mixed, or private.

The objectives of the General Electricity Law are, first, to develop a competitive market. Second, allow free access for the generation companies to the transmission and distribution facilities, with specific limitations being indicated by the Law. Third, the rational and efficient use of resources. Fourth, promote access to electricity for each social sector of the population. Finally, to protect the final user and the companies which are members of the wholesale electricity market (ZUMMARATINGS, n.d.). The companies which are members of the wholesale electricity market are shown in Figure 4-2, and they are from the public and private sectors.

The following organisations form El Salvador's electricity market institutional framework:

1. The National Energy Council (CNE) is the regulatory authority on energy policy and is responsible for defining energy regulations. The CNE is also

responsible for defining the country’s short, medium, and long-term strategies

2. The Transaction Unit (UT) is a private corporation created under the General Electricity Law. Its functions are the administration of the wholesale market and the operation of the electric power system and its international interconnection within the Central America region
3. The General Superintendence of Electricity and Telecommunications (SIGET) is the authority for applying laws and regulations that govern the electricity sector. SIGET’s functions are to supervise the development and behaviour of the electricity market, regulate charges for transmission and distribution system uses, regulate UT charges, and publish statistical data from the sector
4. The market participants (Participantes del Mercado – PM) are the national and private generators, the Transmission Company of El Salvador (ETESAL), the electricity distributors, electricity marketers agents and the large-scaled final users (CNE, 2021; CNE & PROESA, 2016; SIGET, 2020; UT, 2020b)

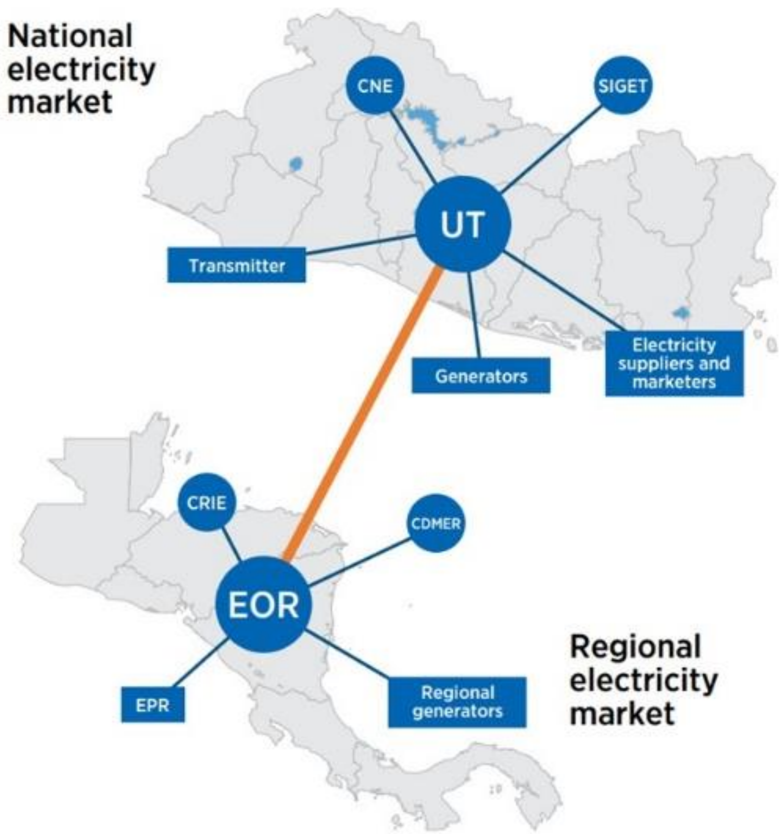


Figure 4-2 Wholesale electricity market structure modified from (IRENA, 2020)

The following organisations form the regional electricity market institutional framework:

1. Dean Council of the Regional Electricity Market (Consejo Director del Mercado Eléctrico Regional – (CDMER)) is the organisation responsible for facilitating the relationship between the Regional Electricity Market (MER) participants. The CDMER is constituted by the CNE and the ministers of energy of the Central American countries
2. The Regional Electric Interconnection Commission (Comisión regional de Interconexión Eléctrica – CRIE) is the regional regulator in charge of

administrative protocols, regulations, and other complementary instruments to ensure transparent competition and efficiency for the operation of the MER

3. The Regional Operating Entity (Ente Operador Regional – EOR) is the organisation in charge of the market administration and the planning and operation of the MER
4. The Enterprise Owner of the Regional Electric Network (Empresa Propiestaria de la Red – EPR) is constituted by the public entities of the Central American countries. These entities are stockholders of the Central American Electricity Interconnections System (Sistema de Interconexión Eléctrica de los Países de América Central - SIEPAC) network, with the main objective of developing, designing, building, and operating the regional grid lines
5. The regional markets also include regional generation companies and other market participants (CNE & PROESA, 2016)

4.3 The evolution of electricity generation in El Salvador

Since the market liberalisation in 1996, El Salvador has highly depended on thermal power generation, followed by hydropower and geothermal energy. As shown in Figure 4-3, the country total installed capacity had reached 2 Gigawatts (GW) in 2020. Additionally, by 2017, the installed power capacity increased due to ANTARES new solar power plant with 60 MW and the 5 DE NOVIEMBRE hydropower plant expanded by 80 MW. However, the thermal capacity has been slightly increasing and is still the largest power supply used in the country.

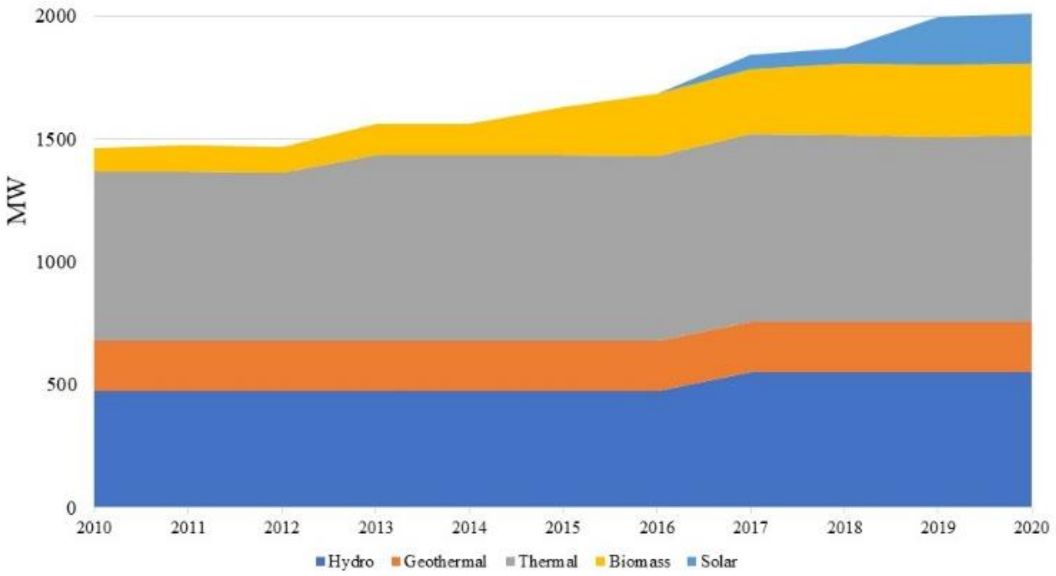


Figure 4-3 Total installed capacity by source from 2010 to 2020 (SIGET, 2021a)

The installed power capacity by sources for the year 2020 is shown in Figure 4-4, where conventional thermal power source contributes 37.63%, followed by hydropower with 27.47%, biomass with 14.59%, geothermal with 10.16%, and solar with 10.14%. Since 2016, solar energy using photovoltaic (PV) technology has started to grow and has reached 204 MW in 2020. The total energy capacity is expected to grow in the coming years with the PV, wind, and geothermal projects.

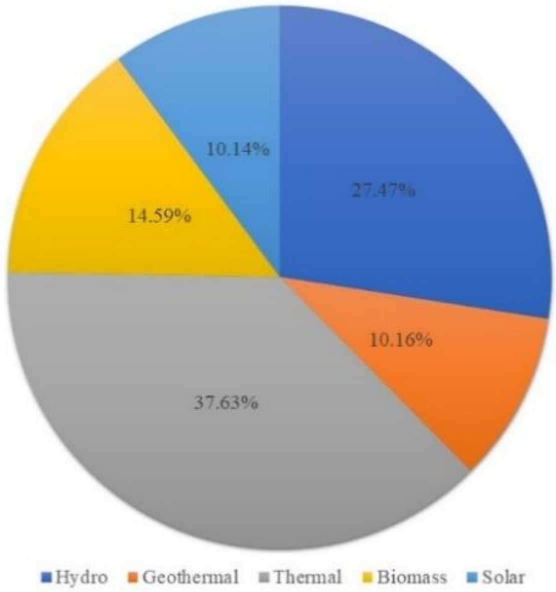


Figure 4-4 Installed power capacity by source, the year 2020

Figure 4-5 shows the electricity evolution between 2010 and 2020. During this period, geothermal energy has been observed without any change and has maintained an average generation of 1,435 gigawatt-hours (GWh). Solar generation has been increasing on average 40 % every year since 2017, and it reported at the end of 2020 with 498 GWh. In November 2020, the first wind farm with 15 wind turbines of 3.6 MW each, named Ventus, started its commissioning period of 4 wind turbines and had injected into the wholesale market 14 GWh (UT, 2020b; Wind farms, 2021). Finally, during this period, the domestic generation has been affected due to growing electricity imports, most of which come from Guatemala (IRENA, 2020). The imports are slightly decreasing due to the growth of renewable energy in the electricity market share.

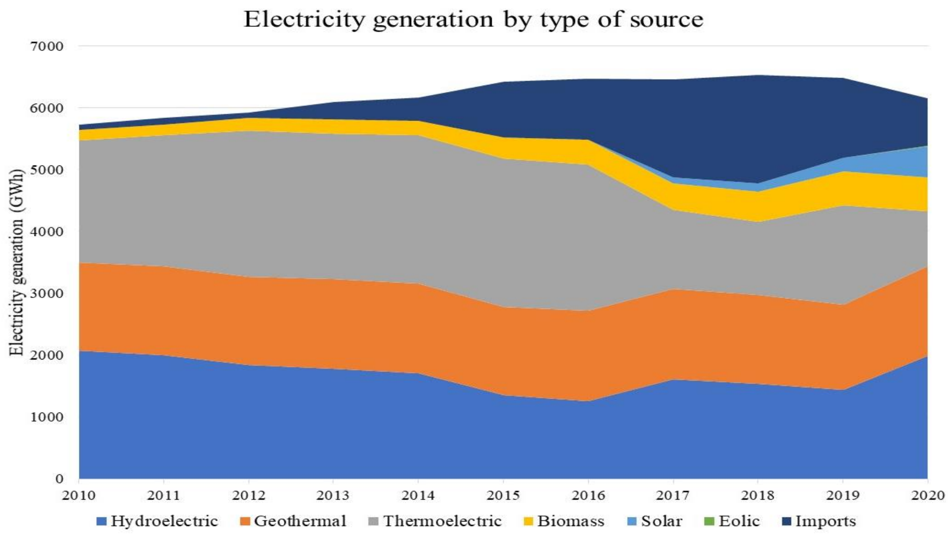


Figure 4-5 Electricity generation by type of source from 2010 to 2020 (SIGET, 2021a)

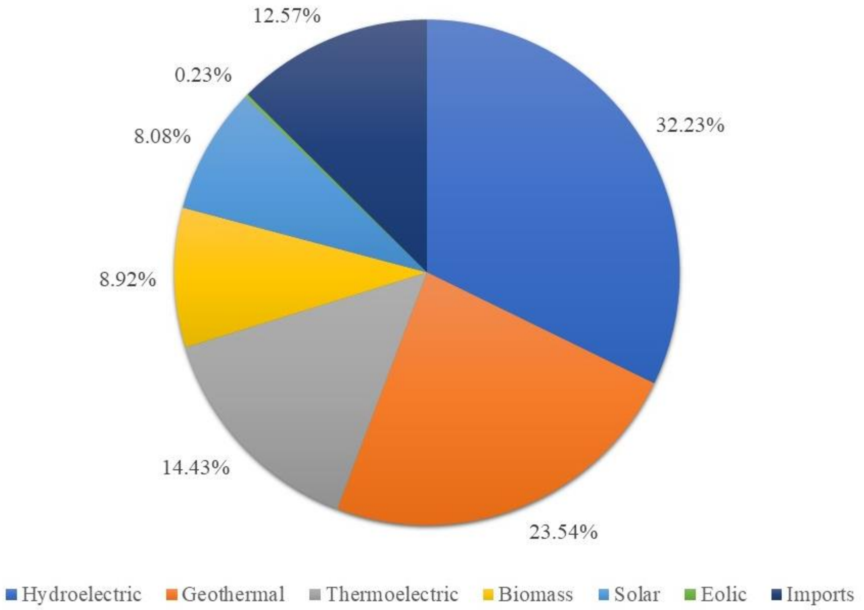


Figure 4-6 Annual electricity generation by type of source, the year 2020

The breakdown of electricity supply by generation source in 2020 with 6,160 GWh is shown in Figure 4-6. This year the first wind-produced gigawatts-hours were sold in the electricity market. Additionally, this breakdown of the electricity matrix and the previous figure place hydropower and geothermal energy as the basis of electricity generation. However, it is clear how the market share includes renewable electricity sources to reduce the use of fossil fuels to generate electricity for the country.

4.4 Geothermal power generation history in El Salvador

In El Salvador, geothermal has been one of the main sources of electricity since 1975, when the first power unit started operations in Ahuachapan. Today the country has a competitive wholesale market, and geothermal provides 24% of the electricity demand in the country, which is one of the highest worldwide (Herrera et al., 2010). The total geothermal capacity installed reached 204.4 MW in 2008 and remains the same today.

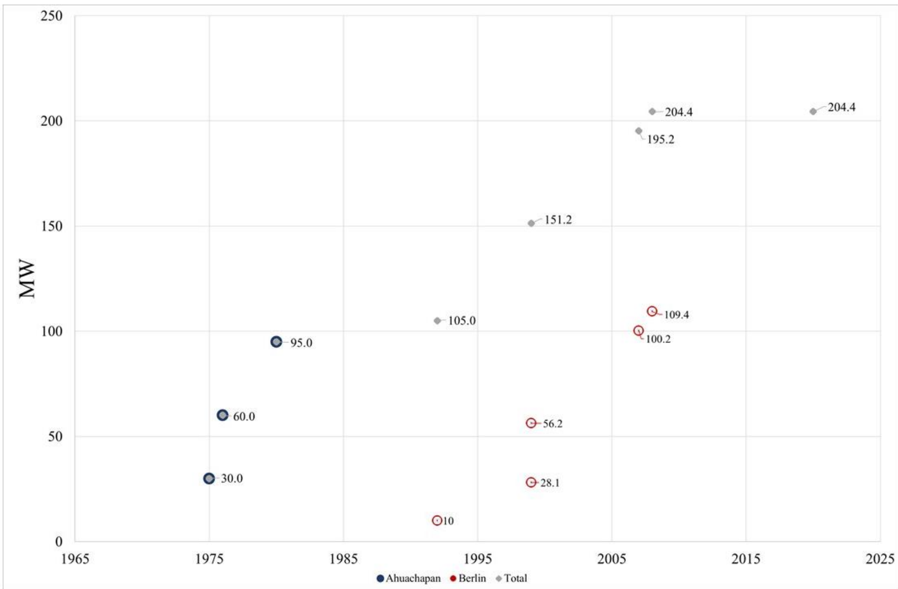


Figure 4-7 El Salvador geothermal capacity generation history

Figure 4-7 shows the historical development of the installed capacity for both geothermal fields and the total installed capacity from 1975 to 2020. The next developing plans for LAGEO are the second bottoming Organic Rankine Cycle (ORC) binary power plant that is under construction in Berlín geothermal field with 8 MW of capacity (TURBODEN, 2019) and the development of San Vicente and Chinameca geothermal fields (Escobar, 2018). Developing these three projects is estimated to add 88 MW of renewable energy to the electricity market share using the country's geothermal resource in the nearest future. The total installed capacity of the country is foreseen at about 290 MW (Bertani, 2010).

4.5 The national electricity transmission system

The El Salvador transmission system is owned by ETESAL, a state-owned company, and is responsible for maintaining and expanding the transmission system.

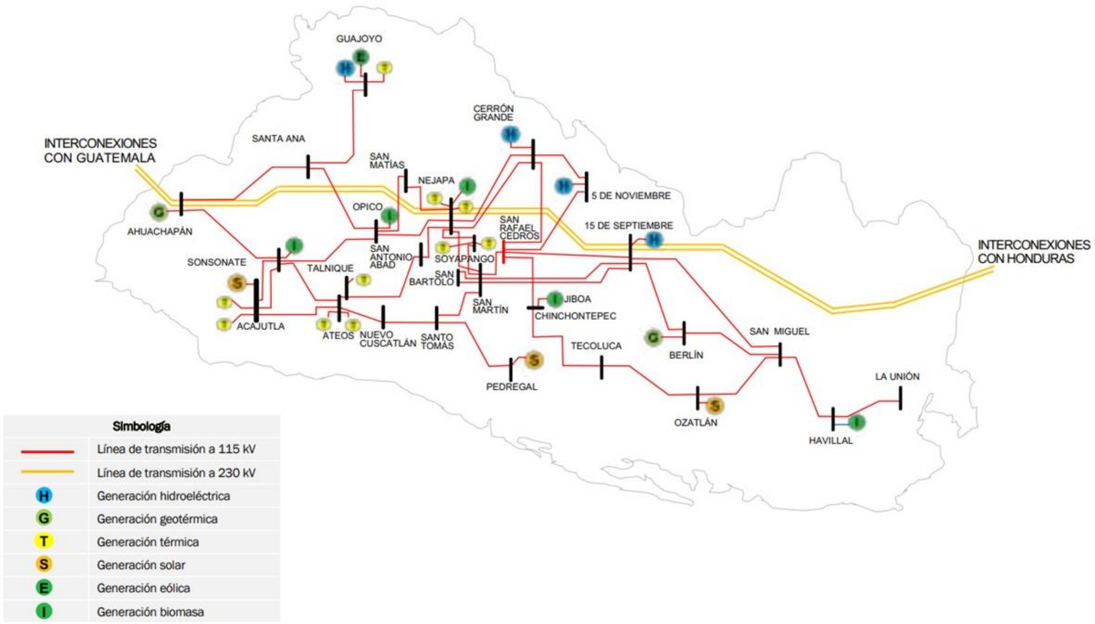


Figure 4-8 El Salvador transmission system (UT, 2020b)

Figure 4-8 shows the entire national transmission system, including interconnection with Guatemala and Honduras. The internal transmission system is 1,073 km long with 41 lines at 115 kV, 24 power substations, and 4 lines at 230 kV that also serve the interconnection with Guatemala and Honduras as part of the SIEPAC. The UT manages the country electricity market and is responsible for the operation of the transmission system (UT, 2021b).

4.6 Regional interconnections system

The EPR owns the regional transmission system (SIEPAC) that connects, emerging from bilateral agreements between, El Salvador, Guatemala, Nicaragua, Honduras, Costa Rica, and Panama. The Treaty of the Electricity Market of Central America, once it was reviewed and signed by the SIEPAC country members, became the legal base to create the regional electricity market (MER) with its regulatory (CRIE) and operation (EOR) institutions (EOR, 2021).

Figure 4-9 shows the connection between the SIEPAC countries and presents the electricity transactions on May 28th, 2021, at 11 am, confirming El Salvador as one of the most active countries importing electricity from the Central America region. The electricity demanded at that time was 723 MW, and the country decided to import from the regional market 173 MW from Guatemala and 131 MW from Honduras due to the competitive electricity cost of the regional market. At the same time, to cover the electricity demand, the country generated 424 MW from the local companies.

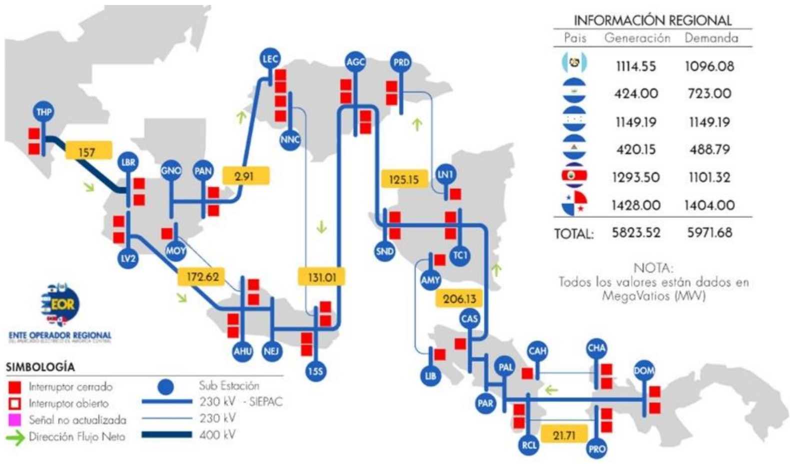


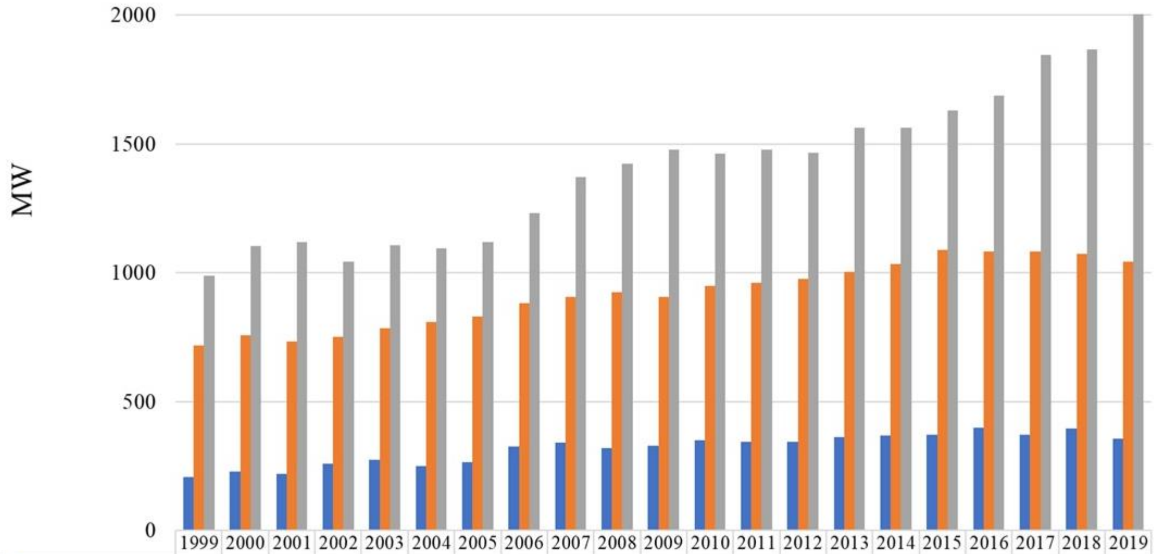
Figure 4-9 Regional electricity market – SIEPAC (EOR, 2021)

The electricity transaction between the countries can be done using the spot market, bilateral agreements or non-firm contracts depending on the surplus of each country (IRENA, 2020). In its National Energy Policy, El Salvador promotes renewable energies to reduce fossil fuel consumption and is looking to increase electricity trading in the regional system for the nearest future.

4.7 El Salvador electricity demand

The evolution of electricity demand from 1999 to 2019 is shown in Figure 4-10. The average annual growth rate in demand is 2%, and the average annual growth rate of power installed capacity is 3%. The installed capacity has increased in order to cover the annual electricity demand.

The difference between installed capacity and maximum demand values is given by the nominal capacity and the reliability of generation. El Salvador electricity market relied on thermal power generation. At present, most of the thermoelectric units are used as a backup for other technologies, especially for variable renewable energy generators like solar and wind. At the same time, thermal electricity is sometimes costlier than importing electricity within the regional market (IRENA, 2020).



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Minimum demand	207	227	219	260	273	250	265	327	341	320	329	351	345	344	362	368	371	400	372	397	357
Maximum demand	718	758	734	752	785	809	829	881	906	924	906	948	962	975	1004	1035	1089	1081	1081	1072	1044
Installed capacity	989	1103	1118	1044	1106	1096	1119	1231	1372	1422	1477	1461	1477	1466	1562	1563	1629	1686	1844	1868	2002

Figure 4-10 Maximum and minimum growth rate of electricity demand

4.8 Installed capacity expansion plans

In 2020 two new power generators joined the electricity market share. The first one is the photovoltaic solar power plant named “ESCOLAR I”, which has an installed capacity of 10 MW. The second one is the first wind farm in El Salvador, named “VENTUS”, with an installed capacity that will be 54 MW with 15 wind turbines of 3.6 MW each upon completion (UT, 2020b). Table 4-1 shows the list of new power plants planned to increase the country’s installed capacity in the following years. The first power plant using liquefied natural gas (LNG) is scheduled to start its operation by June 2022, with 378 MW, representing 68% of the 554 MW planned increase.

Increasing the market share of these renewable projects contributes to offering more affordable electricity prices to households, businesses, and institutions. Furthermore, it is also expected to increase competitiveness in industries like manufacturing and services, attract foreign investors, improve local infrastructure and create permanent jobs, contributing to the country’s economic growth. At the same time, these projects will displace the thermal generation that depends on fossil fuel and reduce the imported electricity. These positive impacts apply to the new projects, but their higher installed capacity is strongly tied with the LNG power plant. The LNG power plant will help El Salvador manage the unpredictable hydropower generation during the dry seasons and prolonged droughts due to climate change’s impacts (IFC, 2021). Finally, once all these projects increase the country’s installed capacity, El Salvador will possibly export energy to countries in the region through the regional system SIEPAC.

Table 4-1 Projects under construction (SIGET, 2021b)

Project Name	Project owner	Source type	Installed capacity (MW)
Energia del pacifico	Planta EDP	LNG	378
El Chaparral	CEL	Hydropower	66
Ventus	Ventus S.A. de C.V.	Eolic	54
Chinameca	San Vicente 7 Inc.	Geothermal	25
San Vicente	San Vicente 7 Inc.	Geothermal	10
Binary Cycle II Berlín	LAGEO S.A de C.V.	Geothermal	5
Escolar S.A. de C.V.	Escolar I	Solar	10
Imfica Industrial	Imfica Industrial S.A de C.V.	Solar	2
Potenza	Potenza S.A. de C.V	Solar	2
Gerardo Barrios Univers	Gerardo Barrios University	Solar	1
Agrocampestre	Agrocampestre S.A. de C.V.	Biogas	1
Reing	Reing S.A. de C.V.	Biogas	1
		Total	554

4.9 Performance of the electricity price

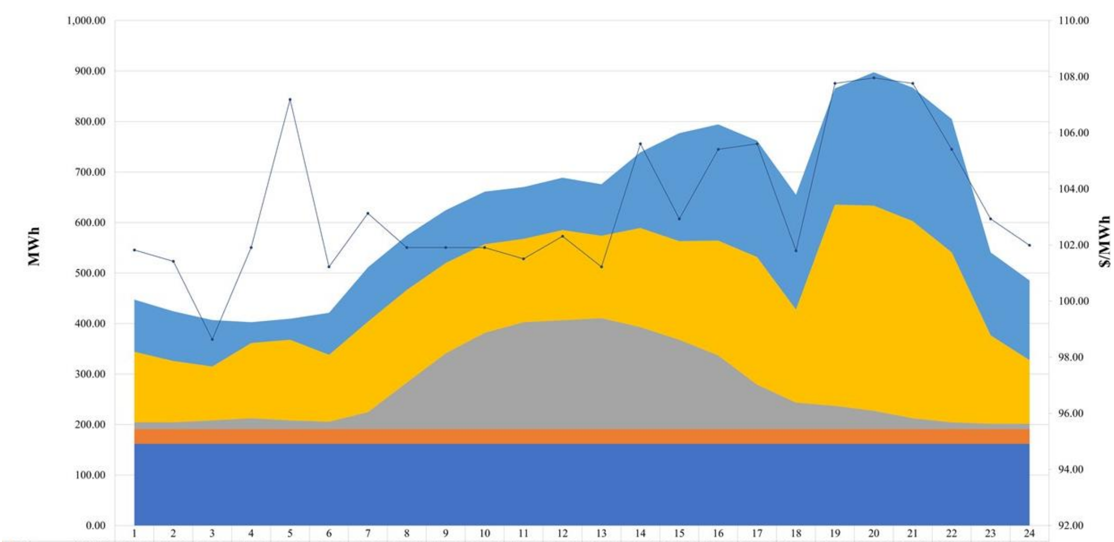
The Transmission System and Wholesale Electricity Market Operation Based on Production Cost regulation (Reglamento de Operaciones del Sistema de Trasnmision y del Mercado Mayorista Basado en Costos de Produccion – ROBCP) guaranteeing transparency in the operations of the electricity market, providing clear rules, procedures, and free competitions between its participants.

The ROBCP regulated how to dispatch the power generation units sorted in a list of merit in ascending order based on their variable production costs for each generator. The energy supply payment depends on the lower variable cost of the unit that is called to cover the demand during the day in the spot market. The last unit to be dispatched established the Marginal Operation Cost (Costo Marginal de Operación –CMO). Additionally, the demand side pays system costs (SC) that correspond to the following activities: SIGET registry update, transmission system usages, wholesale market administration, transmission losses, marginal costs compensations, and international transactions complements. The average system cost for the last 24 months ending in April 2021 was 12.92 USD$/MWh (Arenivar et al., 2021; CNE & PROESA, 2016; UT, 2021b).

The ROBCP also establishes a capacity payment (CP) to the power generators, a proportional payment to the capacity of each unit can guarantee in a critical supply scenario. Additionally, the firm capacity to be paid is the initial firm capacity adjusted according to the maximum system demand, with the same proportion for all participants and is set at 7.8 USD /kW-Month, and it is revised annually (CNE & PROESA, 2016).

The UT coordinates the payment to the generators adding the payment by the energy generated and injected into the electric system that corresponds to the CMO plus the system cost (SC). These payments correspond to the spot market price (MRS price = CMO + SC). The capacity payment is adding to the MRS and is known as Monomic price (MP). The MP is the total amount equivalent to a single price for the sale or purchase of electricity in the wholesale market (MP = MRS + CP) (UT, 2011).

Figure 4-11 shows the daily generation supplied to cover the hourly country demand on May 25th, 2021. Additionally, this figure shows the CMO from the merit list of the last unit that was dispatched. A thermoelectric generator determined the CMO on May 25th during the whole day. At the same time, the figure shows the geothermal source as the base electricity supplier.



	1	2	3	4	5	6	7	8	9	10	11	12
Hydropower [MWh]	103.11	98.48	91.76	41.53	41.53	83.26	107.60	107.60	104.40	104.06	102.51	103.69
Thermalpower [MWh]	139.67	121.31	106.95	149.08	159.69	132.43	179.38	183.52	178.84	175.77	165.05	178.68
Renewaable [MWh]	13.75	13.75	17.33	21.42	17.33	14.85	33.64	92.50	150.38	190.57	211.89	215.55
Biomass [MWh]	29.13	29.13	29.13	29.13	29.13	29.13	29.13	29.13	29.13	29.13	29.13	29.13
Geothermal [MWh]	161.71	161.71	161.71	161.71	161.71	161.71	161.71	161.71	161.71	161.71	161.71	161.71
CMO [$/MWh]	101.82	101.42	98.63	101.91	107.19	101.22	103.13	101.91	101.91	101.91	101.51	102.31

	13	14	15	16	17	18	19	20	21	22	23	24
Hydropower [MWh]	101.96	149.60	213.91	230.16	230.16	227.31	230.16	264.12	264.12	264.12	164.09	157.87
Thermalpower [MWh]	162.98	196.53	195.11	227.50	252.76	184.23	398.70	406.20	390.75	336.43	175.10	125.80
Renewaable [MWh]	219.99	202.10	177.27	146.07	88.32	52.71	45.97	36.44	21.42	13.75	10.71	10.71
Biomass [MWh]	29.13	29.13	29.13	29.13	29.13	29.13	29.13	29.13	29.13	29.13	29.13	29.13
Geothermal [MWh]	161.71	161.71	161.71	161.71	161.71	161.71	161.71	161.71	161.71	161.71	161.71	161.71
CMO [$/MWh]	101.22	105.61	102.93	105.41	105.61	101.79	107.76	107.96	107.76	105.41	102.93	101.99

Figure 4-11 Daily generation load profile by source and the CMO for May 25th, 2021 (UT, 2021b)

Figure 4-12 shows the 56 power units that structure the electricity market in El Salvador and their merit list used to define the hourly marginal cost. The cost of the electricity imports and the renewable energy sources like solar, wind, and biomass had reported its CMO at 0 USD/MWh. Additionally, the average CMO reported for geothermal generators is 4 USD/MWh, for hydropower generators it is 80 USD/MWh, and for the thermoelectric generator it is 124 USD/MWh.

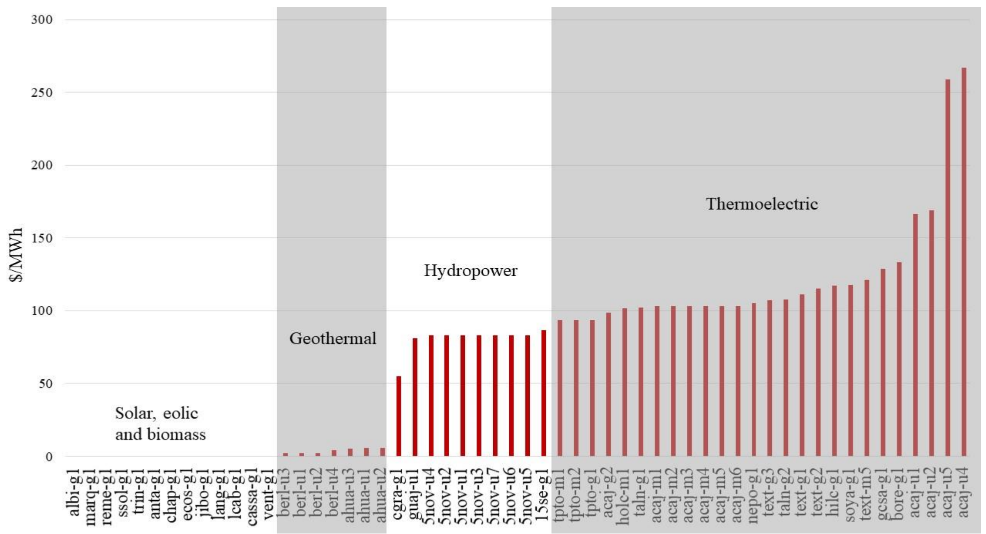


Figure 4-12 Generators merit list order for May 25th, 2021 (UT, 2021b)

Figure 4-13 shows the annual MRS price behaviour during the last 24 years with an average of 103 USD/MWh. Electricity prices in El Salvador depend on the international oil price due to the thermoelectric generation using fossil fuels and how they are considered to establish the CMO. At the same time, the water value, which is the opportunity cost of using water to dispatch hydropower units or store them for future utilisation, also affect the CMO.

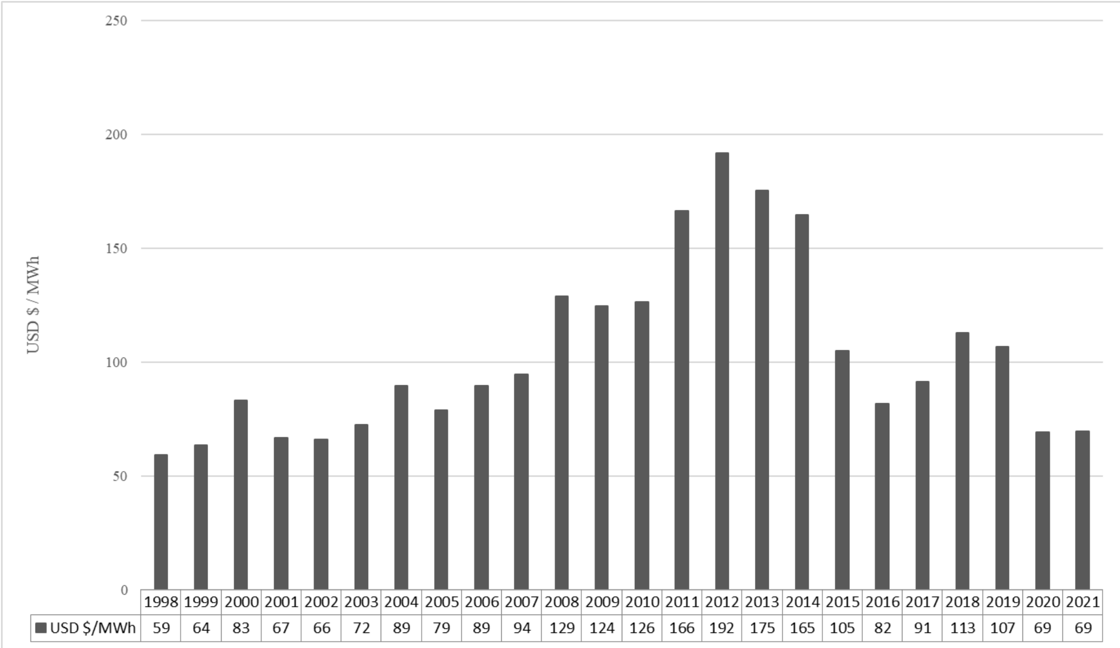


Figure 4-13 Historical electricity MRS price (SIGET, 2021a; UT, 2021b)

In 2011 the electricity price increased due to the sustained high price levels in the international oil market. The spot price of Brent was reported on average at 111.26 USD/barrel, making it the first time the global price average was more than 100 USD/barrel (EIA, 2012). In 2015, the electricity price decreased again, likewise associated with the decrease in oil price; the spot price of Brent was reported on average at 52 USD/barrel (EIA, 2016).

The electricity generation expansion plan carried out by the CNE estimate that the electricity price will be lower by incorporating the new renewable projects and the LNG plant into the market share, stabilising an average price of 90 USD/MWh (CNE, n.d.).

Energy transactions in the El Salvador wholesale electricity market can be done using Long Term Contracts (LTC), Bilateral Contracts (BC), and through the spot market (Mercado Regulador del Sistema – MRS). In El Salvador, the LTC have the same structure as a Power Purchase Agreement (PPA) (CNE & PROESA, 2016).

4.10 Tax incentives

The Law of Fiscal Incentives for the Promotion of Renewable Energies in Electricity Generation states that for projects up to 20 MW, there is a ten year payment exemption on import tariff duties for machinery, equipment, materials, and supplies meant exclusively for the pre-investment and investment phase of the construction works for the power plant, including the power transmission lines. Additionally, there is a payment exemption on income taxes for five years for projects between 10 and 20 MW and ten years for projects up to 10MW of capacity. Lastly, total tax income exemption is derived from the sale of

Certified Emissions Reductions (CERs) under the Clean Development Mechanism (CDM) or other carbon markets (Decreto Legislativo N°462, 2007).

The main takeaways from this chapter to help the project developer to understand and identify any risk for the project are:

- For El Salvador, it is important to develop the natural resources available in the San Vicente geothermal field to increase the renewable energy share in the electricity market
- The electricity generated from this new power plant will be part of the base energy source that supplies the growth rate demand of the electricity
- The institutional framework, laws and regulations applicable to the electricity market commercialisation aim to promote competition between the companies and free access to the transmission facilities. These frameworks apply to all entities developing these activities, regardless of whether they are public, mixed, or private
- The national transmission system, which includes interconnection with the neighbour country, allows commercialisation through the SIEPAC system.
- Geothermal energy will share the market with new projects using renewable energies, like solar and wind, and projects with other technologies
- Electricity prices in El Salvador depend on the international oil price due to the thermoelectric generation using fossil fuels and how they are considered to establish the CMO
- The performance of the electricity market based on the ROBCP regulated how to dispatch the power generation units sorted in a list of merit in ascending order based on their variable production costs

In conclusion, the El Salvador eletricity market has clear and strong frameworks, regulations, and laws to develop the electricity market. However, the electricity price based on the production cost is forecast to establish an average price of 90 USD/MWh due to the new renewable projects and the LNG plant operating in 2022.

Finally, two recommendations can be addressed for this project. The first is to look for the most suitable power contract agreement in the market to guarantee the project feasibility and reduce the risk of electricity price fluctuation, and the second is to register the project at the national institutions to take advantage of the country tax incentives.

Chapter 5

Geothermal resource assessment

Geothermal projects involve theoretical and numerical analysis combined with practical procedures based on experience to create the conceptual models and design criteria as initial steps. Groups of scientists and engineers contribute to understanding the resource heat available in a geothermal area and the ways it can be utilised (DiPippo, 2016b).

The feasibility study prepared for a geothermal project includes the proof of reservoir capacity throughout the validation of detailed information of the proposed exploitable area. The components of the data available need to be well organised and presented in this section. The feasibility study should overview the viability of a geothermal reservoir, the location, size, depth, quality, composition, horizon of the project, and its estimated power generation capacity (Behrens & Hawranek, 1991; Ingimundarson et al., 2021).

The main components of the geothermal project that should be included in this section are the conceptual model, including the geothermal system exploratory history, the proven capacity at the well head of drilled wells, the reservoir estimated generation capacity, and the strategy to follow for the field development (Ingimundarson et al., 2021).

5.1 Conceptual model of San Vicente

The conceptual model must respect and be consistent with all known information and be of sufficient detail to allow the first-pass estimate of resource temperature and size. As an important rule, the approach of how the magnitude and nature of uncertainties about key conceptual model parameters are presented should be clearly published to potential financiers (IGA & IFC, 2014). The following section presents and integrates the exploration data for the San Vicente geothermal field into a conceptual model.

5.1.1 Geothermal system exploratory history

Once the most prospective area of the project was identified, geological surveys and the drilling plan proceeded to aim for the confirmation of the geothermal reservoir, its nature, and heat distribution. The first two wells were drilled in 1979, confirming a geothermal reservoir with a temperature above 200°C, as is going to be presented in the following sections. The project owner continued the exploration surveys in 2005 and drilled three more exploratory wells from 2006 to 2007, confirming a geothermal reservoir with temperature and low permeability. After these results, the project owner studied with more detail the data available and continued with the exploration surveys, resulting in new drilling targets aiming at geological structures with better permeability. As a result of this new study, four additional wells were drilled from 2012 to 2015, finding higher temperatures and better permeability.

An update of the geochemical study was carried out in 2005. The study covered 53 samples from cold water and 22 from hot water springs, 22 water domestic wells, three rivers, and two fumaroles (LAGEO, 2020). In addition to the surveys carried out for San Vicente geothermal project before 2005, complementary geophysical surveys were conducted from 2005 to 2015. The surveys included magnetic, Head On, and gravimetric. Also, seismic monitoring studies and complementary electromagnetic (MT/TDEM) surveys were included.

5.1.2 Geotectonics and structural geology

Most of the geothermal projects are located at plate boundaries due to the strong correlation between heat and plate tectonic settings. Divergent and convergent plate boundaries are related to volcanic activity, high heat flow, and stress patterns that are promising for the development of high-temperature geothermal reservoirs. Moreover, high-temperature geothermal reservoirs are also located along complex continental plate boundaries, with their associated volcanism. Generally, the geothermal reservoirs are located in geological environments that require surveys and studies to create a realistic conceptual model (DiPippo, 2016a).

The San Vicente geothermal field is located on the northern flank of the Chinchontepec volcano. It is located south of the San Vicente segment of the El Salvador fault zone (ESFZ), between Ilopango Lake and Lempa River. To the north, it is limited by the characteristic escarpment of the normal fault with a dextral component; and to the east, by a fault system mainly to the NW-SE with a vertical component. To the south and southeast, by a fault system approximately to the E-W with a horizontal component, corresponding to the western end of the pull-apart basin of the Lempa River (intersegmental zone of the Lempa River), as is shown in Figure 5-1 (LAGEO, 2020). The geothermal project area is located within the most active zone of the country. The tectonics are related to regional forces associated with the subduction of the Cocos Plate beneath the Caribbean Plate (Pichardo, 2013b).

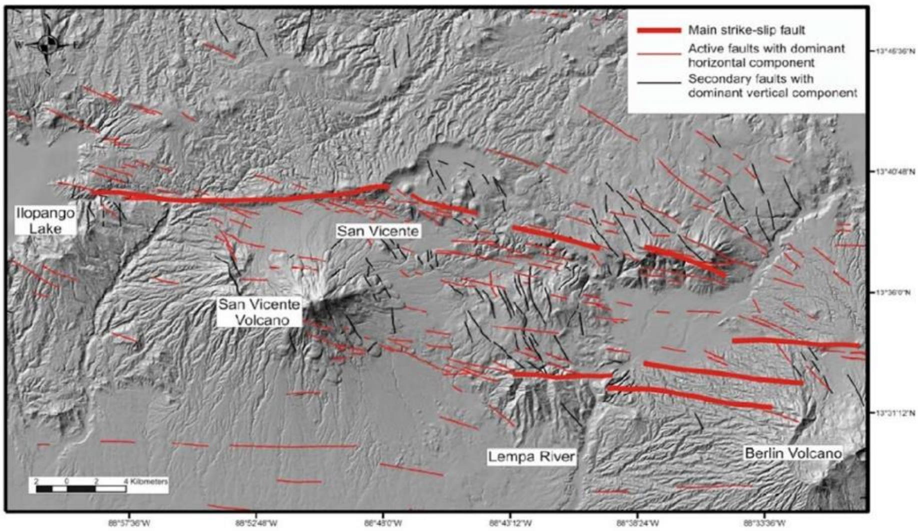


Figure 5-1 Location and faults of San Vicente geothermal field in El Salvador fault zone (ESFZ)

5.1.3 Stratigraphy

The local stratigraphy of the San Vicente geothermal project is based on the geological map created by the German Mission in 1978 and the geological mapping carried out by the project owner in 2005. Additionally, some of the data presented were observed in the cutting samples during the drilling work (LAGEO, 2020). The San Vicente volcano is an andesitic, composite volcano, the second most voluminous in El Salvador, occupying 130 km^3. The most recent activity of this complex is dominated by effusive volcanic eruptions, moderately fluid magma, and low gas content. A dacitic dome was identified and located in the west cone of the San Vicente volcano, suggesting a shallow magmatic chamber (Pichardo, 2013b). Figure 5-2 shows the mapped geological units for the San Vicente geothermal project, and Table 5-1 presents the units organised from the oldest to the most recent.

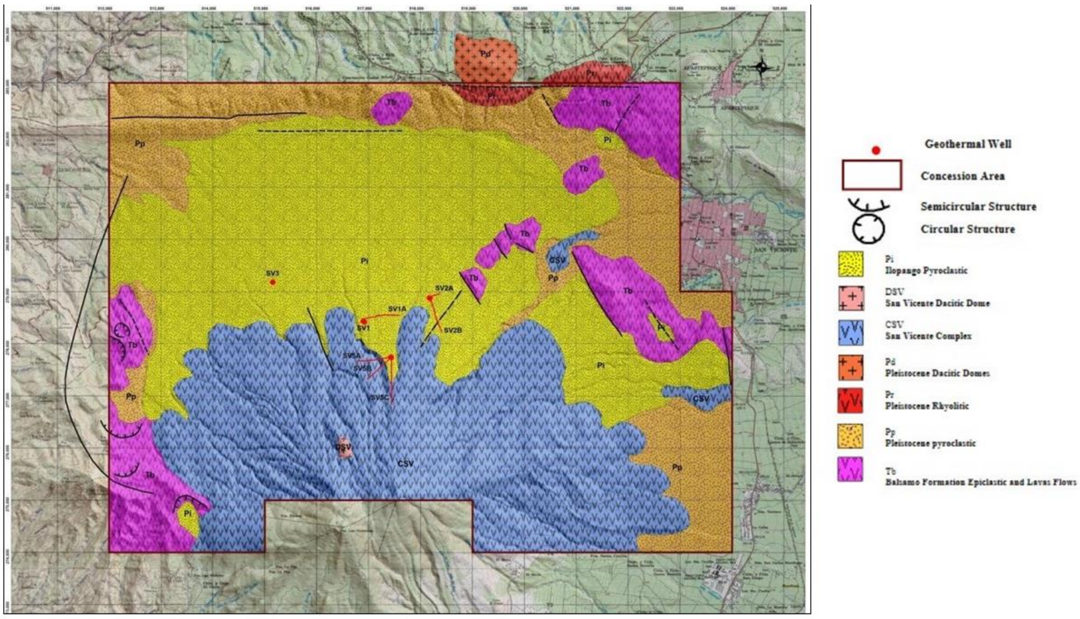


Figure 5-2 Geological maps of San Vicente geothermal project (Modified from Pichardo, 2013)

Table 5-1 Geological units of San Vicente geothermal project (Pichardo, 2013b)

Item	Geological Unit	
1	Lavas and epiclastites of the Bálsamo Formation - Pliocene	Tb
2	Pleistocene Pyroclastites	Pp
3	Pleistocene rhyolites and ignimbrites	Pr
4	Pleistocene Dacitic Domes	Pd
5	San Vicente Complex	Csv
6	San Vicente Dacitic Dome	DSV
7	Recent Pyroclastic Flow Deposits	Pr
8	Ilopango pyroclasts	Pi

5.1.4 Borehole geology

The data of the wells drilled to date for the San Vicente geothermal project is presented in Table 5-2. The depths of these wells range between 860 m and 2,250 m (measured or vertical depth).

Table 5-2 Characteristics of the San Vicente project wells drilled (LAGEO, 2020)

Borehole identification	Type	Drilled date	Depth (m)	Liner diameter (in)
SV-1	Vertical	1979	1346 TVD*	7 5/8
SV-1A	Directional	2006	2539 MD**	7
SV-2A	Directional	2007	1331 MD	7 5/8
SV-2B	Directional	2015	1550 MD	9 5/8
SV-3	Vertical	2007	860 TVD	13 3/8
SV-5A	Directional	2013	1785 MD	9 5/8
SV-5B	Directional	2013	1843 MD	9 5/8
SV-5C	Directional	2015	2250 MD	9 5/8

TVD* = Total vertical distance MD** = Measure distance

The San Vicente geothermal project wells have mineralogical alteration assemblages in line with a high-temperature geothermal reservoir. The alteration minerals identified allow defining the mineralogical facies and temperatures in each of the wells, and these are summarised in Table 5-3.

Table 5-3 Mineralogical facies of San Vicente geothermal wells (LAGEO, 2020)

Facies	Minerology	SV-1A Depth (m)	SV-2A Depth (m)	SV-2B Depth (m)	SV-3 Depth (m)	SV-5A Depth (m)	SV-5B Depth (m)	SV-5C Depth (m)	MINERALOGICAL TEMPERATURE
		MD	MD	MD	MD	MD	MD	MD	(°C)
ARGILLIC	esm, <cor, <qz, cryst, op, trid, <<ca, hem, <alun	0-430	0-390	0-416	0-380	0-430	0-420	0-420	50-120
ARGILLIC-PHYILLITIC	esm, <cor, <cl, qz, > > cryst, trid, < <ca, hem, <py, ceo, <nat	430-940	390-740	416-750	380-860	430-890	420-900	420-910	120-180
PHYLLITIC	<esm, <cor, >>cl, <il, il-mtm, >>qz, <pen, ca, wai, <<anh, laum <<ep, <py, <hem, <nat	940-1440	740-1233	750-960?		890-1240	900-1286	910-1350	180-210
PHYLLITIC-PROPYLITIC	il, cl, pen, <<cor, >>qz, ca, anh, wai, laum, hem, ep, py, <preh, anh, <clz, ser, <epi, <nat	1440-1830	1233-1331			1240-1798 based on 2 cores taken	1286-1450	1350-1750	210-260
PROPYLITIC	il, <cl, pen, >>qz, ca, >ep, anh, wai, <<preh, py, clz, esf, ser, <<gra, <<act, <<nat, << laum	1830-2539						1750-2250	>260

Nomenclature: esm - Smectite; cor - Corrensite; qz - Quartz; cryst - Crystobalite; op - Opal; trid - Tridymite; ca - Calcite; hem - Hematite; alun - Alunite; cl - Chlorite; py - Pyrite; ceo - Zeolite; il - Illite; mtm - Montmorillonite; pen - Pennine; wai - Wairakite; anh - Anhydrite; laum - Laumontite; ep - Epidote; preh - Prehnite; ser - Sericite; epi - incipient Epidote; esf - Sphene; gra - Granate; act - Actinolite; nat - Natrolite.

A brief description of the main mineralogical alterations assemblages are presented as follow:

- Calcite is present in all wells, and the project developer needs to estimate the calcite content in the geothermal wells to prevent the scaling risk during the testing period and operation life
- Pyrite is mainly presented in well SV-2A
- Quartz is found in wells SV-2A, SV-2B, SV-5A and SV-5C
- Epidote typically becomes abundant at a temperature above about 250°C, and the presence of epidote often coincides with the top of the economic geothermal reservoir (DiPippo, 2016b). In San Vicente geothermal wells, epidote is present in SV-1A, SV-2A, SV-5A, SV-5B and SV-5C
- Wairakite is another high-temperature indicator (>300°C) and is rarely present in wells SV-1A, SV-5C and SV-2A

- In well SV-5C occasional presence of granite, actinolite, epidote, and wairakite indicate that formation rocks have been exposed to temperatures close to 300°C (LAGEO, 2020)

During the drilling work of well SV-5A, partial and total circulation losses were reported and analysed. The circulation loss zones are associated with formation changes and fractures in the geothermal reservoir. Additionally, aquifers and their temperatures were identified based on well logs. Therefore, the permeability within the geothermal reservoir is mainly associated with fractures and fault zones, with an increase in high alteration mineralogy with an abundance of pyrite and calcite at the production zone of the well (Pichardo, 2013b).

5.1.5 Geochemistry

The geochemistry data has an essential role in the exploration phase and provides information to the geothermal project developers. The geochemistry data helps to define and update the drilling plans, design wells, select the size and type of power plant, and design the separation station and gathering systems. Additionally, during the operation phase, geochemistry data provides real-time information on the evolution of the reservoir, and it is one of the basic tools to sustainably manage the wells and the geothermal reservoir's response to production. The chemistry of geothermal fluids is established by the interaction of water and rock in the reservoir (DiPippo, 2016a).

The San Vicente hot springs, domestic water wells, and fumaroles covered in the updated geochemistry study carried out in 2005 are presented in Figure 5-3. The chemical results indicated that most of the waters are bicarbonate, and some tend to be sulfated. The deep water and discharges samples from well SV-1 are chlorinated and have sulfate and bicarbonate content, indicating evidence of meteoric water.

Using the deviation in the stable isotopic composition on thermal and non-thermal water, most of the hot springs and the domestic water wells are close to the meteoric line, see Figure 5-4. The discharge samples of well SV-1 (samples W1, W11, and LAV) are shifted in Oxygen-18 of ~4‰, suggesting the presence of high-temperature reservoir. Additionally, this shift indicates that the rock water interaction in San Vicente geothermal field is similar to Ahuachapán and Berlín geothermal field (LAGEO, 2020).

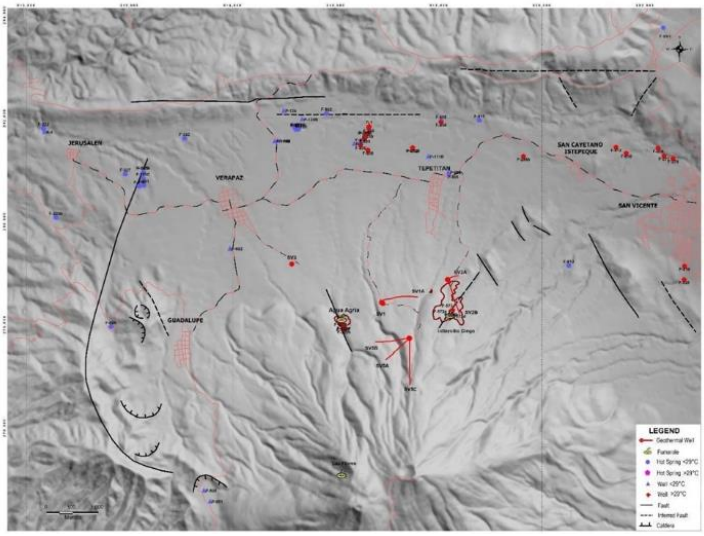


Figure 5-3 Location of hot springs, water domestic wells and fumaroles (LAGEO, 2020)

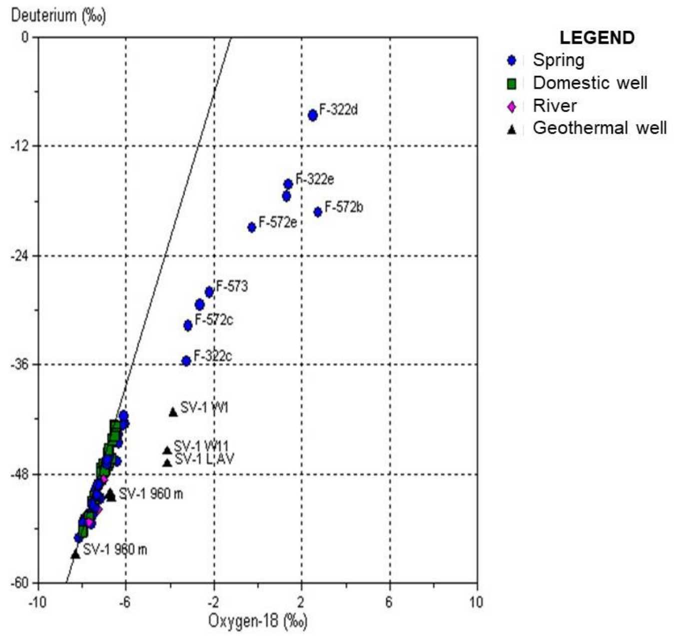


Figure 5-4 Oxygen-18 / Deuterium diagram for springs, domestic water and geothermal wells (LAGEO, 2020)

The water chemistry of the geothermal wells that have been discharged in the San Vicente project are presented in Table 5-4 Hydrochemical compositions of San Vicente geothermal wellsTable 5-4. The project owner has carried out a chemical analysis using these data.

Table 5-4 Hydrochemical compositions of San Vicente geothermal wells (LAGEO, 2020)

		Well / Sample				
		SV-1 Weirbox	**SV-1A Weirbox**	**SV-5A Wellhead**	**SV-5B Weirbox**	**SV-5C Weirbox**
Constituents	**Unit**	**Value**				
Ph		7.60	6.70	6.80	7.90	7.70
Na		3420.00	2494.00	3433.00	3029.00	3188.00
K		714.00	172.00	605.00	526.00	467.00
Ca		319.00	339.00	182.00	158.00	152.00
Mg		0.23	2.41	0.01	0.37	9.48
Cl	ppm	6958.00	4831.00	6370.00	5208.00	5574.00
SO4		41.00	52.00	20.00	85.00	104.00
HCO3		10.60	29.30	20.40	88.70	40.60
SiO2		646.00	573.00	588.00	686.00	519.00
B		107.00	65.00	90.00	61.00	86.00
Li		8.50	5.30	9.20	9.10	7.60
CE	µS/cm	20040.00	15920.00	17840.00	15540.00	16325.00
Ox-18	‰	-2.70	-2.40	-3.80	-3.60	-2.20
Deuterium		-38.10	-35.30	-45.70	-38.80	-37.00

The Na-K-MG triangular diagram is used to classify geothermal fluids into full or partially equilibrated and immature water. This diagram is used to predict the equilibrium temperature and the suitability of thermal water for the application of ionic solute geothermometers (Strelbitskaya, 2005). The equilibrium of geofluids of the San Vicente project is shown in Figure 5-5. First, waters from wells SV-1A and SV-2A are located in the partial equilibrated zone identifying a mixture of meteoric and geothermal water. Second, water from wells SV-1 and SV-5B are close to the chemical equilibrium at high temperatures. Finally, waters from well SV-5A are in equilibrium at high temperatures and evaporation, indicating an excess of enthalpy in the well (LAGEO, 2020).

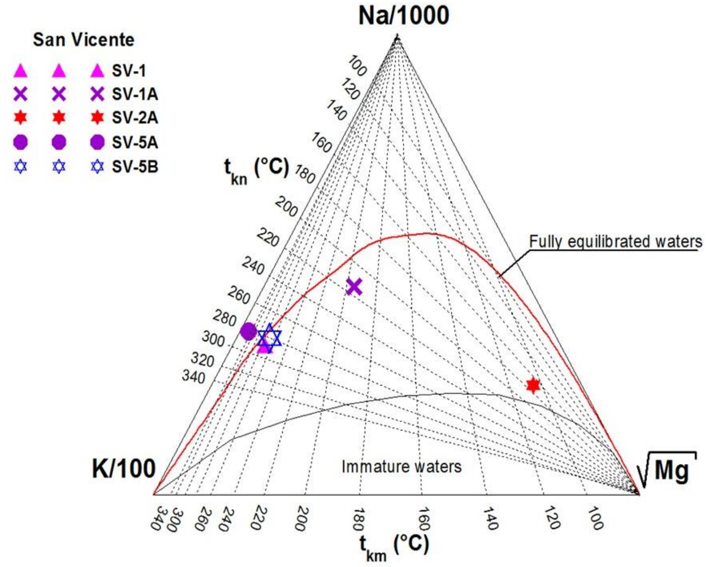


Figure 5-5 Na-K-MG triangular diagram of geothermal wells (LAGEO, 2020)

Well SV-5A has been discharged during long-term periods. The well operated in stable condition under the excess enthalpy regimen. During these periods, it has been observed that chemical species have reached a stable level during the discharges carried out in 2017 and 2019.

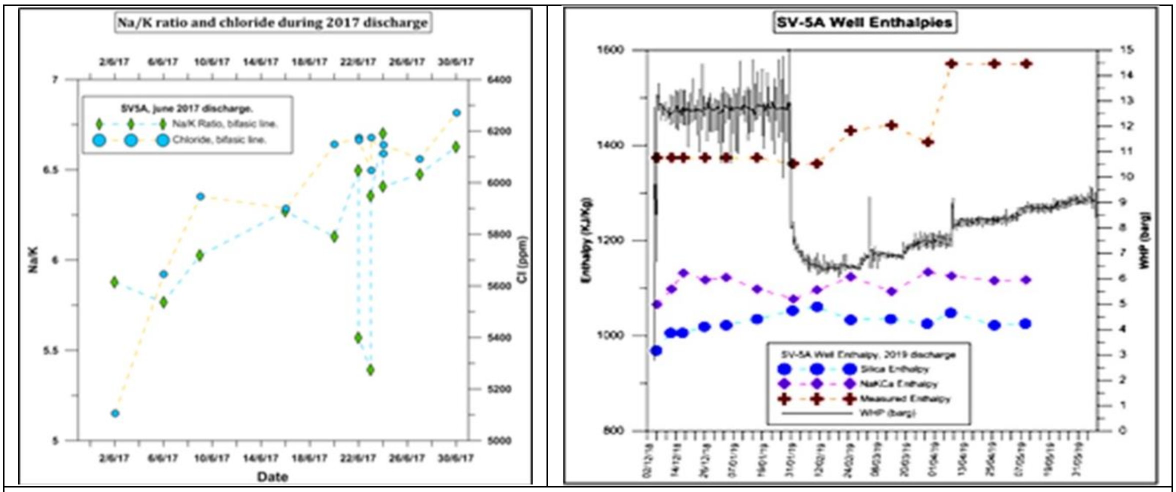


Figure 5-6 Chemical species and enthalpy of well SV-5A water (LAGEO, 2020)

The project owner has carried out a gas equilibrium evaluation; the results are presented in Table 5-5. A trilinear diagram of He, Ar, and N_2 is used to identify the source of geothermal gases, and the estimated temperatures are shown in Figure 5-7.

Table 5-5 Gases and non-condensable gases results (LAGEO, 2020)

Well	SV-1	SV-1A	SV-5A	SV-5B	SV-5C
Gas	Mmol gas/100 mol steam				
He	0.012	0.009	0.003	0.007	0.014
H_2	0.570	37.030	1.073	2.269	0.259
N_2	27.43	2.09	6.48	84.47	16.60
Ar	0.570	6.450	0.021	1.725	0.083
CH_4	0.010	1.790	0.345	0.723	0.694
O_2	1.410	2.030	0.018	0.052	0.005
H_2S	6.380	50.000	17.100	8.100	5.400
CO_2	125.50	218.30	321.40	254.10	479.10
% NCG	0.370	0.660	0.830	0.770	1.210

The result indicates that wells SV-1, SV-1A and SV-5B are not in the equilibrium zone, and the estimated temperatures are lower than those measured in the field. The gases from well SV-5A are in equilibrium at high temperature, have a magnetic component, and the geothermometer is related to the Infiernillo Ciego fumarole. Other important data based on the chemistry are the level of non-condensable gas content (NCG), emissions gases, scaling, and corrosion issues that can be evaluated to the project design. For San Vicente geothermal project, the highest value of NCG reported is 0.83%.

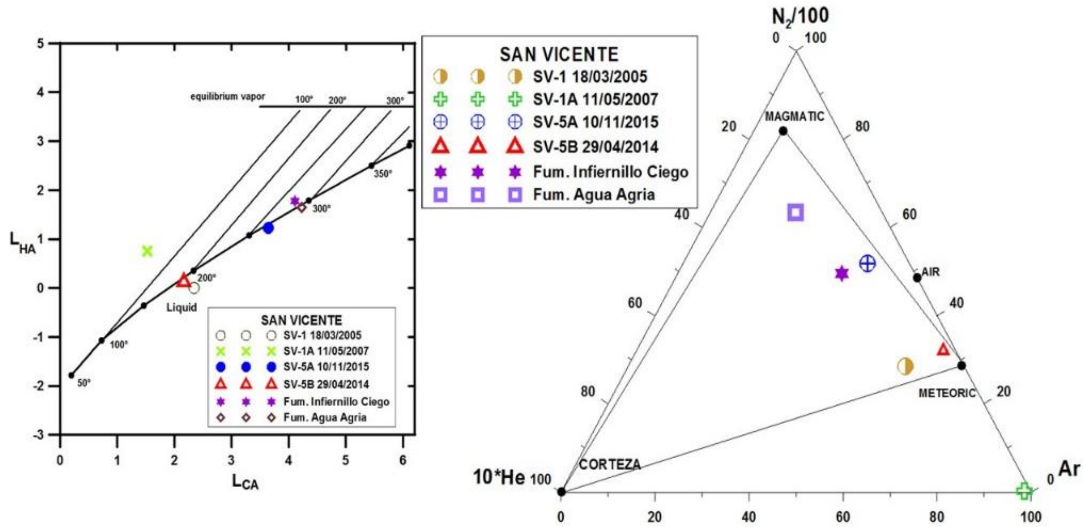


Figure 5-7 Estimated temperatures and gas sources of San Vicente geothermal wells (LAGEO, 2020)

The potential of scaling issues is important to be identified to design the project. The scaling process occurs when geothermal fluids become oversaturated with a given mineral. Steam only produces scale from liquid carryover or corrosion. Scaling from the brine can occur due to increased concentration from boiling or pH changes and/or brine cooling (DiPippo, 2016a).

For San Vicente geothermal projects, wells SV-1, SV-5A and SV-5B have significant calcite scaling potential. In addition, SV-1 and SV-5B have a moderated scaling potential for anhydrite. Figure 5-8 shows the calcite, anhydrite, and silica amorphous saturation index for these wells. The critical factor of amorphous silica precipitation is silica concentration, temperature, and pH (DiPippo, 2016a). The San Vicente geothermal wells have an amorphous silica scaling potential below 140°C.

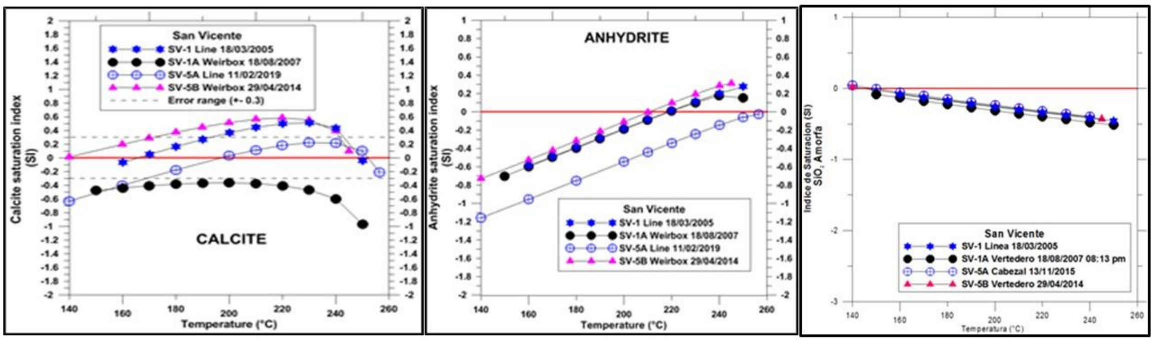


Figure 5-8 Calcite, anhydrite and amorphous silica saturation index (LAGEO, 2020)

Using Pourbaix diagrams, the corrosion behaviour of metals can be interpreted in geothermal fluids (Papic, 1991). The Pourbaix diagram for San Vicente geofluids based on well SV-5A is shown in Figure 5-9 and indicates that separated brine is located in a zone where the corrosion might be considered low. At the same time, the condensed steam is located in a zone of medium to high potential corrosion phenomena due to its closeness to Fe^{+2a}. Therefore it is necessary to specify and select materials that can deal with the corrosion phenomena during the project operation that must be considered during the design phase.

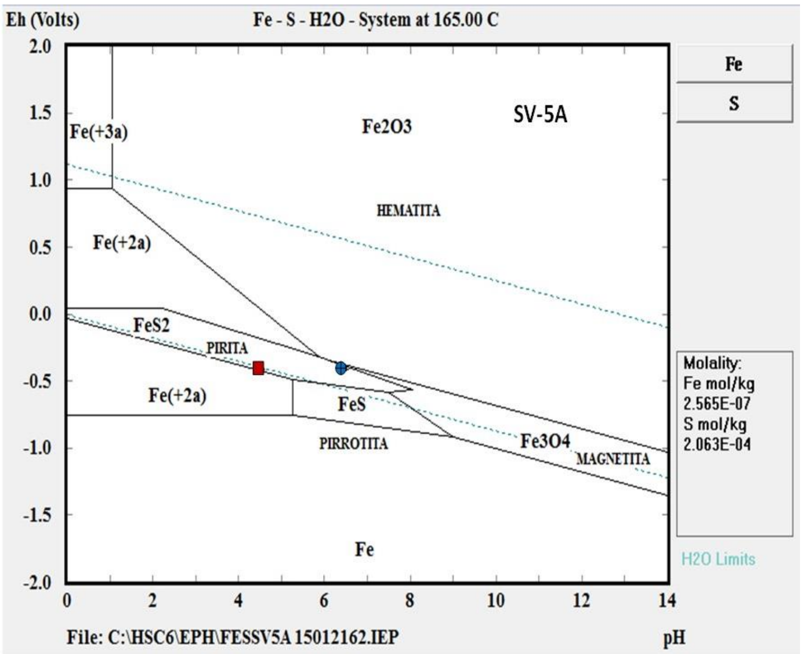


Figure 5-9 Pourbaix diagram of geofluids from well SV-5

The overall evaluation of the geochemical data for the San Vivente project suggests that the best approach to set the design parameter for the project should be based on the geochemical characteristic of the well SV-5A due to it having reached the chemical equilibrium.

5.1.6 Geophysics

Most geothermal developers have used geophysical applications to geothermal resources exploration using combined magnetotelluric (MT) and time-domain electromagnetic (TDEM) resistivity surveys. The geothermal project developers base the geothermal resource decisions on risk assessment. The resource conceptual models mainly support the risk assessment. Additionally, well test data and numerical reservoir simulation are used when they are available. A geothermal best practice for high decisions has recently focused on using a conceptual model approach for well targeting and resource capacity assessment (DiPippo, 2016a). The project developer, by 2015, has carried out 105 magnetotelluric surveys to develop a three dimensional (3D) electrical resistivity model of the geothermal concession area, see Figure 5-10.

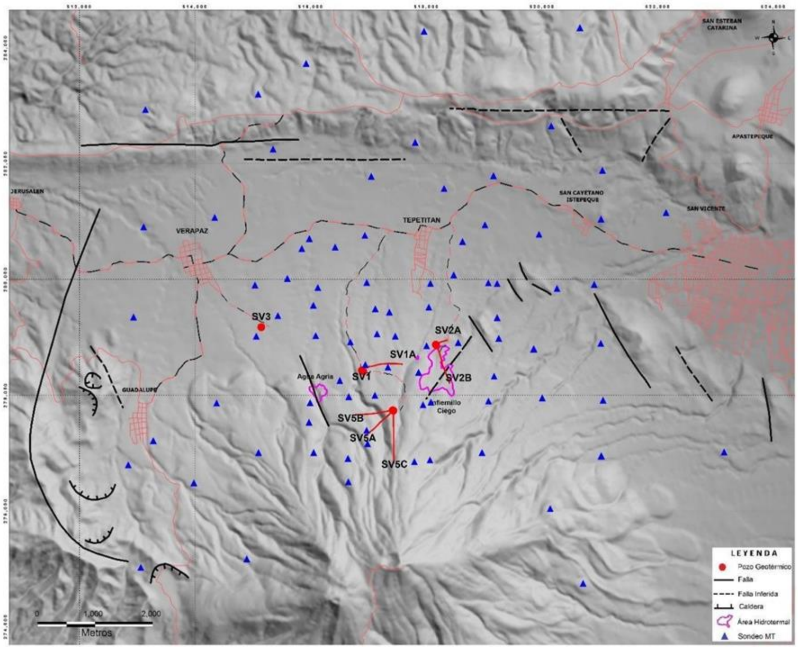


Figure 5-10 Distribution of MT/TDM surveys in San Vicente project (LAGEO, 2020)

The drilled wells in the San Vicente geothermal project and the resistivity isocontour at +500 m a.s.l. are shown in Figure 5-11. This model suggests a hydrothermal anomaly extending to the south with resistivity contour values below 15 Ohm-m, where most geothermal wells are located and can be interpreted as the first geothermal reservoir zone.

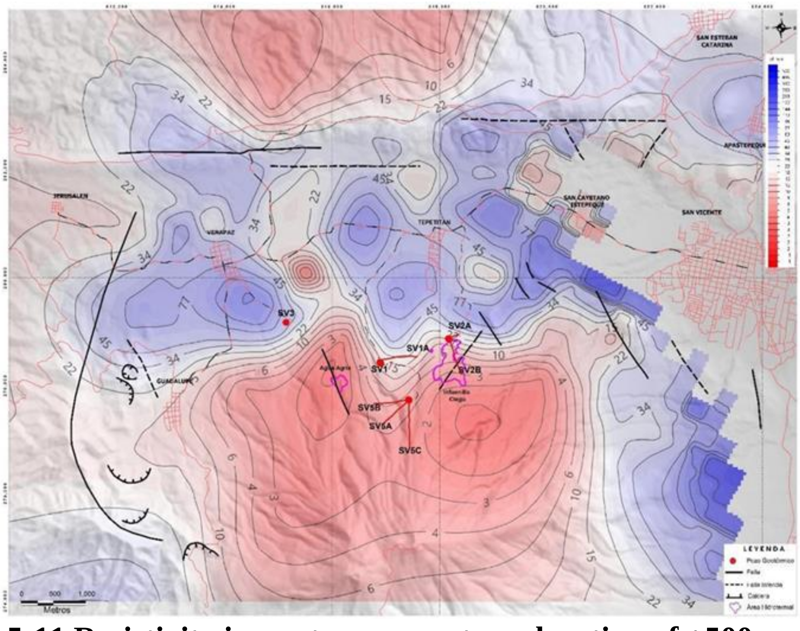


Figure 5-11 Resistivity isocontour map at an elevation of +500 m a.s.l. (LAGEO, 2020)

Figure 5-12 is shown the resistivity range from 0 to -500 m a.s.l associated with the feed zones of the reservoir in the range from 7 to 21 Ohm-m. Additionally, the coloured dots shown in the figure represents the feed zones identified during the drilling works. Finally, the isocontour of 45 Ohm-m is considered the resistivity cap at -1000 m a.s.l.

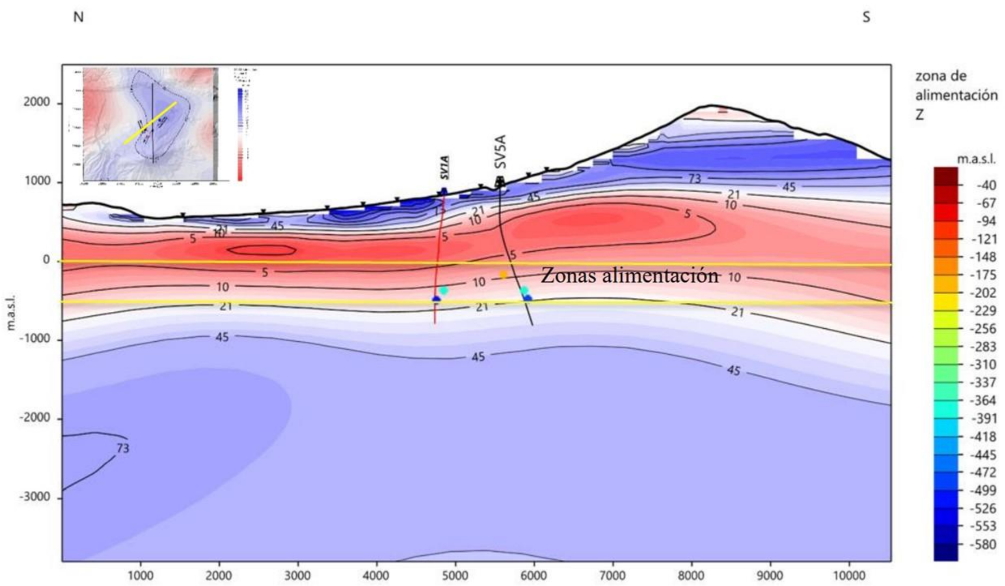


Figure 5-12 Resistivity profile – N - S. Feed zones in the range from 0 to -500 m a.s.l (LAGEO, 2020)

It is possible to identify a superficial cap with a low resistivity of 5 Ohm-m and define it as the reservoir seal cap rock based on geophysics profiles. The medium resistivity layer defines a conductive cap from 5 to 45 Ohm-m where the reservoir is located. Nevertheless, it is important to emphasise that the resistivity range from 7 to 21 Ohm-m is approximately the range where drilled wells have shown production and high-temperature values. The observed resistivity sequence is typical for a geothermal reservoir in a volcanic structure. This resistive – conductive – resistive environment has been determined by the geophysics result of the San Vicente geothermal project and suggests, on average, a reservoir with resistivity from 5 to 45 Ohm-m between 0 to 1000 m a.s.l. (LAGEO, 2020).

5.1.7 Geophysics conceptual model

The surveys carried out with the geophysics methods have allowed the project owner to build up the geophysical conceptual model of the San Vicente geothermal reservoir based on the structural alignments and anomalies suggested by gravimetric, Head On, seismic and resistivity surveys. The results of these surveys are summarised in Figure 5-13. The up-flow zone has been identified at the southern part of the reservoir. The fluid circulation pattern to the discharge zone of the reservoir starts from the up-flow zone to the north part of the reservoir.

The up-flow zone can be associated with the magma chamber of Chinchontepec volcano and is estimated at twelve kilometres deep, and the geothermal fluid circulation is defined as going through the existent faults in the reservoir with predominant direction to the north, as is shown in the geophysics conceptual model.

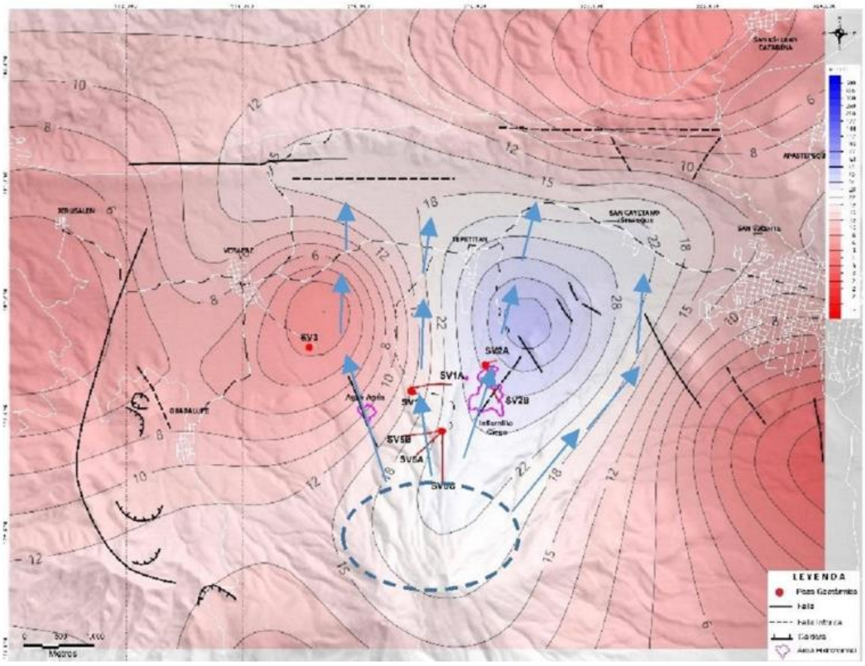


Figure 5-13 Geophysics conceptual model with the up-flow zone and the fluid circulation pattern (LAGEO, 2020)

A conceptual model cross-section, N-S orientation, is presented in Figure 5-14. This cross-section model shows the main elements of the San Vicente geothermal system, and they are described as follows:

- Resistivity values characterise the reservoir range from 5 to 45 Ohm-m
- Reservoir thickness varies between 500 and 800 m
- The heat source of the system is located under the volcanic complex of San Vicente
- The fluid up-flow zone is located south under the Chinchontepec volcano, where the conductive zone shows values less than 10 Ohm-m
- The explored zone represents the major hydrothermal alteration zone and becomes the production area of interest

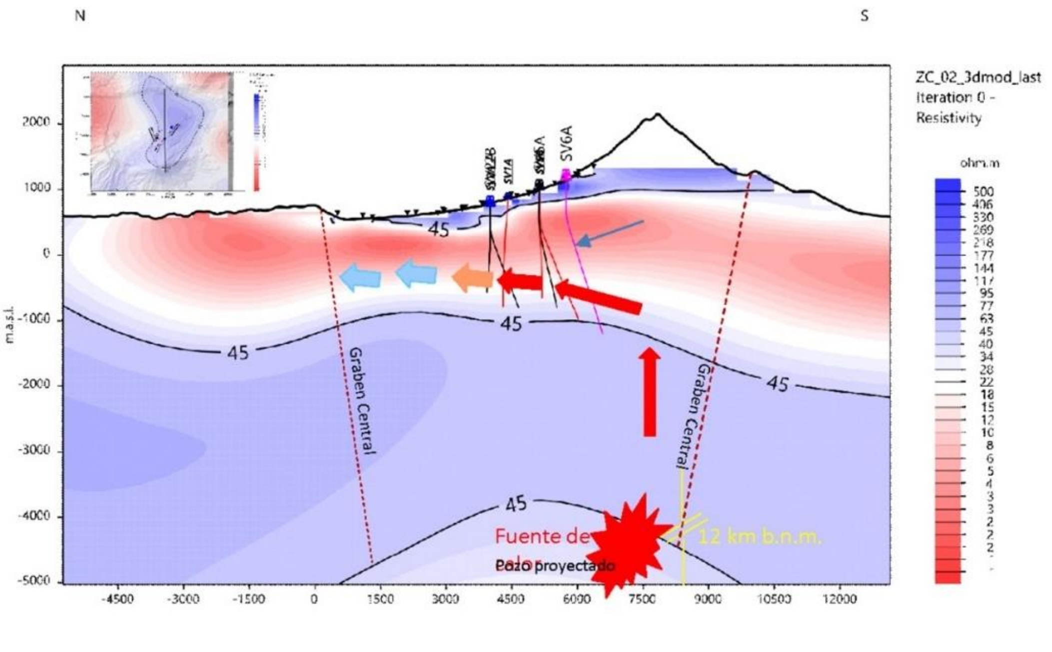


Figure 5-14 Geophysics conceptual model, N-S cross-section (LAGEO, 2020)

The most important feature is matching the geophysics and geological map in the NW-SE faults systems, with the fault associated with Agua Agria fumarole and the structural features to the northeast with the Infienillo Ciego fault.

5.1.8 San Vicente geothermal conceptual model

The project owner, LAGEO, developed a conceptual model in 2020 of the geothermal reservoir based on the result obtained from different geoscientific studies carried out in the geothermal area of the San Vicente project, which is described in this section. The conceptual model integrates and summarises the relevant aspects from geology, geochemistry and geophysics to understand the San Vicente geothermal system.

The main elements of this conceptual model are:

- *Heat source.* The heat source is associated with a magmatic chamber of the Chinchontepec volcano, with an estimated depth of less than 12 km
- *Recharge zones.* Two recharge zones have been determined, one in the upper part of the northern flank of the San Vicente Volcano and the second one corresponds to the upper part of the central graben at the north of the concession area
- *Circulation pattern.* The anomalies from gas, gravimetry, and MT surveys indicate that the main circulation pattern is north- northwest. In the northern part of the study area, fluids are derived to the east when they reach the central graben
- *Cap-rock.* From the geological observation, the cap-rock of the San Vicente geothermal reservoir corresponds to the unit of intercepted acid tuffs in some of the drilled wells, between the depths of 500 to 1,025 m. From the MT surveys, the cap-rock is defined as a conductive zone with resistivity values less than 5 Ohm-m, with a thickness ranging from 500 to 800 m, reflecting the hydrothermal alteration. From the analysis of the geochemical surveys, there is no connection between the reservoir waters and shallow aquifers, suggesting an efficient seal cap-rock. Finally, from the thermal point of view, the cap-rock is observed as an interval with a high conductive thermal gradient, with temperatures of 50°C and 200°C in the top and bottom, respectively
- *Reservoir.* The reservoir has been identified from MT surveys in the range of resistive values from 5 to 45 Ohm-m. The reservoir thickness is estimated between 500 and 800 m. From the well logs, the San Vicente project reservoir is liquid dominant with temperatures ranging from 250 to 265°C, and enthalpies are higher than the corresponding liquid phase
- *Up-flow zone*. The up-flow zone is located south below the north flank of the Chinchontepec volcano structure
- *Discharge zone*. The superficial geochemistry water studies suggest that the most likely discharge area from the San Vicente geothermal system is the Obrajuelo hydrothermal manifestation area

The following conceptual scheme of the San Vicente geothermal system is based on the elements and studies described above, as shown in Figure 5-15, Figure 5-16 and Figure 5-17.

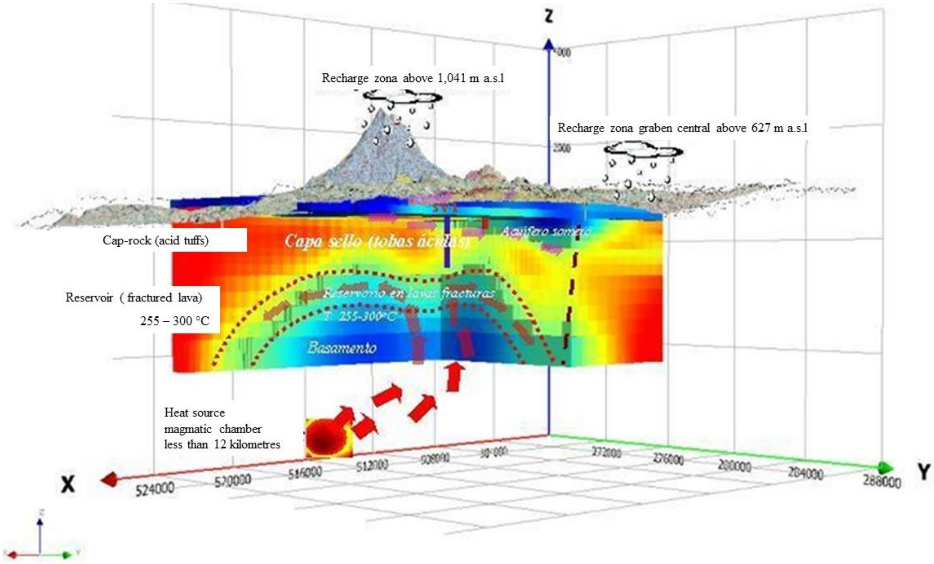


Figure 5-15 Conceptual model of San Vicente geothermal system

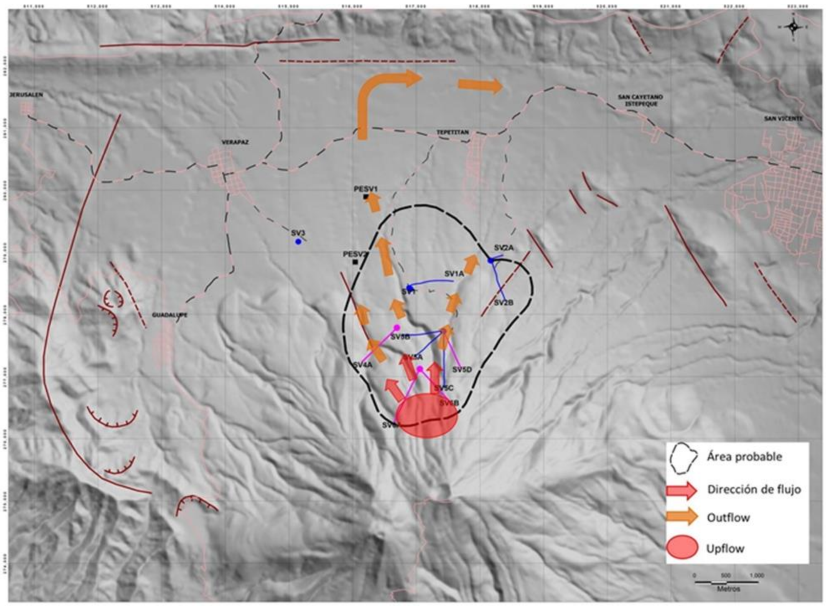


Figure 5-16 Conceptual model: Up-flow zone and circulation pattern areas

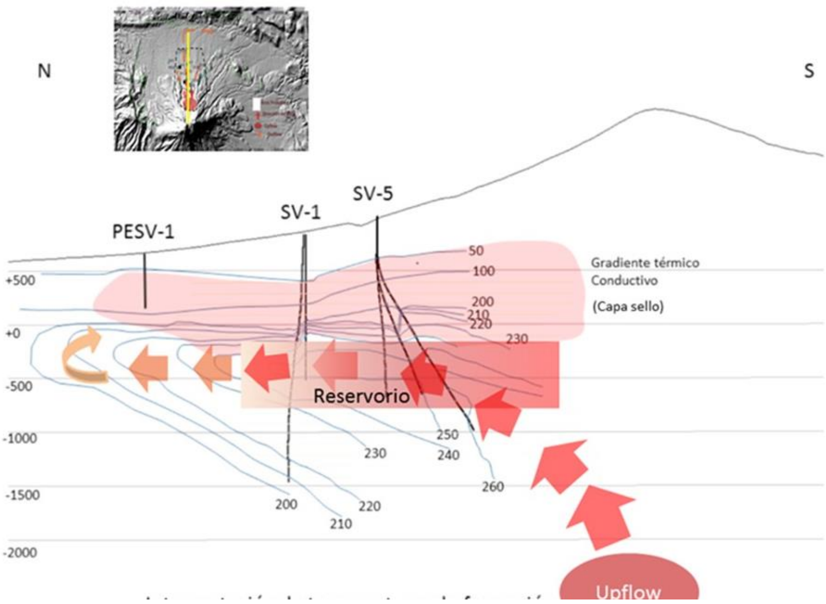


Figure 5-17 North-South circulation pattern view and formation temperatures

A common best practice to evaluate the conclusion of surveys and analyses conducted to support high-value geothermal resource decisions is to contract a consultant geothermal expert or company (DiPippo, 2016a). The experts should check if the data and analyses are consistent with the conceptual models and determine, at the same time, the uncertainty in the data and its interpretation to mitigate the geothermal risk.

5.2 San Vicente resource estimation

Geothermal resource estimation can be defined as the amount of geothermal energy that might become available for utilisation purposes. The two most common simple methods for resource estimation are the stored heat method and the power density (DiPippo, 2016a).

5.2.1 Geothermal resource estimation – stored heat or volumetric method

Geothermal resource assessment evaluates well surface discharges and borehole data and integrates it with the geoscientific results obtained from geological, geophysical, and geochemical surveys. The main focus of the geothermal resource assessment is to confirm the existence of a reservoir that could be utilised at a specific capacity for a certain period to ensure sustainable production over a long term period.

The geothermal assessment can be made during the exploratory stage dealing with the characteristics of the thermal surface manifestations, geophysical results, the geological setting, and the temperatures inferred from geothermometres. The result of this first assessment is used to present a conceptual model of the potential geothermal reservoir and serve as the basis to set the drilling targets to confirm the existence of a geothermal resource. The geothermal assessment and the conceptual model are updated by incorporating the drilling data and well logs, in addition to testing.

The volumetric method, patented by the USGS (United States Geological Survey), uses the Monte Carlo simulation technique and calculates thermal energy in the rock and the fluid, which might be utilised based on specific reservoir volume, reservoir temperature, and reference temperature (Sarmiento & Steingrímsson, 2011).

The volumetric method assumes that the reservoir rocks are porous and permeable, and that the mass extracted from the reservoir carries the utilised heat from the volume of the reservoir. Additionally, no geothermal fluid recharge or thermal energy flux to the reservoir volume is assumed. Equation (5.1 is used to calculate the power potential of a homogeneous reservoir by estimating the amount of energy that can be extracted and converted into electricity.

$$E_t = E_r + E_w = (1 - \varphi)\rho_r C_r V(T_r - T_0) + \varphi\rho_w C_w V(T_r - T_0) \tag{5.1}$$

In this equation, T_r is the average reservoir temperature (°C), and T_0 is the reference temperature (°C) that is determined by the thermodynamic process. $V = AH$, is the reservoir volume, in m^3, A is the surface area, in m^2, and H is the thickness of the reservoir, in m. E is the heat energy (J), φ is the porosity of the rock (%), C is the specific heat (J/°C*kg), and ρ is the density (kg/m^3). Additionally, the subscripts r and w refer to rock and water, respectively.

E_t usually refers to the accessible resource base, and it can be converted to recoverable power in MW by Equation (5.2.

$$P = \frac{E_t R_f \eta}{Lt} \tag{5.2}$$

P	=	Power plant capacity (MW)
R_f	=	Recovery factor (%)
η	=	Conversion efficiency (%)
L	=	Power plant capacity factor (%)
t	=	Power plant lifetime (years)

Moreover, *t* is the power plant planned lifetime and represents the total time assumed for the power units in operation and gives an average output capacity in MW (*P).* The conversion efficiency (η) is the percentage of heat converted into electricity, R_f is the recovery factor used to determine the amount of heat extracted from the reservoir rock, and L is the power plant capacity factor that combines the plant availability and capacity (Rutagarama, 2012).

This study runs a Monte Carlo approach to estimate the reservoir capacity. The purpose was to estimate the capacity of the reservoir to produce electricity, assuming 30 years for the power plant lifetime. Since some of the reservoir parameters are uncertain, the Monte Carlo simulation established a probability distribution for each of them. The common distribution functions of poorly known parameters are the rectangular, triangular, constant, and normal distribution. The normal and triangular distributions are suitable when actual data is limited, and it is known that they fall near the centre of the limits. The rectangular distribution applies reasonably in the model in the absence of any other parameters (Rutagarama, 2012). Table 5-6 shows the data used by the project owner in the volumetric stored heat estimation.

Table 5-6 Volumetric method – input data.

Item	Parameter	Symbol	Units	Distribution	Min	Best value	Max
1	Surface area	A	Km2	Triangular	4	7	11
2	Thickness	H	m	Triangular	800	1200	1500
3	Reservoir temperature	T_r	°C	Triangular	230	250	270
4	Porosity	ϕ	%	Triangular	5	10	15
5	Rock heat capacity	C_r	J/°Ckg	Fixed value	N/A	850	N/A
6	Rock density	ρ_r	kg/m3	Fixed value	N/A	2600	N/A
7	Recovery factor	R_f	%	Fixed value	N/A	10	N/A
8	Reference temperature	T_0	°C	Fixed value	N/A	100	N/A
9	Conversion efficiency	η	%	Constant	N/A	11	N/A
10	Power plant capacity factor	L	%	Constant	N/A	95	N/A

The size of the surface areas covered in the method to estimate the reservoir energy capacity includes the geophysical anomalies of interest from the MT surveys. In addition to these, areas with superficial manifestations and the area considered as the zone of system discharge are included. Figure 5-18 Areas used to estimate the reservoir capacityFigure 5-18 shows the superficial areas of interest for the reservoir capacity assessment (LAGEO, 2020).

The thickness parameter was estimated from the temperature log profiles. The reservoir thickness has been estimated between 800 to 1500 m, with the most likely value of 1200 m (LAGEO, 2020). The porosity parameters used are the most common values used in stored heat estimation capacity, specifically in uncertainty cases (Hersir et al., 2020). The thermal recovery factor determines how much energy can be extracted from the reservoir over a given period, and it is the most difficult parameter to estimate. Historically, a constant recovery factor of 0.25 has been used for uniformly porous and permeable geothermal reservoirs. A more recent analysis of data from fractured reservoirs indicates that the recovery factor is closer to 10% (Hersir et al., 2020; Rutagarama, 2012).

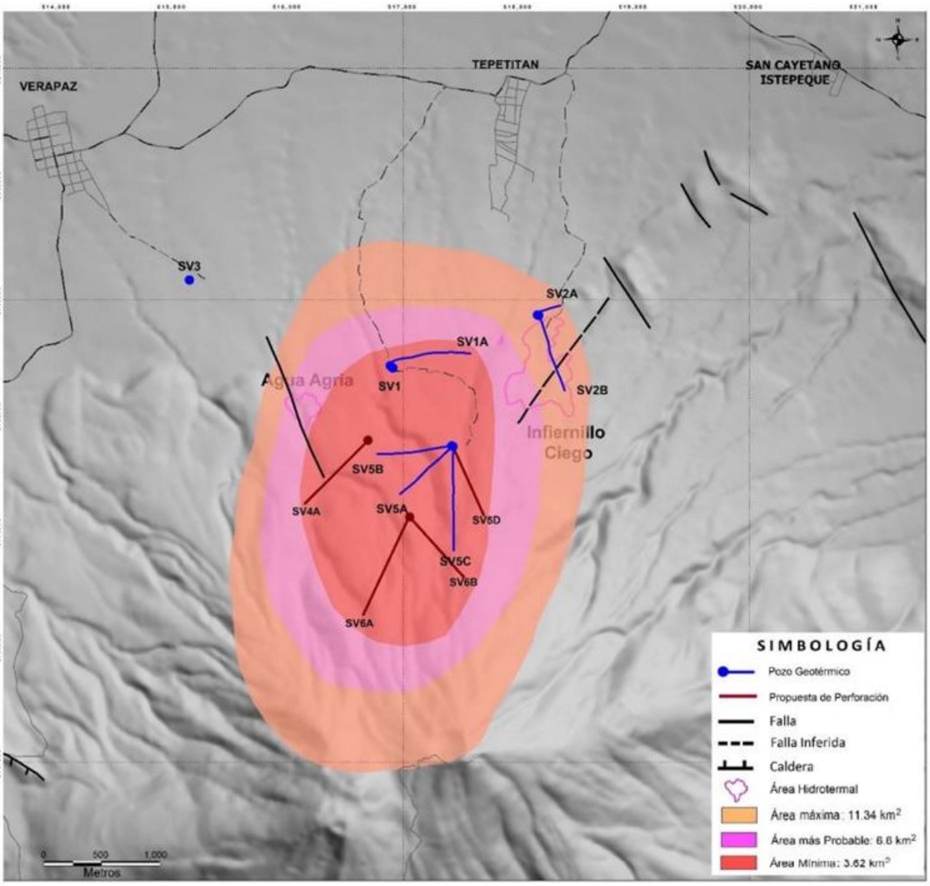


Figure 5-18 Areas used to estimate the reservoir capacity

For this study, the reference temperature is 100 °C assuming that the scaling issue due to silica and calcite is treated during the production lifetime. However, others choose a reference temperature of the ambient temperature or use temperature values between 30 – 40 °C for applications of space heating, the temperature of 180 °C for conventional power plants, and 130 °C for binary plants applications (Sarmiento & Steingrímsson, 2007).

The results of the volumetric assessment are summarised in Table 5-7 and presented in Figure 5-19. This result shows that the volumetric method predicts with 90% confidence that power production capacity lies between 24 – 53 MW for 30 years.

Table 5-7 Probabilistic result of the volumetric assessment

Lifetime (years)	*30*
Probability Value	**Output estimation**
P90	27 MW
Most likely	38 MW
P50	37 MW
90% confedence interval	24 - 53 MW

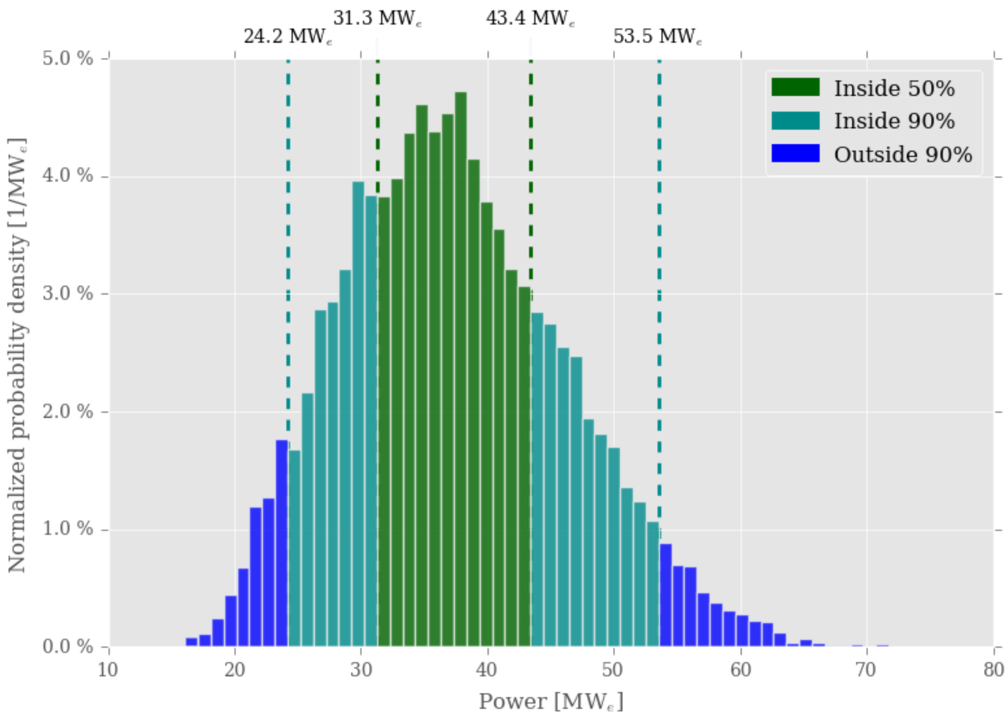


Figure 5-19 Results of volumetric assessment – Probability distribution of power capacity for a geothermal project with a lifetime of 30 years

From the estimated production capacity of the reservoir, assuming a lifetime of power production of 30 years and reference temperature of 100 °C, it can be concluded that the San Vicente geothermal project can sustain a production capacity close to 30 MW. Since the project has tested wells SV-5A and SV-5B with satisfactory results, the risk is minimised if the project is developed strategically in phases. The following section will propose one development plan.

Landsvirkjun has the policy that prior to a decision to build a geothermal power plant, at least 50 – 70% of the steam should be available, and the production wells should have been flowed tested for several months (Palsson, 2021). Another approach, according to Zarrouk and McLean (2019), is when the project owner is looking for funding from a commercial or multilateral lender, evidence that 62% of the potential power development through well testing is the best technical support to support the project. This experience is considered in the assumptions of the development of the San Vicente project in this report.

5.3 Geothermal field development plan

The feasibility study presents a plan to develop the geothermal field based on the wells design and engineering, environmental and social aspects, and the capital and operating cost estimates. These development plans show the locations of production and reinjections wells for the estimated power capacity according to the conceptual models of the geothermal reservoir, the volumetric assessment of the geothermal production capacity, and the results of the production wells drilled to date. Additionally, these plans represent the location of the power plant and the pipelines to connect the wells to the plant (ESMAP, 2021; Gehringer & Loksha, 2012). A key component of a feasibility study is an explicit statement of the proven generation capacity of the wells drilled to date (ESMAP, 2021).

5.3.1 Characteristics of the drilled wells

In San Vicente geothermal field, ten geothermal wells of commercial diameter and depth have been drilled from 1978 to 2015. Figure 5-20 shows the location of these wells in the geothermal area, and Table 5-8 summarises the main characteristics of each well.

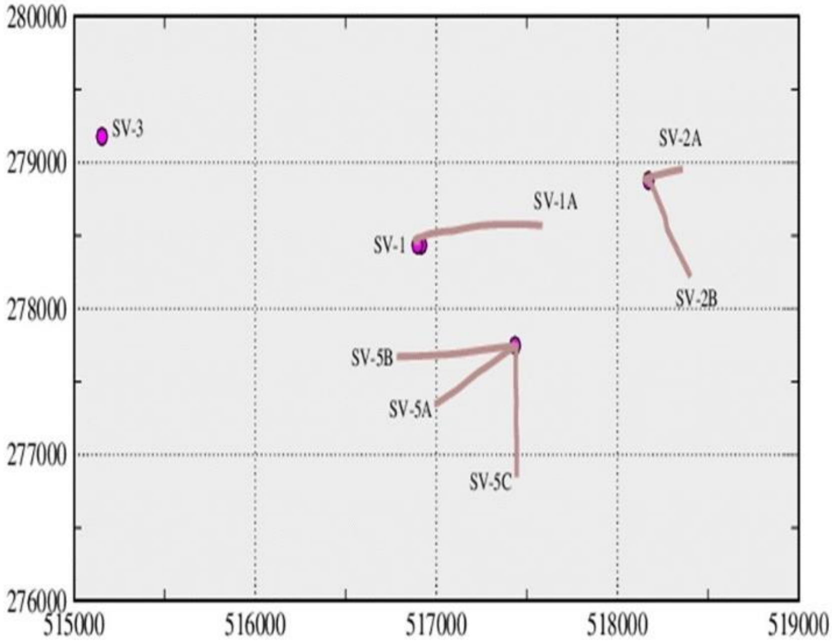


Figure 5-20 Location of San Vicente geothermal wells

Table 5-8 Main technical characteristics of San Vicente geothermal wells (LAGEO, 2020)

		Well / Type							
Item	**Units**	**SV-1 Vertical**	**SV-1A Directional**	**SV-2A Directional**	**SV-2B Directional**	**SV-3 Vertical**	**SV-5A Directional**	**SV-5B Directional**	**SV-5C Directional**
Start drilled date		26/05/1979	31/05/2006	12/01/2007	16/04/2015	03/04/2007	13/10/2012	30/07/2013	03/02/2015
Finish drilled date		07/11/1979	14/12/2006	17/03/2007	10/06/2015	10/05/2007	18/01/2013	14/11/2013	03/04/2015
Perforation time	days	165.00	197.00	64.00	55.00	37.00	97.00	107.00	59.00
Depth	m	1346 TVD*	2539 MD**	1331 MD	1550 MD	860 TVD	1785 MD	1843 MD	2250 MD
Liner diameter	in	7 5/8	7	7 5/8	9 5/8	13 3/8	9 5/8	9 5/8	9 5/8
Atmospheric presure	bar	0.917	0.917	0.929	0.929	0.933	0.901	0.901	0.901
Inyectivity index	lt/bar-s	0.7	2.3	0.9	10	-	4.8	1.9	1.3
Depth of feed zones	m	900	1300	1000	1100	-	1500	1300	1500 - 1600
Water level	m	430	435	420	395	100	523	576	565
Maximum temperature	°C	243	252	153	210	82	256	238	265
Depth of maximum temperature	m	1275	1200 - 1300	1100 - 1200	525 - 1125	700	1400 - 1600	1250	1600
Wellhead presure	bar a	4.7	-	-	-	-	8.4	5.3	-
Brine flow	kg/s	8	-	-	-	-	25	25	-
Steam flow	kg/s	2.5	-	-	-	-	20	9.9	-
Enthalpy	kJ/kg	1142	-	-	-	-	1600	1300	-
Absorption capacity	lt/s	-	-	50	50	-	-	-	-

TVD* = Total vertical distance MD** = Measure distance

It is observed that the deepest well is SV-1A, with 2,539 m, and the shallowest is well SV-3. Well SV-3 was abandoned because of its low temperature of 82°C that was reported at 100 m deep during the drilling works (LAGEO, 2020). The maximum measured temperature is 265°C in well SV-5C. It should be noted that most of the wells are directional, and the drilled pads for the San Vicente project have been designed with the capacity to drill four wells from the same pad.

5.3.2 Drilling strategy

The San Vicente project has geothermal wells that produce a mixture of steam and liquid, and the current data from the wells tested indicate that the geothermal reservoir discharges geothermal fluids with high enthalpy levels that can be utilised for electricity generation. The production tests performed in wells SV-5A and SV-5B indicate that these wells are able to maintain stable discharge for the long term under the condition presented in Table 5-9.

Table 5-9 Production condition of wells SV-5A and SV-5B (LAGEO, 2020)

Well Name	Wellhead pressure	Total mass flow	Discharge Enthalpy	Steam Fraction	Power Capacity	Maximum Temperature	NCG Content
	barg	kg/s	kJ/kg	%	MW	°C	wt % of total flow
SV-5A	8.4	45	1600	44%	10	256	0.83
SV-5B	5.3	35	1300	28%	5	238	0.77

A simulation using the production test results has been done to estimate the power output of wells SV-5A and SV-5B at a range of separating pressures. The results are shown in Figure 5-21. These calculations assumed that it is possible to operate the condenser at a pressure of 0.1 bar and an isentropic turbine efficiency of 90%.

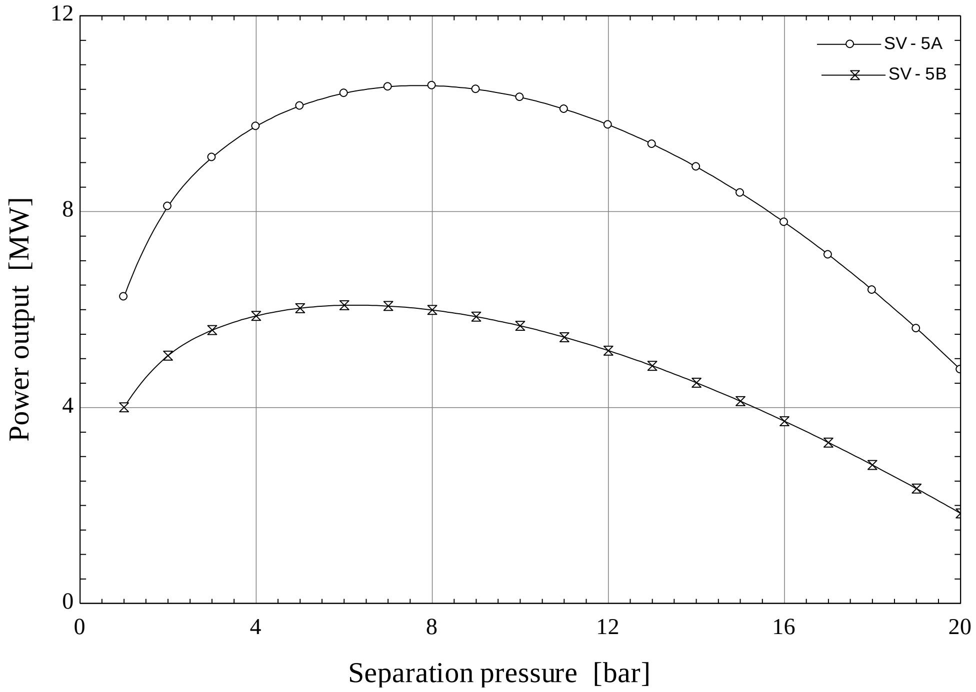


Figure 5-21 Power output for wells SV-5A and SV-5B at different separation pressure

The separator pressure values for each well, which allow the maximum power output from wells SV-5A and SV-5B, are 8 bar, with 10.6 MW, and 6 bar, with 5.4 MW.

The capacity of the well represents its gross electrical power capacity in MW. Geothermal wells are considered successful only where the capacity in most cases is above 3 MW or higher. A commonly used rule of thumb is that every successful production well will provide enough steam to produce 5 MW in the power plant. Depending on the project size and other circumstances, some capacities as low as 3 MW per well can be satisfactory. (Gehringer & Loksha, 2012; IFC, 2013).

A typical 30 MW power plant project needs 5 to 6 production wells and 2 to 3 reinjection wells (DiPippo, 2016b). If the project developer plans to develop a 50 MW power plant, 13 production wells and 7 reinjection wells may be needed (Gehringer & Loksha, 2012). Using these approaches, the wells required to develop a geothermal project are in the following ranges: production wells in the range of 65 to 71 %, and reinjection wells in the range of 29 to 35%, of the total numbers of wells required to produce the total estimated capacity. Using this approach for the San Vicente project, it will be assumed that the number of reinjection wells required to develop the project is half of the production wells. The drilling strategy in the development plan must assume a drilling success rate during the development phase of 70% and a reasonable number of unsuccessful wells, in addition to their estimated costs, should be included in the project (ESMAP, 2021; IFC, 2013).

Considering a specific steam consumption of the power plant at 2 kg/s/MW approaching the steam rate consumption of the turbine at the Berlin power plant (Horie, n.d.), the steam requirement for a 30 MW power plant would be 60 kg/s. The project has currently proven production at the wellhead valve, of 30 kg/s of steam available, which has added the testing results of wells SV-5A and SV-5B presented in Table 5-9. This report is going to model conversion technologies in the following chapter using the technical information available and the assumption of the drilling strategy. The assumptions of the drilling strategy to develop the San Vicente geothermal project are summarised in Table 5-10.

Table 5-10 Assumption to define the number of wells required for the project.

Description	Value	Unit
Total capacity	30	MW
Turbine steam rate consumption	2	kg/s/MW
Total steam flow required por the project	60	kg/s
Production wells drilled	2	
Steam available at the well head	30	kg/s
Additional steam required	30	kg/s
Average output per well	5	MW
Average well steam production	10	kg/s
Drilling success rate	70	%
Number of aditional production well	4	
Total of production well required	**6**	
Total of reinjection well required	**3**	

According to the project developer, the project has well pads ready to drill the required wells. These well pads are identified as SV-4 and SV-6. Additionally, the project has the option to drill an additional well on well pad SV-5 (LAGEO, 2020). Five additional wells will be required, four wells for production purposes and one for reinjection. The total number of wells to be drilled takes into account uncertainty with the drilling success rate of 70%. In summary, at least six production wells and three reinjection wells are required to operate the 30 MW power plant, making a total of nine wells.

The well pads' location and target orientations of the proposed production wells are shown in Figure 5-22. The proposed production well will be drilled in well pads SV-4, SV-5, and SV-6.

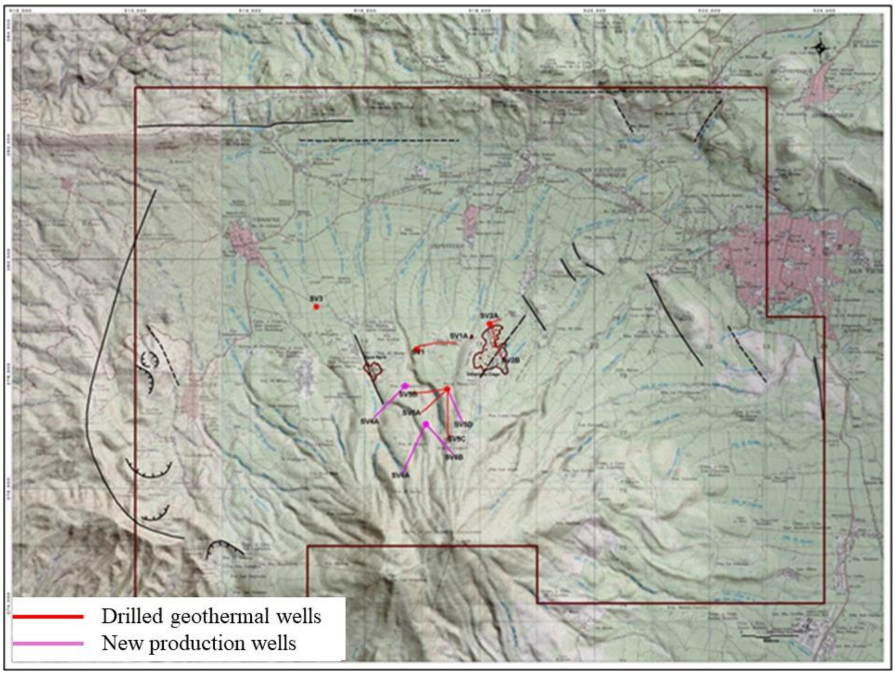


Figure 5-22 Orientation proposal and location of production wells to be drilled (LAGEO, 2020)

The drilling strategy needs to include a proper reinjection plan to guarantee the long term sustainability and even reach the stable operation of the geothermal reservoir response to production. The San Vicente geothermal project has a liquid-dominant reservoir ranging between 60 to 70 % of fluid available for rejection, and the risk of thermal or chemical changes could be an issue. Monitoring wells and tracer tests during operation will give an early warning of this possible problem and allow time to adjust to mitigate the negative effect in the reservoir (DiPippo, 2016b).

The San Vicente project has successfully drilled two reinjection wells, SV-2A and SV-2B, with good permeability and reinjection capacity of at least 50 kg/s each. The project will have a total capacity of 150 kg/s at the well pad SV-2 where the third reinjection well is proposed to be drilled in the same well pad. With this capacity, the project may easily manage the brine produced from the production wells and guarantee the sustainable utilisation of the power plant.

5.4 Harnessing development plan

The geoscience surveys, drilled well data, and wells surface discharge results were presented in previous sections of this Chapter. This information has confirmed a high-temperature geothermal reservoir with a permeability identified by the mineralogical alteration, fractures, and fault zones targeted during the drilling work at the San Vicente geothermal area. At the same time, all this information is the basis for preparing the conceptual model and the resource assessment of the geothermal reservoir. The resource conceptual models and estimation capacity are the support to help the project developer to evaluate the reservoir's risk.

The conceptual model and the resource assessment serve as the basis to set the drilling targets for the next phases of the project development. From the reservoir's resource assessment, which assumes a lifetime of power production of 30 years and reference temperature of 100 °C, it can be concluded that the San Vicente geothermal project can sustain a production capacity close to 30 MW.

This report is going to model conversion technologies using the technical information available and the assumption of the drilling strategy. The drilling strategy considers that every successful production well will provide enough steam to produce 5 MW in the power plant, and the number of production wells are in the range of 65 to 71 %, and the reinjection wells in the range of 29 to 35%, from the total numbers of wells required to produce the total estimated capacity.

The power plant design needs to specify and select materials to deal with corrosion during the project operation. The overall evaluation of the geochemical data for the San Vicente project suggests that the best approach to set the design parameter for the project should be based on the geochemical characteristic of the well SV-5A. Additionally, the design needs to consider that the San Vicente geothermal wells have an amorphous silica scaling potential below 140°C and significant calcite scaling potential.

As presented before in Section 2.2, the best strategy to develop a geothermal resource is to build up the generation capacity in stages, and the project must be carefully explained in the field development plan (ESMAP, 2021).

The harnessing development plant for the San Vicente geothermal project is planned to be developed in two stages. The first stage has included the installation of the first unit (in the range of 10 MW) to harvest the steam available to date from wells SV-5A and SV-5B and continuing with the drilling work of the wells to produce the required steam for the second unit to be installed in the second stage (in the range of 20 MW). The second stage will also include the drilling work for the production and reinjections wells required to complete the estimated capacity. Following this stepwise strategy, the goal is to fully develop the field utilising the most suitable technology for each stage until its estimated capacity of 30 MW is reached (LAGEO, 2020).

In order to evaluate the power capacity of the project for each stage, this report will model three types of power plant technologies. The modelling will include a single flash power plant, which is often the first power plant installed in a new liquid-dominated geothermal field (DiPippo, 2016b). At the same time, the back pressure and binary cycle technologies will be modelled. The thermodynamic models of the geothermal power plants carried out in this report are the most common cycles installed in the Central America region (Estévez, 2012). The power plants modelling will be presented in Chapter 6 (Engineering and technology) and the evaluation of the project costs and the financial models will be made in Chapter 7. The finaicial model will determine which power plant application is the best option for developing the project stages based on the selection made in Chapter 6.

Chapter 6

Engineering and technology

A critical decision for project owners to develop new geothermal projects is to select the most suitable geothermal power plant configuration to maximise and manage the reservoir utilisation, considering how to develop it in sustainable ways, mainly to produce electricity. At the same time, to take advantage of residual heat that can be used for direct use applications to create benefits for the communities in the surrounding areas of the geothermal project. Geothermal heat is an energy that cannot be exported and needs to be utilised locally. This Chapter presents the engineering and technology of the preliminary design proposed for the San Vicente geothermal power plant project, describing and specifying its major components following the reservoir characteristics and the harnessing plan presented in previous chapters.

Geothermal projects are designed for each geothermal field, and power plants cannot be ordered in advance. That is why estimating and testing how much steam is available before seeking offers is an important step. Oversizing and overbuilding the power plant from the field power capacity has consequences to the project owner and its investors, creating risk in financing the current and future projects. The irony is that a properly sized, but smaller plant has a much better chance of being seen as a success (DiPippo, 2016b). Oversizing or properly sizing with smaller power plants depends on each project and needs to be financially evaluated to help the decision-maker choose the most suitable development option for the power plant to be installed.

Another challenge is that the technology available in the geothermal industry is limited, and most of the technology has been adapted from the oil and gas industry manufacturers. Moreover, learning from good and bad experiences shared from different countries, project developers, and operators of geothermal facilities have been important inputs for this industry.

A feasibility study discusses the choice of technology that has been selected for the power plant project development. Additionally, it is important to present the power plant main technical parameters, boundary conditions, and describe factors like non-condensable gases content, as well as any other aspect that might affect the choice of the conversion technology for the project. Finally, the basic engineering should be summarised with the most common design criteria. This basic engineering for a feasibility study is usually complete and includes wells, the power plant, the gathering systems, and transmission lines. Nevertheless, the project maturity level of the design and its cost can be determined using the guidelines of the American Association of Cost Engineering (AACE) (ESMAP, 2021).

6.1 Geothermal power plants

The principal elements of geothermal power plants are the wells, pipelines, gathering systems, separators, flashers, turbines, heat exchangers, condensers, cooling towers, and pumps (DiPippo, 2016a). In the geothermal industry, many different design options are available for these principal elements. In this section, a brief description of these components is presented. At the same time, some of the design options for the San Vicente power plant project are included.

The wells in the San Vicente project are designed to be a directional, full commercial size aiming at a specific target and hitting multiple fractures in the same well with the objective to increase the well capacity output. The depth of the wells will be designed between 1800 and 2000 m in measure distance. The San Vicente well pads are designed with the capacity to drill up to four geothermal wells from the same location. The multi-well pad has the advantage to reduce the cost associated with the pad and access road construction, water supply, and drilling rig mobility. At the same time, the construction costs of the gathering system are reduced. Figure 6-1 shows the technical profile of the well SV-5A.

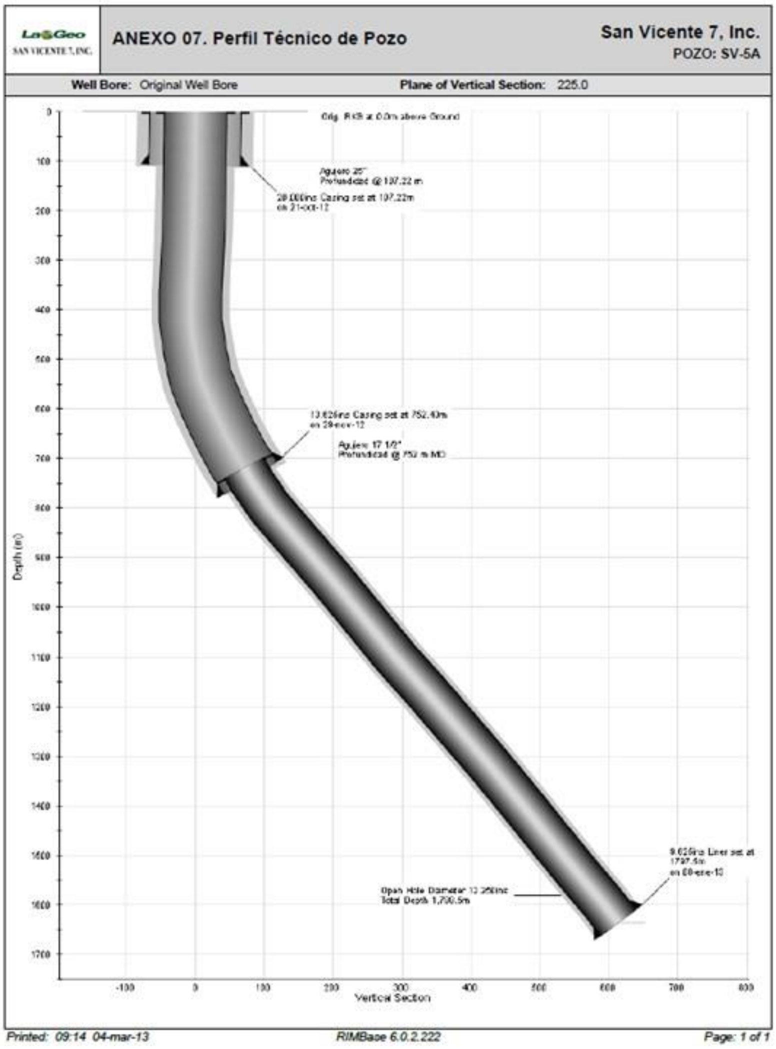
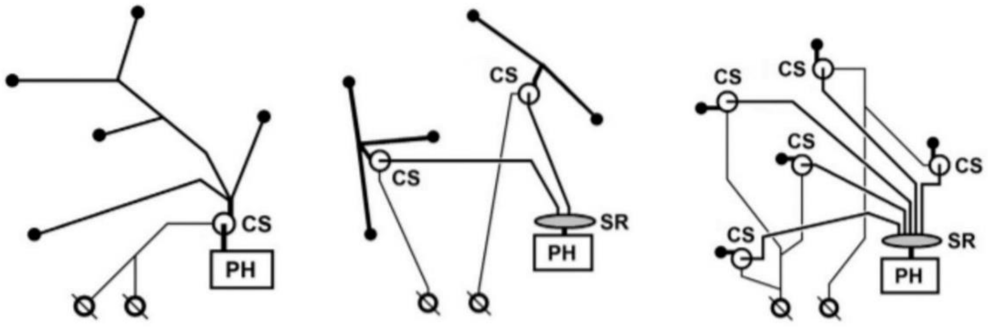


Figure 6-1 Directional "J" well-drilling profile of well SV-5A (LAGEO, 2013)

The pipelines and the location of the separation stations, known as a gathering system, is part of the general design of the power plant. A gathering system is needed to transport the geothermal fluid from the production wells to the power plant and then to the reinjection wells and point of disposal. The possible arrangements of the gathering system are shown in Figure 6-2, where the filled circles are production wells, open circles are injection wells, CS is the cyclone separator, PH is the power plant, and SR is the steam receiver.



1. 2. 3.

Figure 6-2 Possible arrangements of gathering systems. 1. Two-phase 2. Satellite separator station 3. Individual wellhead separator. (DiPippo, 2016b)

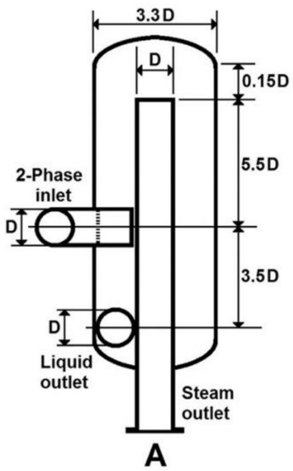
For the San Vicente geothermal project, arrangements with a satellite separation station will be proposed, and one separator will be installed for every two wells located in the well pad. This design criterion reduces the number of vessels and other equipment installed in the well pads leading to a reduction in capital costs. A significant relationship that the project designer needs to consider is the balance between thermodynamics and economics. Then, the pressure drop for the steam lines depends on the frictional pressure drop related to the pipe diameter and length. Since the density of steam is relatively low, the change in pressure due to changes in pipe elevation is smaller than the friction factor. Finally, the steam and brine velocities in pipelines are typically 40 m/s for steam pipelines and in the range of 2 to 3 m/s for the brine pipelines (DiPippo, 2016b; Henríquez & Aguirre, 2011).

It is important to separate the geothermal fluid efficiently before the steam enters the turbine. Generally, the quality of the steam entering the turbine should be at least 99.99 % dry to avoid scaling and/or erosion of piping and turbine components. The simple vertical Webre-type separator has been used in the geothermal industry since 1995, designed based on a combination of theory and empirical correlations studied by Lazalde-Crabtree. Alternatively, a variation on these designs is used in Iceland with a horizontal orientation. Horizontal separators need an extensive plan area. They are not as tall as vertical ones, making it easier to house them inside buildings, access the level instruments, and seem to be more useful for a colder climate. Additionally, Table 6-1 shows the advantages and disadvantages of each type of separator (DiPippo, 2016b).

Table 6-1 Separator design advantages and disadvantages

Separator type	Advantages	Disadvantages
Vertical design	Cleaner steam Sharp cut-off Wider pressure range Less expensive to build and install Easier maintenance	Size limitation Height of construction
Horizontal design	No size limitation Greater throughput per vessel	Horizontal mist eliminator are needed for high quality steam Greater maintenance

For the San Vicente project, vertical separators are selected and designed following the recommended guidelines developed by Lazalde-Crabtree to achieve a very high level of steam quality. The recommended geometry and the guideline are presented in Figure 6-3.



Parameter	Value
Maximum steam velocity at the two-phase inlet pipe	45
Recommended range of steam velocity at the two-phase inlet pipe	25 - 40
Maximum upward annular steam velocity inside cyclone	4.5
Recommended range of upward annular steam velocity inside cyclone	2.5 - 4

The units of these parameters are in m/s

Figure 6-3 Separator design guideline (DiPippo, 2016b)

The geothermal fluid is separated into saturated vapour (steam) and saturated liquid (brine). The separation process is at constant pressure. Geothermal power plants use steam turbines, where the saturated steam is expanded, and its energy is transformed into mechanical energy in the turbine shaft.

The turbines are one of the major drivers in the cost and schedule of geothermal projects. Figure 6-4 shows three geothermal turbine configurations: Bottom exhaust, top exhaust, and axial exhaust. The bottom exhaust turbines have been historically been used for large units from 50 to 55 MW. They also provide a low-pressure drop in the condenser but require a taller power plant building and take longer to construct. Historically, smaller units were top exhaust. This configuration allows shorter construction periods and easier access for operation and maintenance activities, but reduces unit performance due to a significant pressure drop in the condenser. The turbines with axial exhaust configurations allow for smaller power plant buildings, are easier for maintenance activities, and have the lowest exhaust pressure drop, but have several constraints that must be addressed in the design. One of which is the single flow design.

The turbines used in geothermal projects must be made of corrosion resistant material due to the presence of gases, such as hydrogen sulfide that can attack normal steel. Generally, 12% chromium steel is used for steam path components. Moreover, in the lower pressure stages of the geothermal turbines, significant amounts of moisture appear in the steam path, causing erosion in the blades of these stages. To reinforce these areas, cobalt-rich alloy strips, such as Stellite, are coated on these critical areas to protect them from damage. Due to the corrosive effects of the geothermal fluids, it is a good practice in the industry to conduct in situ material testing before deciding on the selection of materials for the plant (DiPippo, 2016b). This report proposes the top exhaust turbine configuration for the San Vicente power plant project as an initial step. However, the final design will depend on the turbine manufacturer evaluation, based on all the technical data provided by the project owner during the tendering process.

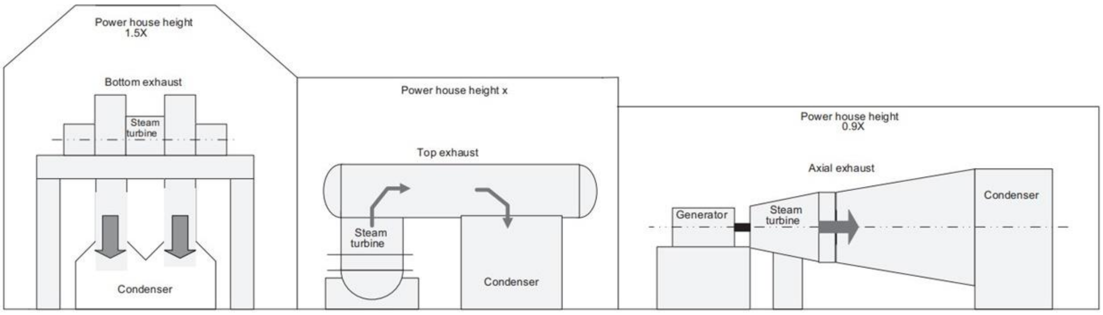


Figure 6-4 Turbine exhaust configuration (Harvey & Wallace, 2016)

The steam exhausted from the turbine is cooled in the condenser by extracting energy creating a vacuum condition in the condenser. The main goal of the condenser in a geothermal power plant cycle is to generate maximum power output at high efficiency. Theoretically, the condenser increases the enthalpy drop and the turbine power output by lowering the turbine outlet pressure. Another goal is to condense the steam because it requires less work to pump an incompressible liquid than compressible steam (gas) in the geothermal generation cycle.

Basically, two types of condensers are used in the geothermal industry: the surface type and the direct contact condenser. Power plants now employ surface condensers in which the geothermal steam passes through the shell side, and the cooling water passes through the tube side. The cooling water is pumped from the cooling tower by circulating water pumps in cycles using surface condensers. Warm water returns to the cooling tower. While the turbine exhaust steam forms condensate on the shell side, which is pumped to the reinjection well and/or pumped to the cooling tower using a condensate pump. In the direct contact condenser, the exhausted steam mixes with cold water from the cooling tower creating the vacuum, increasing the turbine performance. The condensate mixture is pumped from the condenser to the cooling tower by hotwell pumps.

There are many tradeoffs in the selection and design of the direct contact versus surface condensers. For example, a direct contact condenser has lower costs and is simpler in construction and design than the surface condenser. For this reason, the design and selection of the appropriate type of condenser are made by evaluating each project’s requirements. Table 6-2 shows some advantages that can be considered during project design to select the type of condenser to be used (DiPippo, 2016a).

Table 6-2 Advantages for direct contact and surface condensers

Type	Advantages
Direct-contact condenser	More efficient heat exchange Lower cost Less prone to failing
Surface condenser	Lower parasitic loads Higher purity stream of water condensate More effective removal and treatment of NCG Greater flexibility in plant layout

The condenser type proposed for the San Vicente power plant project in this report will be the surface condenser type based on the advantages presented above.

The cooling systems must be designed to accommodate the heat load from the condensing steam to the heat sink (air and/or water) at a low temperature. The most common cooling systems in the geothermal industry are the recirculating wet towers and the dry cooling towers. Over time, the recirculating wet tower systems have been the preferred cooling system in the geothermal industry. Wood and concrete wet cooling towers for flash plants have been widely used over the past decades. Moreover, towers built with fibreglass-reinforced polyester (FRP) are becoming increasingly popular. Cooling towers using wood structures seem economical but require maintenance to keep the wood damp, safe, and in good operating conditions. Concrete towers are more robust but require extensive civil work. The concrete tower may be costly and present construction and safety challenges depending on the project location. The FRP towers provide less structural mass, and for this reason, the structure and the mechanical equipment need to be designed and monitored to prevent unwanted vibration. The FRP tower cost is sensitive to the oil price (DiPippo, 2016a).

The installation of air cooling systems has increased and is a standard option for conventional fossil combined cycle plants, especially in arid areas where there is a makeup water shortage for wet cooling towers. The air cooling systems offer the environmental benefit of reducing the power plant water consumption, and the plant sitting flexibility is greater. Typically, the capital and operation costs of the air cooling system are comparatively higher than the wet cooling system’s because these systems require more types of equipment, consume more power, and cover more land area. However, due to water usage costs and water availability, according to Njoku and Diemuodeke, the levelised costs of electricity generation for plants with wet and dry systems would become equal. A binary plant can use air cooling. While air cooling for flash plants is not impossible, it has certain limitations, like removing large quantities of NCG, resulting in not yet being widely used in the geothermal industry. The air cooling units would have more geofluid consumption per unit of net power output but would return, theoretically, 100 % of the geofluid consumed to the reservoir (DiPippo, 2016a; Njoku & Diemuodeke, 2021). For the San Vicente project, the single flash units are proposed to use wet cooling systems, and the binary cycles are proposed to use air cooling systems for this report.

Table 6-3 summarises the first approach of the proposed design for some elements that will be part of the San Vicente power plant project:

Table 6-3 Proposal design for elements to compound the San Vicente geothermal project

Description	Design proposal
Drilling well pads	Designed with room to build up to four cellars
Geothermal wells	Directional and full commercial size
Gathering system	Satellite separation station with one separator for two wells
Separator design	Vertical Webre-type separator
Velocity in pipelines	Steam 40 m/s and brine between 2 - 3 m/s
Turbine exhaust configuration	Top exhaust
Condenser type	Surface condenser
Cooling system for single flash unit	Wet cooling system
Cooling system for binary cycle unit	Dry cooling system

6.2 Power plant models

In order to evaluate the power plant designs and power capacity of the San Vicente project, this report will present the result of modelling three types of power plant technologies following the harnessing plan, which defines developing the project in two stages. Table 6-4 shows the number of wells available for each stage and the technologies to be evaluated.

Table 6-4 Harvesting plan and the technologies to modelling in each stage

Item	Stage I	Stage II
Number of production wells available	2	6
Number of reinjection wells available	2	3
Power plant technologies	Backpressure Single flash Binary	Single flash Binary

For the first stage, the cycles to be evaluated will be the back pressure unit, the single flash unit, and the binary cycle unit. In this first stage, the main objective is to utilise the geofluid available from wells SV-5A and SV-5B. The drilling well pad SV-5 is the proposed location for the installation of the power plant as a wellhead unit. The second stage will present the results of modelling the single flash and the binary cycle unit, assuming the geofluid production of the existing wells adding the wells required to complete the estimated capacity of the reservoir, utilising the data presented in the drilling strategy, Section 5.3.2. In this report, the EES computer program was used for thermodynamic calculations for different cycle modelling. This program is a general equation solver that solves thousands of algebraic and differential equations. The program provides a high accuracy thermodynamic property database for the fluids used in this report (*EES: Engineering Equation Solver | F-Chart Software : Engineering Software*, 2021).

6.2.1 Back pressure power plants – Stage I

The consideration to install a wellhead power plant in the early stage of the geothermal project is a strategy to improve return on investment compared with the time required to develop the estimated capacity of the project with a large unit without cash flow. At the same time, installing a wellhead unit can serve as a long term flow test for productions wells and demonstrate the reservoir production capacity for installing a more efficient centralised unit. The wellhead units used are back pressure, condenser and binary cycle technologies (DiPippo, 2016a). The most straightforward geothermal system available in the geothermal industry is a well-driving back pressure steam turbine. The configuration of this type of system is shown in Figure 6-5.

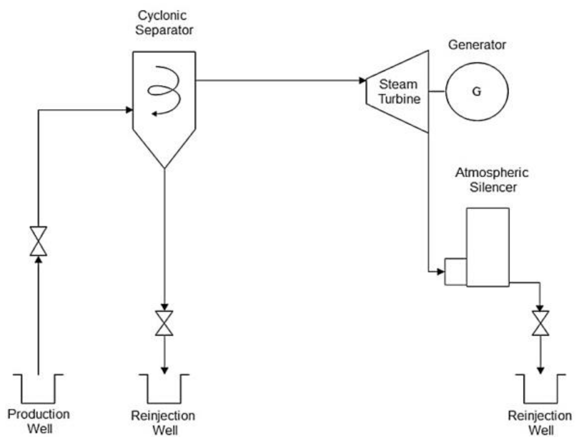


Figure 6-5 Back pressure system schematic

The geothermal fluid, a hot water and steam mixture, flows from the production well to a highly efficient cyclone separator. The separated steam, at saturated conditions, goes from the cyclone separator to drive the turbine, and the turbine drives an electrical generator to produce electricity. The spent steam in the turbine is exhausted to the atmosphere, at the local atmospheric pressure. The separated water (brine at saturated conditions) in this application is reinjected into a geothermal well. Using EES to model the back pressure cycle, the turbine power output is determined by varying the separation pressure. Figure 6-6 shows the proposed utilisation process flow diagram to develop Stage 1 with a back pressure unit.

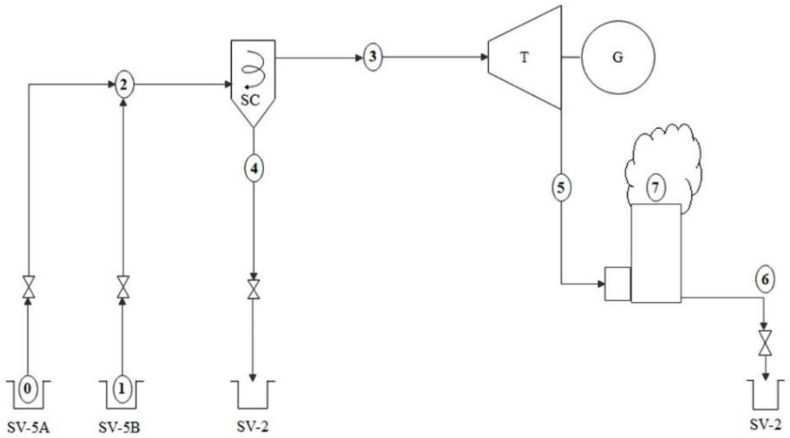


Figure 6-6 Proposal back pressure cycle schematic for Stage I

This report assumes that state 0 and 1 are the condition of the geothermal reservoir near the bottom of the wells and has a liquid phase at saturation condition. The process, where the constant fluid flows through the wells from the reservoir, is assumed to be isenthalpic. The assumptions used in this model are summarised in Table 6-5.

Table 6-5 Assumptions of the geothermal back pressure model application

System	Parameter	Unit	Value
Reservoir	Productive curve well SV-5A	$m_{total} = f_{(P)}$	m[0] = (41.0331 + 0.0117714 * P - 0.0000114286 * P^2)
	Productive curve well SV-5B		m[1] = (31 + 0.0117714 * P - 0.0000114286 * P^2)
State 0	Enthalpy	KJ/Kg	1600
SV-5A	Temperature	°C	256
State 1	Enthalpy	KJ/Kg	1300
SV-5B	Temperature	°C	238
Power plant	Turbine isentropic efficiency	%	79.8 *
	Atmospheric pressure	KPa	90.85

* Efficiency value of two back pressure units of 6.5 MW installed at Wairakei power plant (DiPippo, 2016b).
**The P-value in the productive curves is the separation pressure.
***Pressure losses in pipelines and other equipment are neglected.

The results of the model are shown in Figure 6-7 and present the optimum gross power output at different separation pressures. The highest gross power output from the back pressure cycle is reached at a separation pressure of 900 kPa (9 bar), producing 6.4 MW of power.

The wells utilised in this application are grouped to deliver steam from the cyclone separators at a common pressure. For that reason, the selection of the separation pressure has an important effect on the cycle performance in terms of power output. Nevertheless, in general, back pressure or wellhead steam turbines can operate more closely tailored to the productivity curve of one well (DiPippo, 2016a).

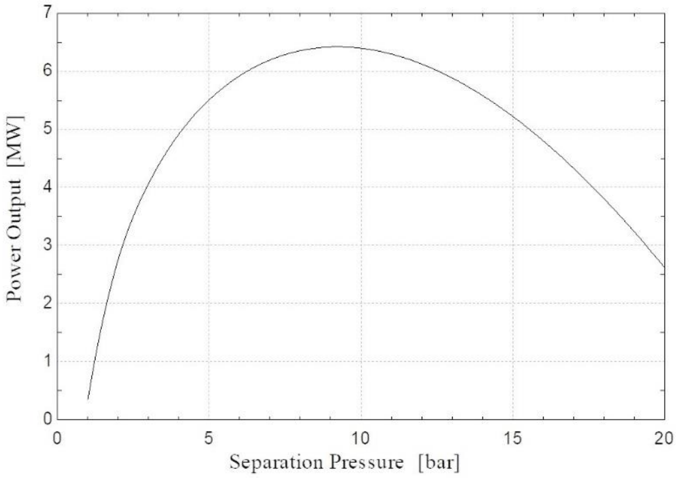
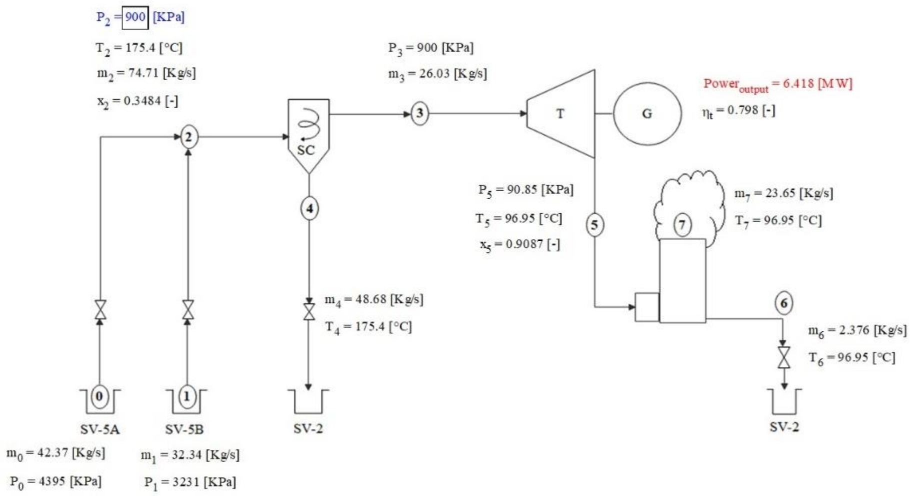


Figure 6-7 Gross power output at different separator pressure for the back pressure cycle

The modelling mass balance analysis and thermodynamic properties using the optimum separation pressure of 900 kPa are shown in Table 6-6.

Table 6-6 Parametric table and process flow diagram for a back pressure cycle

Property	Enthalpy	Mass	Pressure	Entropy	Temperature	Quality
Units	[KJ/Kg]	[Kg/s]	[KPa]	[KJ/Kg*°C]	[°C]	[-]
Point [i]	h[i]	m[i]	P[i]	s[i]	T[i]	x[i]
0	1600.00	42.37	4395.00	3.77	256.00	0.00
1	1300.00	32.34	3231.00	3.22	238.00	0.00
2	1450.00	74.71	900.00	3.67	175.40	0.35
3	2773.00	26.03	900.00	6.62	175.40	1.00
4	742.60	48.68	900.00	2.09	175.40	0.00
5	2464.00	26.03	90.85	6.62	96.95	0.91
6	406.30	2.38	90.85	1.27	96.95	0.00
7	2671.00	23.65	90.85	7.39	96.95	1.00



The reinjection brine flow produced by this application is 51 kg/s, which is the sum of mass values determined in states 4 and 6. This amount of brine is proposed to be reinjected in wells SV-2A and SV-2B, defined as reinjection wells for the San Vicente geothermal project. These wells are sited in the drilling well pad SV-2.

6.2.2 Single flash power plant- Stage I

The single flash power plant technology has been and continues to be the pillar to develop geothermal projects worldwide. The terminology "single flash system" indicates that the geothermal fluid has experienced a single flash process. The flash process can occur in different places. For a new project, the flashing process occurs in the well initially, but with the utilisation time due to pressure changes, the flashpoint moves down to the well or even enters the formation (DiPippo, 2016b).

Figure 6-8 shows the proposed single flash cycle flow diagram in Stage I to develop the San Vicente project. The geothermal fluid flows from the production wells to the cyclone separator. The separated steam goes from the cyclone separator to drive the turbine, and the turbine drives an electrical generator to produce electricity. The spent steam in the turbine is exhausted to heat rejection system, consisting of the surface condenser, circulation water pumps, and a wet cooling tower. The separated brine and the condensate in this application are reinjected into a geothermal well.

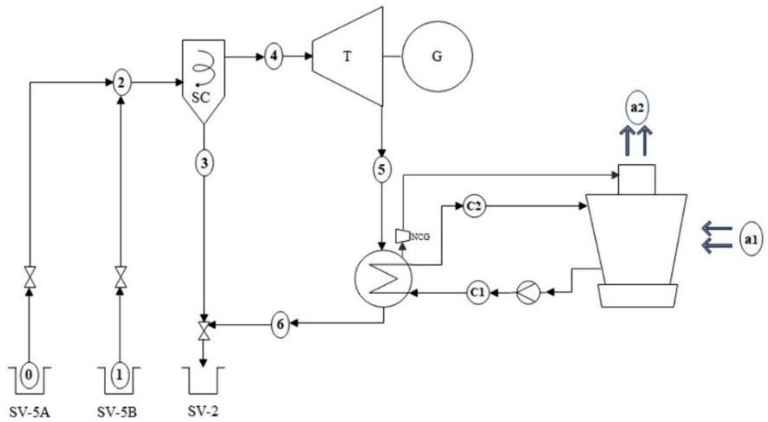


Figure 6-8 Single flash cycle schematic

The main goal to use a condenser in a single flash cycle is to generate maximum power output at high efficiency. The condenser increases the enthalpy drop and the turbine power output by lowering the turbine outlet pressure. The lower the condenser pressure, the higher the efficiency and power are. Due to this, the parasitic loads, equipment, and construction costs need to be evaluated simultaneously with the condenser pressure design (Bekdemir et al., 2003; Saito, 2010).

This report presents a single flash power plant optimisation based on the lecture notes of the course Power Plant Design at Reykjavik University (Harvey, 2019a). Here, the main focus of the power plant optimization is to determine the optimum separation pressure, which maximises the power output. At the same time, it presents the assumption of the key parameters that affect the power plant performance, evaluating the operation points that must be considered to design the power plant's major equipment. This evaluation looks at the best combination of parameters to obtain low initial project capital costs, high cycle efficiency, and low project operation costs. In simple words, the design is based on both thermodynamic and economic analysis.

The performance of geothermal power plants is directly affected by the production well curves and the atmospheric wet-bulb temperature (T_{WB}). Then, in optimising a single flash power plant, the reservoir pressure, wet bulb temperature, and condenser pressure need to be evaluated for each project. The condenser pressure parameter strongly drives the size and design of the power plant's major equipment.

The geothermal power plant equipment manufacturer performs plant optimisation at Phase 4 (Project review, planning, and design) of the project development to offer a power plant configuration with maximum power output at low cost, specifying the operation conditions and requirements (Saito, 2010). In the preparation of a feasibility study, a techno-economic optimisation is not necessarily fully developed. However, it is important to analyse the cycle and define the key parameters to estimate the power plant output before the tendering process starts.

The optimisation process of the overall geothermal power plant has many variables to be considered. This report is modelling the cycle, fixing the separation pressure, ambient temperature conditions, and the terminal temperature difference (TTD) of the condenser to select the most suitable value of the condensing pressure with a reasonable tradeoff between the power output and cooling water flow rate of the power plant.

Additionally, the "Range" of the cooling system, that is, the difference between the cooling water temperature and the hot water leaving the condenser, drives the design parameter of the cooling water flow rate needed to be circulated by the hotwell pumps in the cycle to achieve the condensing temperature. The range is another parameter that affects capital costs. In order to model the single flash cycle to define the most suitable condensing pressure for the power plant, an evaluation of the turbine output and the cooling water flow rate has been done using the assumptions shown in Table 6-7.

Table 6-7 Assumptions to determine the condensing pressure for the single flash application

System	Parameter	Unit	Value
Reservoir	Productive curve well SV-5A	$m_{total} = f_{(P)}$	m[0] = 41.0331 + 0.0117714 * P - 0.0000114286 *P^2
	Productive curve well SV-5B		m[1] = 31 + 0.0117714 * P - 0.0000114286 *P5^2
State 0 SV-5A	Enthalpy	KJ/Kg	1600
	Temperature	°C	256
State 1 SV-5B	Enthalpy	KJ/Kg	1300
	Temperature	°C	238
Power plant	Turbine isentropic efficiency	%	82.2*
	Separation pressure	kPa	700
	Atmospheric pressure	kPa	90.85
	Ambient temperature	°C	22.23 **
	Wet bulb temperature	°C	20.35
	Relative humidity	%	85
	Terminal temperature difference	°C	5
	Temperature of cooling water	°C	25

* Efficiency value of two single flash units of 28 MW installed at Berlín power plant (DiPippo, 2016b).
** Ambient temperature (LAGEO, 2020)
The P-value in the productive curves is the separation pressure.
Pressure losses in pipelines and other equipment are neglected.

States 0 and 1 are the condition of the geothermal reservoir near the bottom of the wells and have a liquid phase at saturation condition. Steam exhausted from the turbine is cooled in a surface condenser using cold water from the cooling tower at 25°C. This cooling water temperature is set close to 5°C higher than the wet bulb temperature at the project location. This difference is known as the "Approach" of the cooling system. The TTD determines the heat exchange process. Therefore, the hot water temperature leaving the condenser must not exceed the condensing temperature. This temperature difference is assumed as 5°C. Additionally, it is assumed that the condensation process is at a constant temperature. Equation (6.1 determines the condensing temperature (T_5):

$$T_5 = T_{WB} + Range + Approach + TTD \tag{6.1}$$

The results of the single flash model at a separation pressure of 700 kPa used to determine the most suitable condenser pressure are shown in Figure 6-9. When a lower condenser pressure is selected, the power output increases and a higher cooling water flow rate is required. At the same time, lower condensing pressure means that a large cooling water system is required. For example, in Figure 6-9, when the cooling water mass flow starts to rise dramatically at 7 kPa, the power plant will require more large equipment, meaning a higher capital cost. At values of condensing pressure below 7 kPa, these capital costs related to the higher cooling water flow rate require the design of large hotwell pumps, cooling water pipes, a bigger condenser, and a large NCG extraction system making the project less feasible.

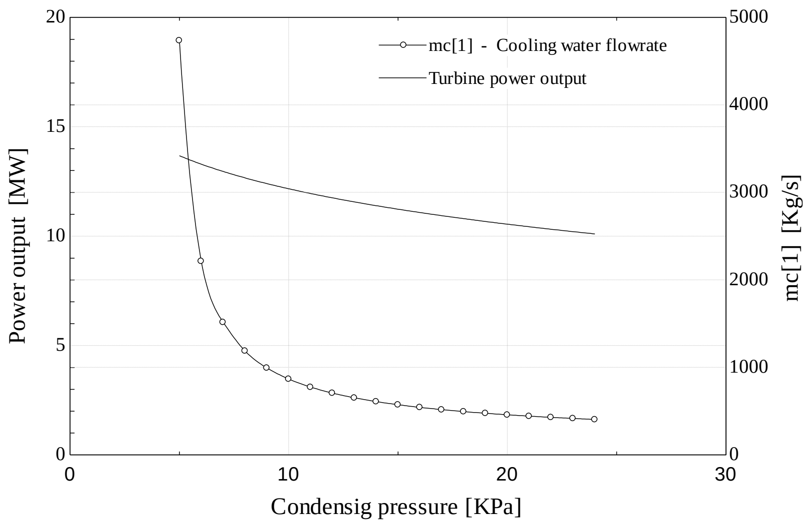


Figure 6-9 Condenser pressure optimisation

In single flash power plants, the condensing pressure is selected between 8 to 13 kPa. Figure 6-10 shows the condensing pressure for power plants using a single flash cycle.

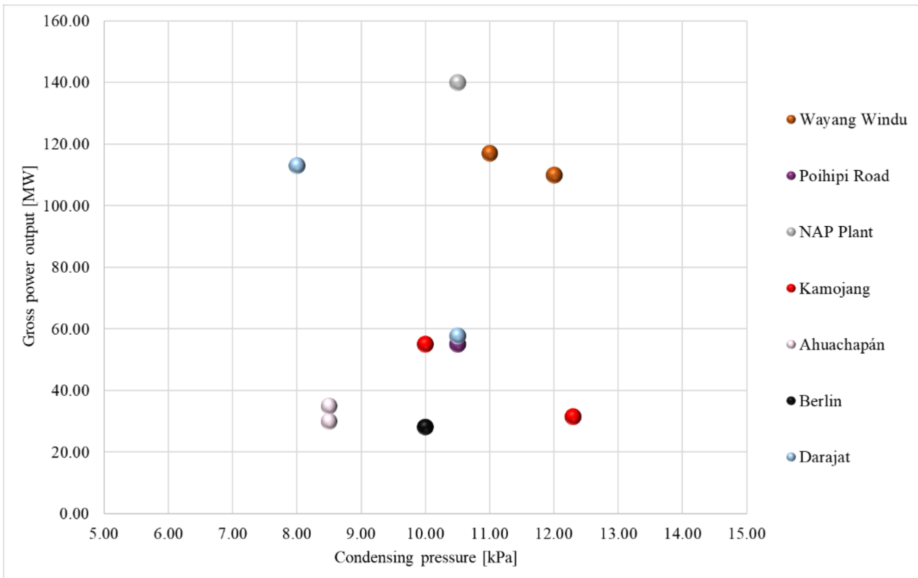


Figure 6-10 Installed power plants using a single flash cycle (DiPippo, 2016b)

In this report, the condensing pressure will be defined at 8 kPa, a value that generates high power output and a reasonable cooling water flow rate. Additionally, the condenser pressure selected results in an acceptable value of capital cost and is within the design points range for geothermal steam turbines operating worldwide.

Once the condenser pressure is selected, the next parameter that will be briefly discussed is the Range. The Range is another parameter that affects the power plant capital cost. The power plant designer defines this parameter to decide the amount of water that circulates in the cycle and the associated size of the power plant hotwell pumps. Figure 6-11 shows the relationship between the cooling water flow rate and the Range. Practically, if the cooling water flow rate is doubled, the Range is reduced approximately by half and the condensing temperature decreases. The most common values of the Range used by power plant designers are between 10 and 25 °C and hardly depend on the project location. Figure 6-12 shows some of the Range values used in single flash power plants worldwide.

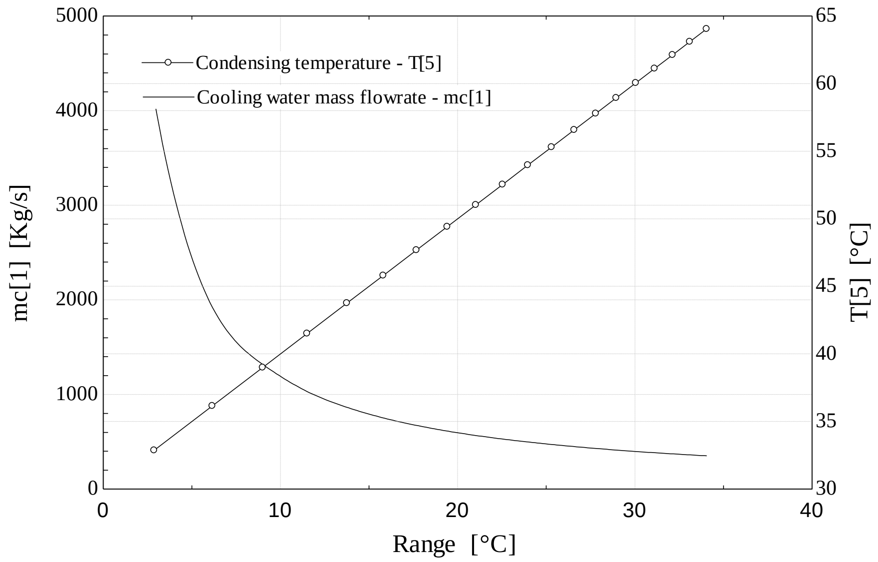


Figure 6-11 Relationship between the cooling water flow rate and the range of a single flash power plant

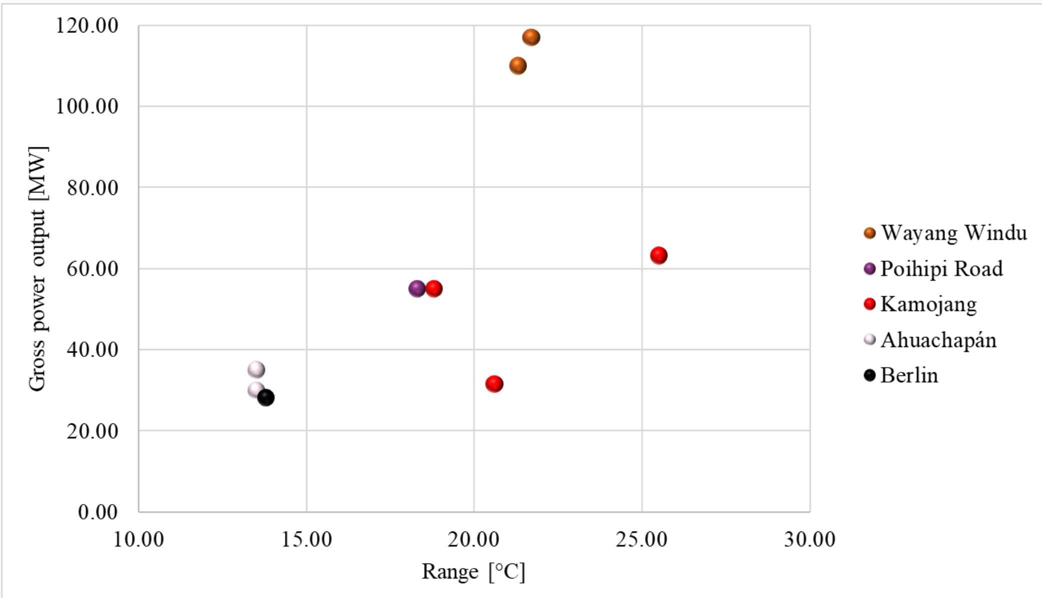


Figure 6-12 Range value for a single flash power plant installed worldwide (DiPippo, 2016b)

Using Equation (6.1, the Range in this model is equal to 11.51 °C due to the temperature in the condenser (T[5]) being the saturation temperature at the condensing pressure (P[5]). The task now is to determine the optimum separator pressure of the single flash cycle with the condenser pressure that has been set. The assumptions used to determine the optimum separator are summarised in Table 6-8.

Table 6-8 Assumptions to determine the optimum separator pressure for the single flash application

System	Parameter	Unit	Value
Reservoir	Productive curve well SV-5A	$m_{total} = f_{(P)}$	m[0] = 41.0331 + 0.0117714 * P - 0.0000114286 *P^2
	Productive curve well SV-5B		m[4] = 31 + 0.0117714 * P - 0.0000114286 *P5^2
State 0 SV-5A	Enthalpy	KJ/Kg	1600
	Temperature	°C	256
State 1 SV-5B	Enthalpy	KJ/Kg	1300
	Temperature	°C	238
Power plant	Turbine isentropic efficiency	%	82.2*
	Atmospheric pressure	kPa	90.85
	Ambient temperature	°C	22.23 **
	Wet bulb temperature	°C	20.35
	Relative humidity	%	85
	Terminal temperature difference	°C	5
	Condenser pressure	kPa	8
	Temperature of cooling water	°C	25

Additionally, the report considers that the moisture limit in the turbine exhaust steam is not allowed to exceed 15% to avoid the erosion problem in the last stage of moving blades (DiPippo, 2016a; Saito, 2010). The results of the single flash model to determine the most suitable separation pressure are shown in Figure 6-13. The maximum gross power is at 700 kPa, generating 12.6 MW with an 85% quality of exhausted steam.

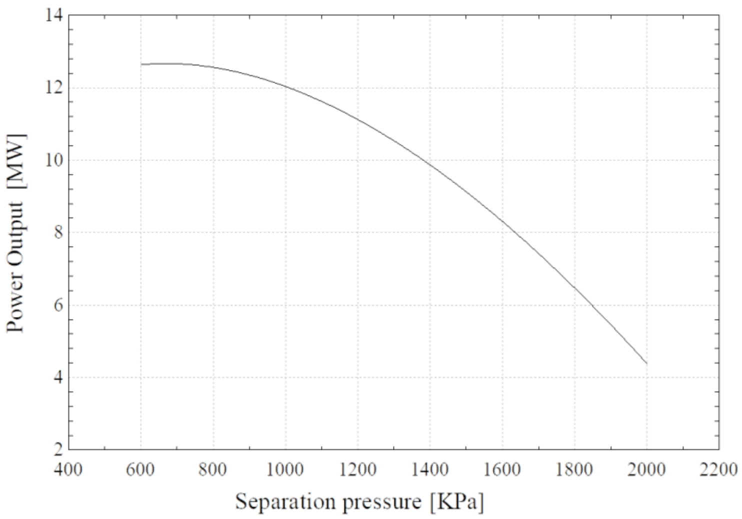


Figure 6-13 Gross power output at different separator pressure for a single flash cycle

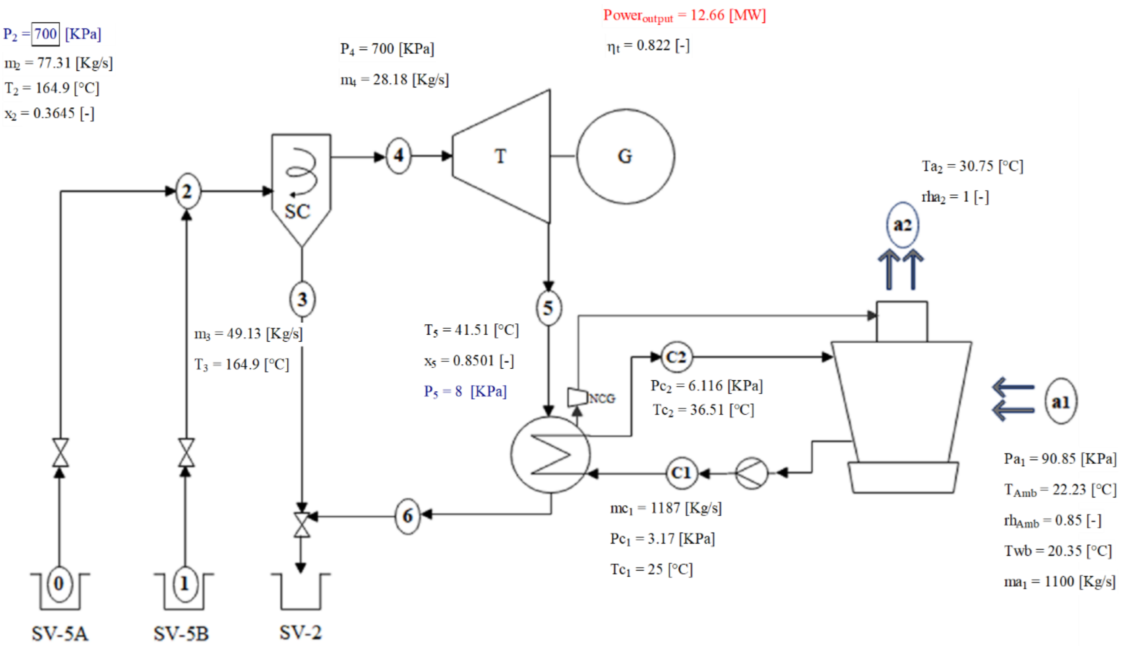
Single flash power plants generally perform at the separation pressure in the 600 – 2000 kPa range. As a result, the brine to be reinjected to the reservoir is already at elevated pressure, reducing the head requirements of brine injection pumps (DiPippo, 2016a). This report will propose the separation pressure at 700 kPa to guarantee enough turbine inlet pressure and the considerations taken when modelling the cycle to keep the associated plant costs at reasonable values. Additionally, for the separation pressure, this report will propose to reinject the brine taking advantage of the gravity head due to elevation changes between production and reinjection well pads.

The modelling mass balance analysis and thermodynamic properties using the separation pressure at 700 kPa and the condensing pressure of 8 kPa are shown in Table 6-9.

Table 6-9 Parametric tables for a single flash cycle

Property	Enthalpy	Mass	Pressure	Entropy	Temperature	Quality
Units	[KJ/Kg]	[Kg/s]	[KPa]	[KJ/Kg*°C]	[°C]	[-]
Point [i]	h[i]	m[i]	P[i]	s[i]	T[i]	x[i]
0	1600.00	43.67	4395	3.77	256.00	0.00
1	1300.00	33.64	3231	3.22	238.00	0.00
2	1450.00	77.31	700	3.71	164.90	0.36
3	697.00	49.13	700	1.99	164.90	0.00
4	2763.00	28.18	700	6.71	164.90	1.00
5	2216.00	28.18	8	7.08	41.51	0.85
6	173.80	28.18	8	0.59	41.51	0.00
C1	104.80	1187	3.17	0.37	25.00	0
C2	152.90	1170	6.12	0.53	36.51	0
a1	63.02	1100	90.85	5.86	22.23	0.85 *
a2	112.50	1100	90.85	6.03	30.75	1*

Points C1 and C2 are the cooling water parameters.
Points a1 and a2 are the air parameters.
* Relative humidity



The reinjection brine flow produced by this cycle is 77.31 kg/s, the sum of mass values determined in states 3 and 6, equivalent to saying that all the geofluid is returned to the reservoir. This amount of brine is proposed to be reinjected in wells SV-2A and SV-2B.

6.2.3 Binary cycle power plant – Stages I

A binary cycle power plant is a modification of a Rankine cycle where the working fluid is an organic fluid with a lower boiling point and higher vapour pressure than the water, along with all state points of the thermodynamic cycle.

The geothermal binary cycle power plant is formed by two cycles: the primary cycle that contains the geothermal fluid and the second cycle where the organic working fluid is enclosed. The primary cycle starts at the production wells and ends in the reinjection wells. The reservoir characteristics determine the geothermal fluid's temperature and flow rates in the primary cycle. The geothermal fluid can be either water (brine) or steam.

Figure 6-14 shows the proposed flow diagram of the binary cycle for Stage I to develop the San Vicente project. The main components for this power plant are the preheater (PH), evaporator (E), turbine (T), cooling system (CS) and the working fluid pump. The basic thermodynamic process of binary cycles is the Rankine cycle, where the vapour reaches a dry saturated condition in the evaporator and is condensed in the cooling system.

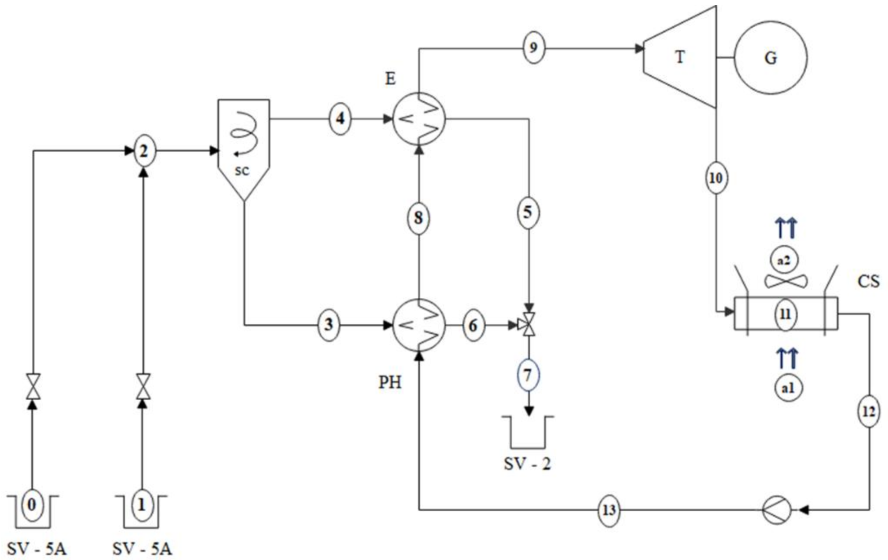


Figure 6-14 Binary cycle schematic

In the secondary cycle, the working fluid enters the pump at state 12 as a saturated liquid and is compressed isentropically to the operating pressure of the evaporator. The working fluid temperature increases during the isentropic compression process due to a slight decrease in the specific volume of the working fluid. The working fluid enters the preheater as a compressed liquid and leaves the evaporator as saturated vapour at state 9. Typically, the working fluid is delivered to its boiling point in the preheater during the heating-evaporating process. The preheater and evaporator are heat exchangers where the geofluid heat is transferred to the working fluid at a constant pressure. The evaporator is the section where the working fluid is vapourised at a constant temperature. This saturated condition ensures that no liquid droplets enter the turbine. The saturated vapour at state 9 enters the turbine, where it expands isentropically and produces work by rotating the turbine shaft connected to an electric generator. During the expansion process, the working fluid pressure and temperature drop to the values at state 10, where it goes to the condenser. At state 10, the working fluid is usually superheated vapour. The working fluid is condensed at a constant pressure by rejecting heat into the environment in the cooling system. The working fluid leaves the cooling system as saturated liquid and enters the working fluid pump, completing the cycle.

Silica scaling is an important design parameter for a binary cycle and geothermal power plants in general. Binary cycles as the main power plant or bottoming plant configuration, utilising geofluids from liquid dominated reservoirs, have to manage the silica saturation index (SSI) of the separated water (brine). The main concern is the silica scaling problem in the reinjection wells, thus limiting the power plant's efficiency and design due to maintaining the brine at or below the SSI limit. Typically, the scaling issue does not occur in production wells (DiPippo, 2016a; von Hirtz & Gallup, 2018).

Technology development and execution have made it possible to utilise geofluids that might not have other options. However, silica scaling becomes a problem once the brine is cooled and its SSI increases. Proven engineering strategies such as pH modification have been used to control and mitigate silica scale to increase the power output of the power plants. The brine outlet temperature can be 80 °C or less by implementing the pH modification process (von Hirtz & Gallup, 2018). This report proposes the brine reinjection temperature at 100 °C and, at the same time, a pH modification station to control and mitigate the silica scaling in the reinjection wells and power plant.

This report is modelling a binary power cycle using the steam and brine produced by wells SV-5A and SV-5B. The total brine mass flow produced for both wells will be used to preheat the working fluid, and the total steam mass flow will be used to vapourise the working fluid.

In order to determine the working separation pressure of the primary cycle, a simulation of well curves has been done, varying the separation pressure values to know the mass flow of steam and brine that can be produced for each well. These results help design the separation pressure for the geothermal cycle and are shown in Figure 6-15 and Figure 6-16.

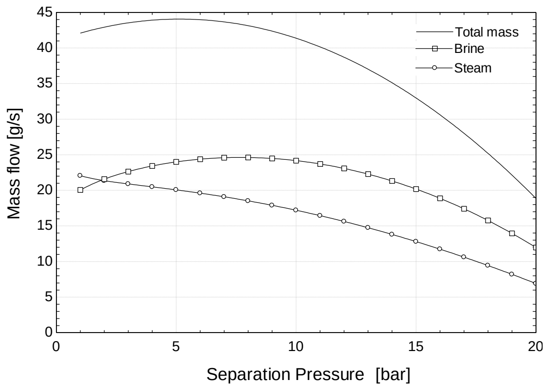


Figure 6-15 Mass flow production curves for well SV-5A

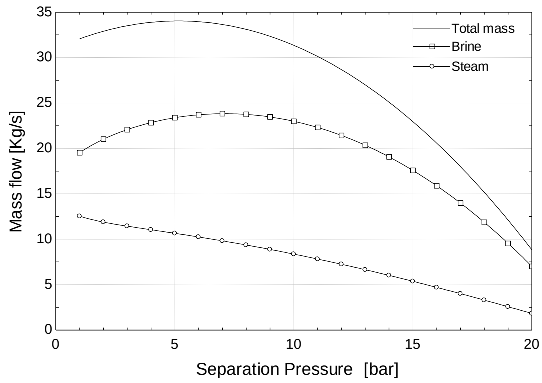


Figure 6-16 Mass flow production curves for well SV-5B

Since the slope of the steam production curves indicates variations close to 0.5 kg/s of steam for a change of 1 bar, this report will consider the value of separation pressure where both of the wells have an approximate maximum brine mass flow. The most suitable separation pressure for both wells is at 8 bar. At this pressure, the mass flow of steam and brine are 18.52 kg/s and 24.60 kg/s for well SV-5A, and 9.36 kg/s and 23.74 kg/s for well SV-5B, respectively.

The assumptions used in this report to model the binary cycle are summarised in Table 6-10.

Table 6-10 Assumptions of the binary cycle application

System	Parameter	Unit	Value
Reservoir	Productive curve well SV-5A	$m_{total} = f_{(P)}$	m[0] = (41.0331 + 0.0117714 * P - 0.0000114286 *(P)^2)
	Productive curve well SV-5B		m[1] = (31 + 0.0117714 * P - 0.0000114286 *(P)^2)
State 0 SV-5A	Enthalpy	KJ/Kg	1600
	Temperature	°C	256
State 1 SV-5B	Enthalpy	KJ/Kg	1300
	Temperature	°C	238
Power plant primary cycle	Separation pressure	KPa	800
	Reinjection temperature	°C	100
Power plant secondary cycle	Working fluid	-	Isopentane
	Turbine isentropic efficiency	%	80.4 *
	Pump isentropic efficiency	%	75
	Ambient temperature	°C	22.23 **
	Atmospheric pressure	kPa	90.85 **
	Relative humidity	%	85 **
	Wet bulb temperature	°C	20.35
	Pich-point temperature difference (TPP)	°C	5 ***
	Terminal temperature difference (TTD)	°C	5 ****

* Efficiency value of a binary unit of 9.2 MW installed at Belín power plant (DiPippo, 2016b)
**Local atmospheric conditions (LAGEO, 2020)
*** The point of closest approach between the brine cooling line and the working fluid heating line is called the pinch-point, TPP; typically, this temperature difference is about 5 °C (DiPippo, 2016a)
**** The highest temperature of the cooling air must not exceed the condensing temperature in the cooling system (TTD).

The working fluid selection for a binary power cycle is critical to cycle performance and depends on the geothermal conditions, considerations of health, safety, costs and environmental impact, among other factors (DiPippo, 2016a). In this report, the working fluid selection based its design criterion on the previous project owner experience with the first binary cycle using isopentane operating in the Berlín power plant (Monroy, 2013). This design criterion reduces the necessity to invest in the storage capacity of the working fluid for a new project due to its existing capacity and can be used by the project owner to supply both power plants.

Using EES to model this power plant cycle, the turbine gross power output is determined by varying the condensing pressure. The results of this modelling are shown in Figure 6-17, and it is clear to identify that the lower the condensing pressure, the greater the power that the cycle can generate. At the same time, as was presented in the single flash cycle, lower condensing pressure means that a large cooling system is required. In Figure 6-17 when the cooling air mass flow rate starts to rise dramatically at 110 kPa, the power plant will require large equipment, meaning a higher capital cost.

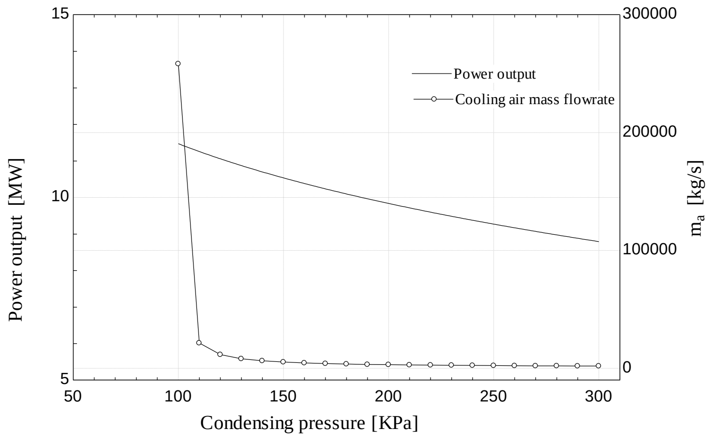


Figure 6-17 Turbine power output and cooling air mass flow at different condensing pressure

In this report, the condensing pressure will be defined at 180 kPa, a value that generates 10 MW of gross power and requires a reasonable cooling air mass flowrate. The task now is to determine the turbine working pressure of the binary cycle with the condenser pressure that has been determined and the assumptions presented in Table 6-10.

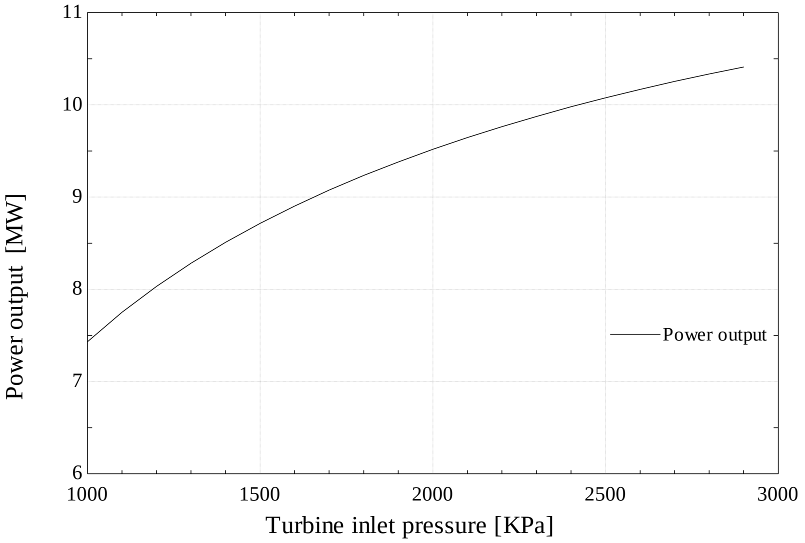


Figure 6-18 Gross power output at different turbine inlet pressure for a binary cycle using isopentane as a working fluid

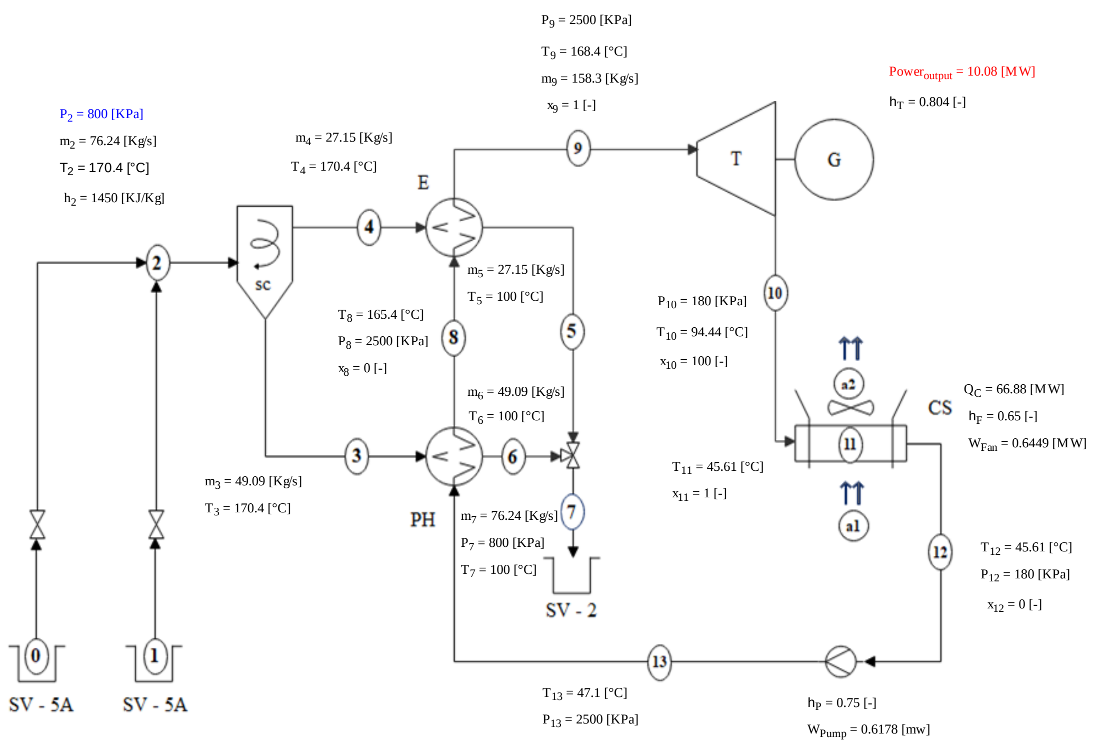
This report will propose the turbine inlet pressure at 2,500 kPa to generate gross power close to the goal of this stage of the project and keep the associated plant costs at reasonable values.

The modelling mass balance analysis and thermodynamic properties using the assumptions presented in Table 6-10, and the condensing pressure at 180 kPa and the turbine inlet pressure at 2,500 kPa for the working fluid cycle, are shown in Table 6-11.

The reinjection brine flow produced by this cycle is 76.24 kg/s, equivalent to saying that all the geofluid is returned to the reservoir. This amount of brine is proposed to be reinjected in wells SV-2A and SV-2B.

Table 6-11 Parametric tables for a binary cycle

Property	Enthalpy	Mass	Pressure	Entropy	Temperature	Quality
Units	[KJ/Kg]	[Kg/s]	[KPa]	[KJ/Kg*°C]	[°C]	[-]
Point [i]	h[i]	m[i]	P[i]	s[i]	T[i]	x[i]
0	1600.00	43.14	4395.00	3.77	256.00	0.00
1	1300.00	33.10	3231.00	3.22	238.00	0.00
2	1450.00	76.24	800.00	3.69	170.40	0.36
3	720.90	49.09	800.00	2.05	170.40	0.00
4	2768.00	27.15	800.00	6.66	170.40	1.00
5	419.20	27.15	800.00	1.31	100.00	0.00
6	419.20	49.09	800.00	1.31	100.00	0.00
7	419.20	76.24	800.00	1.31	100.00	0.00
8	49.96	158.30	2500.00	-0.62	165.40	0.00
9	199.40	158.30	2500.00	-0.28	168.40	1.00
10	120.20	158.30	180.00	-0.23	94.44	100.00
11	26.03	158.30	180.00	-0.51	45.61	1.00
12	-302.20	158.30	180.00	-1.54	45.61	0.00
13	-297.00	158.30	2500.00	-1.53	47.10	0.00



6.2.4 Single flash power plant- Stage II

In the previous sections of this report, three power plant technologies have been introduced and modelled as proposal cycles to develop the San Vicente project for Stage I using the data available from the geothermal wells SV-5A and SV-5B.

The harnessing plan proposed to develop Stage II of the San Vicente project utilising two power plant technologies and four new production wells. The two technologies of power plants that will be modelled are the single flash and the binary cycle. The new wells will be drilled in well pads SV-4 and SV-6. The properties of the reservoir associated with these new wells are assumed to be 256 °C, 1,350 kJ/kg, with a steam fraction of 30%. These assumptions are in the range of the data available from the San Vicente project to date. Moreover, the production curve for these new wells is assumed to be similar to the first wells drilled. Nevertheless, it is known that production curves are developed during the testing well period. In this report, the production curve for the new wells follows Equation (6.2.

$$M_{P.Well} = 37 + 0.0118 * P - 0.00001143 * P\text{^}2 \tag{6.2}$$

Where, P is the separation pressure

Finally, the assumptions defined for the single flash cycle model are presented in Table 6-12 and are based on the main consideration presented in the single flash cycle for Stage I (Section 6.2.2). Figure 6-19 shows the proposed flow diagram of the single flash cycle for developing Stage II of the San Vicente project.

Table 6-12 Assumptions for a single flash cycle Stage II

System	Parameter	Unit	Value
Reservoir	Productive curve new wells	$m_{total} = f_{(P)}$	m = 37 + 0.0118 * P - 0.00001143 *P^2
Well	Enthalpy	KJ/Kg	1350
	Temperature	°C	256
Power plant	Turbine isentropic efficiency	%	82.2
	Atmospheric pressure	kPa	90.85
	Ambient temperature	°C	22.23
	Wet bulb temperature	°C	20.35
	Relative humidity	%	85
	Terminal temperature difference	°C	5
	Condenser pressure	kPa	8
	Temperature of cooling water	°C	25

The P-value in the productive curves is the separation pressure.
Parameter defined for a single flash cycle in Section 6.2.2

The power plant location in Stage II is proposed to be installed near well pad SV-1. Section 6.3 will present the power plant location, production and reinjections wells.

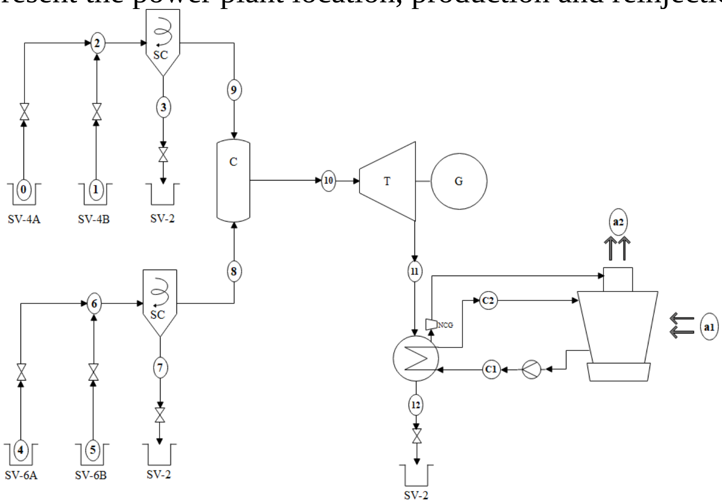


Figure 6-19 Single flash cycle schematic for Stage II

Using EES to identify the maximum power output for this power plant cycle, the separation pressure has been varied in the range that a single flash power plant generally performs, from 600 to 2,000 kPa. The results of this modelling are shown in Figure 6-20, where the maximum gross power generated by this cycle is 22.60 MW at 600 kPa.

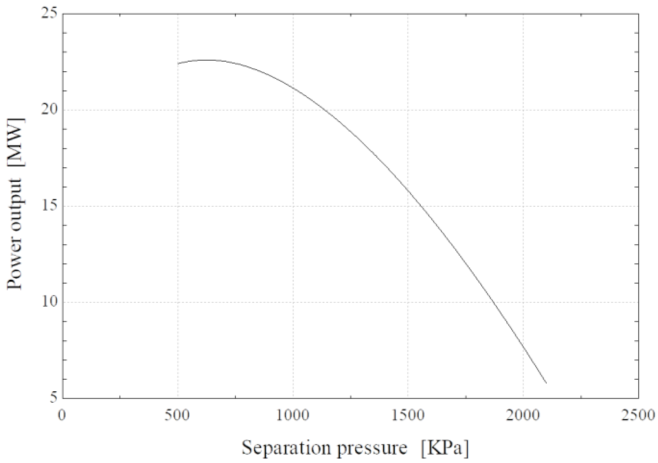


Figure 6-20 Gross power output at different separation pressures of a single flash cycle for Stage II

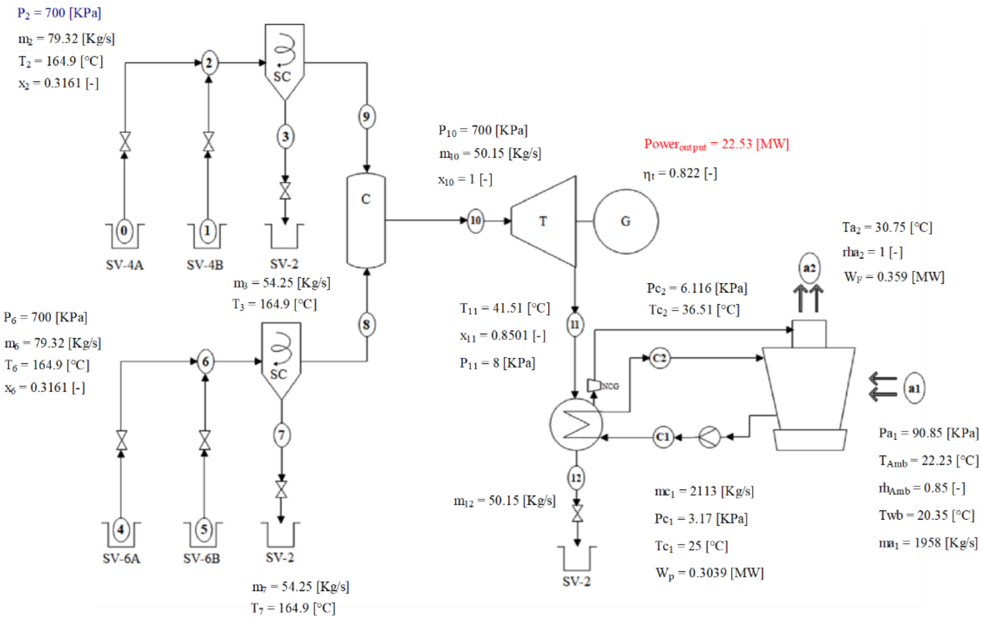
This report proposes keeping the exact value of separation pressure from the single flash model of Stage I to standardise the design and working pressures in the power plant. Therefore, the separation pressure at 700 kPa generates 22.53 MW with an 85 % quality of exhausted steam.

The modelling mass balance analysis and thermodynamic properties using the assumptions presented in Table 6-12Table 6-10 with the separation pressure of 700 kPa, is shown Table 6-13.

The reinjection brine flow rate produced by this cycle is 158.65 kg/s. This amount of brine is proposed to be reinjected in wells located in well pad SV-2. Since the total reinjection capacity of these wells is estimated at 100 kg/s, the operation of the power plant can be affected due to this tight reinjection capacity. Therefore, one more reinjection well needs to be drilled to guarantee the safe and efficient operation of the power plant.

Table 6-13 Parametric tables for a single flash cycle Stage II.

Property	Enthalpy	Mass	Pressure	Entropy	Temperature	Quality
Units	[KJ/Kg]	[Kg/s]	[KPa]	[KJ/Kg*°C]	[°C]	[-]
Point [i]	h[i]	m[i]	P[i]	s[i]	T[i]	x[i]
0	1350.00	39.66	4395.00	3.29	256.00	0.00
1	1350.00	39.66	4395.00	3.29	256.00	0.00
2	1350.00	79.32	700.00	3.48	164.90	0.32
3	697.00	54.25	700.00	1.99	164.90	0.00
4	1350.00	39.66	4395.00	3.29	256.00	0.00
5	1350.00	39.66	4395.00	3.29	256.00	0.00
6	1350.00	79.32	700.00	3.48	164.90	0.32
7	697.00	54.25	700.00	1.99	164.90	0.00
8	2763.00	25.07	700.00	6.71	164.90	1.00
9	2763.00	25.07	700.00	6.71	164.90	1.00
10	2763.00	50.15	700.00	6.71	164.90	1.00
11	2216.00	50.15	8.00	7.08	41.51	0.85
12	173.80	50.15	8.00	0.59	41.51	0.00
C1	104.80	2113.00	3.17	0.37	25.00	0.00
C2	152.90	2082.00	6.12	0.53	36.51	0.00
a1	63.02	1958.00	90.85	5.86	22.23	0.85
a2	112.50	1958.00	90.85	6.03	30.75	1.00



6.2.5 Binary cycle power plant – Stage II

This report is modelling a binary power cycle using the steam and brine produced by the new wells to be drilled in well pads SV-4 and SV-6. The total brine mass flow produced from these wells will be used to preheat the working fluid, and the total steam mass flow will be used to vapourise the working fluid, following the same considerations and assumptions presented in Sub-Section 6.2.3. Figure 6-21 shows the proposed flow diagram of the binary cycle for Stage II to develop the San Vicente project.

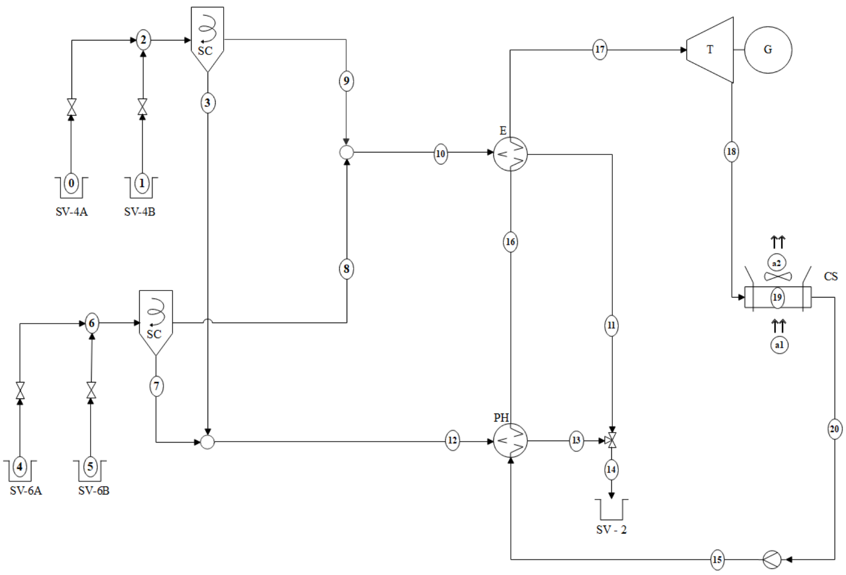


Figure 6-21 Binary cycle schematic Stage II

In order to determine the working separation pressure of the primary cycle, a simulation of well curves has been done, varying the separation pressure values to know the mass flow of steam and brine that can be produced for the new wells. These results help to design the separation pressure for the geothermal cycle and are shown in Figure 6-22

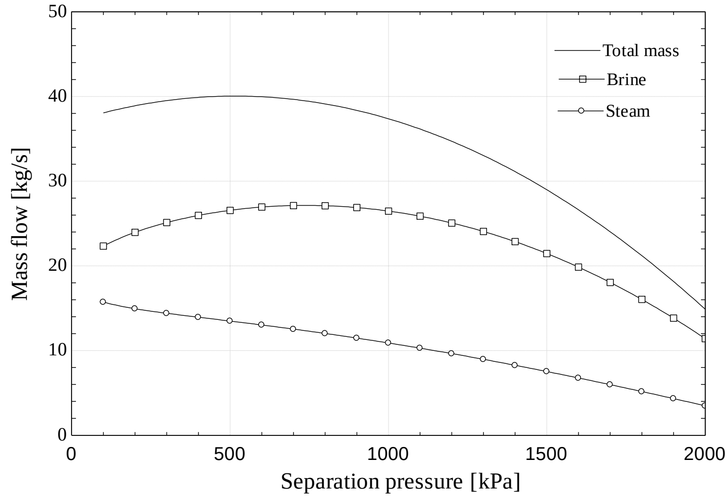


Figure 6-22 Mass flow production curve for the new wells

Since the slope of the steam production curves indicates variations close to 0.5 kg/s of steam for a change of 100 kPa, this report will consider the value of separation pressure where the wells have the maximum brine mass flow. As a result, the most suitable separation pressure for the new wells is at 700kPa. At this pressure, the mass flow of steam and brine are 12.54 kg/s and 27.12 kg/s, respectively.

Using EES to model this power plant cycle by varying the turbine inlet pressure, the turbine gross power output is determined. The assumptions are presented in Table 6-14 and, as mentioned above, are based on the main consideration presented in the binary cycle for Stage I (Sub-Section 6.2.3).

Table 6-14 Assumptions of the binary cycle application Stage II

System	Parameter	Unit	Value
Reservoir	Productive curve new wells	$m_{total} = f_{(P)}$	m = 37 + 0.01178 * P - 0.00001143 * P^2
Well	Enthalpy	KJ/Kg	1350
	Temperature	°C	256
Power plant primary cycle	Separation pressure	KPa	700
	Reinjection temperature	°C	100
Power plant secondary cycle	Working fluid	-	Isopentane
	Turbine isentropic efficiency	%	80.4
	Pump isentropic efficiency	%	75
	Ambient temperature	°C	22.23
	Atmospheric pressure	kPa	90.85
	Relative humidity	%	85
	Wet bulb temperature	°C	20.35
	Pich-point temperature difference (TPP)	°C	5
	Terminal temperature difference (TTD)	°C	5
	Condensing pressure	kPa	180

The gross power output results are shown in Figure 6-23. This report proposes keeping the exact value of separation pressure from the binary cycle of Stage I to standardise the design and working pressures in the power plant. Therefore, the turbine inlet pressure at 2,500 kPa generates 18.93 MW.

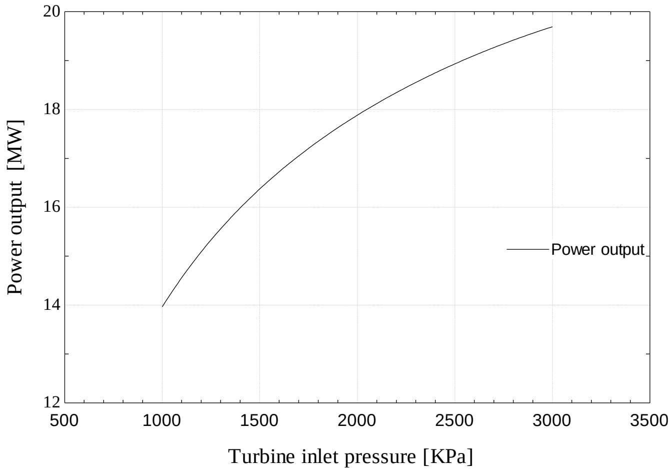


Figure 6-23 Gross power output at different turbine inlet pressure for a binary cycle for Stage II

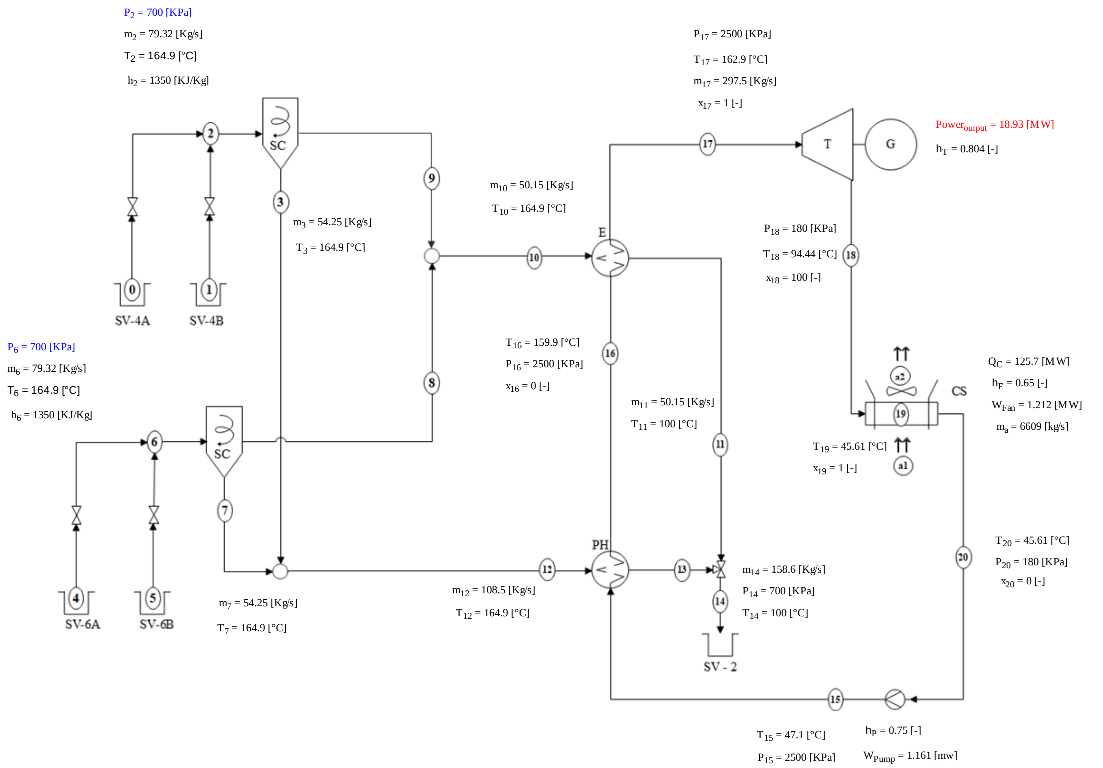
The modelling mass balance analysis and thermodynamic properties using the assumptions presented in Table 6-14Table 6-10 and the turbine inlet pressure at 2,500 kPa are shown in Table 6-15.

The reinjection brine flow rate produced by this cycle is 158.6 kg/s. As discussed in the single flash cycle, this amount of brine is proposed to be reinjected in wells located in well pad SV-2. Since the total reinjection capacity of these wells is estimated at 150 kg/s, the operation of the power plant can be affected due to this tight reinjection capacity. Therefore, one more injection well needs to be drilled to warranty the safe and efficient operation of the power plant.

The reinjection capacity needs one more reinjection well because utilising a binary cycle with an air cooling system and a single flash technology utilising a surface condenser as part of the cooling system allows reinjecting the total mass of the geofluid back to the reservoir.

Table 6-15 Parametric tables for a binary cycle Stage II

Property	Enthalpy	Mass	Pressure	Entropy	Temperature	Quality
Units	[KJ/Kg]	[Kg/s]	[KPa]	[KJ/Kg*°C]	[°C]	[-]
Point [i]	h[i]	m[i]	P[i]	s[i]	T[i]	x[i]
0	1350.00	39.66	4395.00	3.29	256.00	0.00
1	1350.00	39.66	4395.00	3.29	256.00	0.00
2	1350.00	79.32	700.00	3.48	164.90	0.32
3	697.00	54.25	700.00	1.99	164.90	0.00
4	1350.00	39.66	4395.00	3.29	256.00	0.00
5	1350.00	39.66	4395.00	3.29	256.00	0.00
6	1350.00	79.32	700.00	3.48	164.90	0.32
7	697.00	54.25	700.00	1.99	164.90	0.00
8	2763.00	25.07	700.00	6.71	164.90	1.00
9	2763.00	25.07	700.00	6.71	164.90	1.00
10	2763.00	50.15	700.00	6.71	164.90	1.00
11	419.20	50.15	700.00	1.31	100.00	0.00
12	697.00	108.50	700.00	1.99	164.90	0.00
13	419.20	108.50	700.00	1.31	100.00	0.00
14	419.20	158.60	700.00	1.31	100.00	0.00
15	-297.00	297.50	2500.00	-1.53	47.10	0.00
16	49.96	297.50	2500.00	-1.15	159.90	0.00
17	199.40	297.50	2500.00	-0.28	162.90	1.00
18	120.20	297.50	180.00	-0.23	94.44	100.00
19	26.03	297.50	180.00	-0.51	45.61	1.00
20	-302.20	297.50	180.00	-1.54	45.61	0.00



6.2.6 Parasitic loads

Geothermal power plants generally supply their power requirements to cover the parasitic loads and supply the net power to the national electric grid. The parasitic loads include all pumping power requirements within the plant, NCG system, cooling tower fans, and facilities lighting. Moreover, the produced net power is the difference between the generator output and the parasitic loads.

A condensing single flash unit power plant would require a large parasitic load for NCG removal equipment. Additionally, parasitic loads due to fan power requirements are generally greater for air cooling systems than water cooling systems (DiPippo, 2016a). The parasitic loads for a geothermal power plant using a single flash cycle range from 2 to 5% of the generator gross power output. This percentage is lower than the binary cycle parasitic load requirement, which can reach 20% of the gross power output (Chatenay & Jóhannesson, 2014). The parasitic loads for a back pressure unit are mainly associated with the facilities lighting.

The parasitic loads for the San Vicente project are proposed at 1% for a back pressure power plant, 3.5% if the project utilises a single flash power plant and 12.5 % for a binary cycle power plant.

6.2.7 Power plants model summary

This section summarises the modelling results for the power plant technologies evaluated in this report to propose developing the San Vicente project applying the stepwise strategy. The following Table 6-16 shows the power output result for each technology.

Table 6-16 Power output summary for each stage

Power plant technology	Power output in MW	
	Stage I	Stage II
Back pressure cycle	6.42	-
Single flash cycle	12.66	22.53
Binary cycle	10.08	18.93

Proper selection of the geothermal power plants requires the knowledge and understanding of the reservoir, surface, and the social and environmental conditions of the project. The optimal plant selection and design effectively mitigate the design risk and ensure a sustainable power plant operation throughout the project life (Bouche, 2010).

The total installed costs for a geothermal power plant are typically in the range of 2,000 and 5,000 USD/kW. On average, the costs for binary cycle power plants are higher than single flash power plants that utilise higher temperature resources (IRENA, 2019). In this section, a rough evaluation of the possible project scenarios considers the power plant cost at 2,500 USD/kW for a single flash unit and 3,000 USD/kW for a binary unit. Additionally, the back pressure unit cost is considered at the lower value of the power plant cost range, 2,000 USD/kW.

The first approach of the stepwise development scenarios that will be evaluated is presented in Table 6-17.

Table 6-17 Project development scenarios

Scenario	Power plant technology	Power output in MW					
		Phase I	Phase II	Total Gross power	Parasitic loads	Total Net power	Total cost MUSD
Scenario I	Back pressure	6.42	-	6.42	1.0%	6.35	13
Scenario II	Single flash + binary units	12.66	18.93	31.59	3.5% / 12.5%	28.78	88
Scenario III	Binary + single flash units	10.08	22.53	32.61	12.5 % / 3.5%	30.56	87
Scenario IV	Two single flash units	12.66	22.53	35.19	3.5%	33.96	88
Scenario V	Two binary cycle units	10.08	18.93	29.01	12.5%	25.38	87

Table 6-17 shows that developing the project utilising power plant units from one of the last four scenarios required similar investment. This report will develop a financial model in Chapter 7 to estimate the project’s total cost and determine the most feasible strategy for developing the San Vicente project based on these scenarios.

6.3 Gathering system configuration

6.3.1 Gathering system for Stage I

The San Vicente project has six drilling pads with access roads along the geothermal field. For developing Stage I, as has been presented in the power plant modelling, two production wells are ready to be utilised, which are located in well pad SV-5, and two reinjection wells with good permeability are located in the well pad SV-2.

The power plant and the separation stations are proposed to be installed at the same production well pad SV-5. A project layout with the location of the main components required to operate the power plant on Stage I, is presented in Figure 6-24. This stage proposes a project development plan including an electrical substation and the transmission line with the capacity load for the total estimated project capacity. The substation is proposed to be located in the same area where the second power plant is planned to be built.

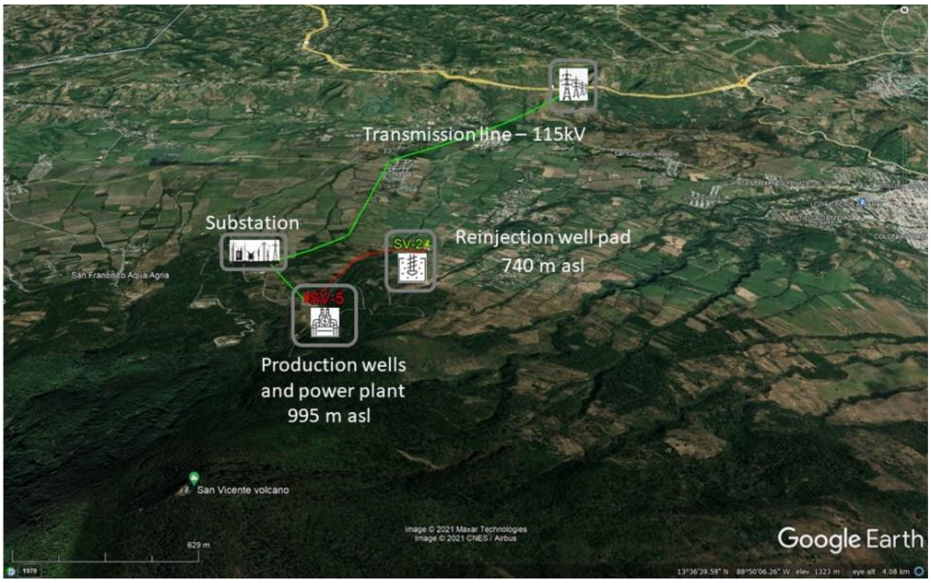


Figure 6-24 Project layout Stage I

Additionally, the separated brine will be reinjected in well pad SV-2, taking advantage of the gravitational potential due to the well pads elevation difference. The length of the reinjection pipeline is approximately 1,600 m, and the elevation profile of the pipeline route from the production well pad SV-5 to the reinjection well pad SV-2 is shown in Figure 6-25.

The pipelines and connection design between the power plant elements must be part of the agreements in the construction contract. The transmission line to connect the power plant to the national grid transmission is described in Sub-Section 6.4.

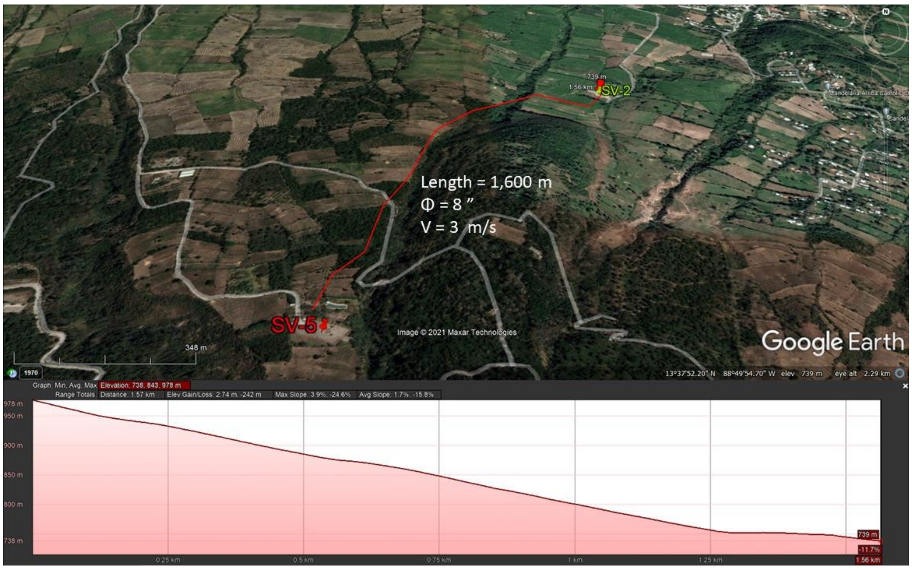


Figure 6-25 Elevation profile and route of the reinjection pipeline from well pad SV-5 to SV-2

A reinjection pipeline with a diameter of 8 in is proposed to be installed. The maximum flow rate of brine that this pipeline will manage is 94 kg/s at a reinjection velocity of 3 m/s when installed in a binary cycle power plant. For a single flash unit, the maximum flow in this pipeline is 87 kg/s at the same velocity.

6.3.2 Gathering system for Stage II

Stage II of the San Vicente project is proposed to be developed utilising the steam from the production well pads SV-4 and SV-6. As presented in the power plant modelling, four new productions wells are required. Two production wells need to be drilled in both well pads SV-4 and SV-6. The project has two reinjection wells with good permeability located in the well pad SV-2. Nevertheless, the power plants cycle modelling determines that it is recommended to drill the third reinjection well in the same well pad to guarantee the efficient performance and operation of the power plant. The proposed power plant location, separation stations, substations, geofluid pipelines routes, and transmission power lines are shown in Figure 6-26Figure 6-24.

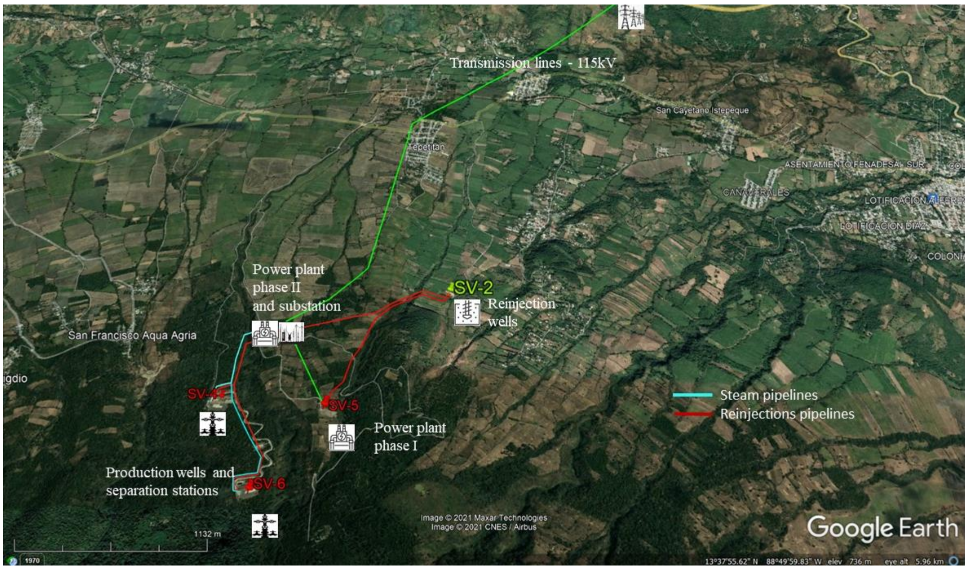


Figure 6-26 Project layout Stage II

The power plant location and the pipeline routes selection must be carefully consider the topography. In mountainous terrain, it is a good practice to conduct a topographical survey before determining the construction site for the power plant and the gathering system.

The power plant is located with respect to the locations of the production and reinjection well pads considering the following parameters aiming to minimise overall project costs: existing infrastructure, utility supply (including access to water), reinjection pumping costs or gravitational potential application, construction of new access roads, equipment orientation, gathering system pipeline costs based on preliminary pipeline sizing, power plant excavation requirements and soil characteristics (Bouche, 2010).

To select the pipelines routes between production wells, the power plants they supply, and the reinjection wells, access for construction and thermal expansion flexibility must be considered. Additionally, when communities are located nearby the geothermal power plant and geothermal facilities, it is important to design the pipeline routes to minimise the visual impact and noise transmission to the surrounding communities (Veizades & Cain, 1991). The gathering systems for the San Vicente project adding Stages I and II are shown in Figure 6-27 and Figure 6-28, with their corresponding pipe sizing tables, Table 6-18 and 6-19, respectively.

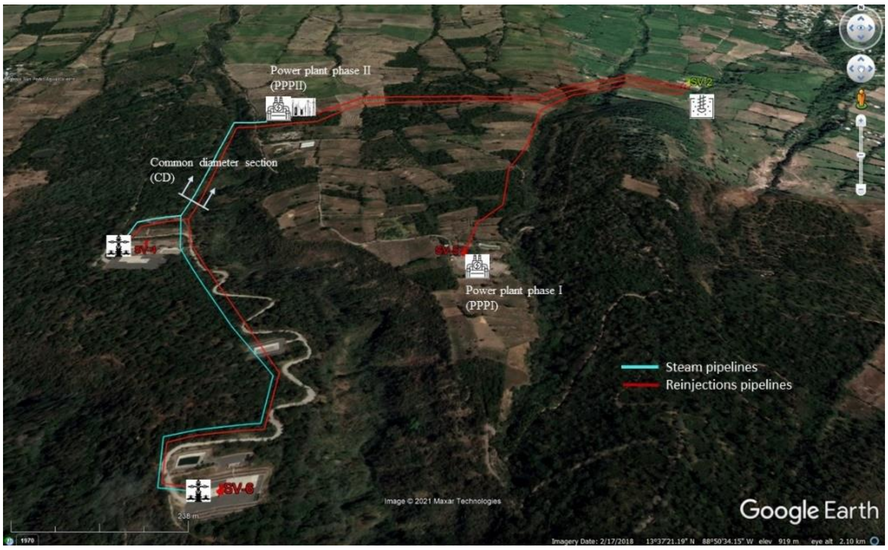


Figure 6-27 Gathering system for Stage I & II utilising single flash units

The steam and brine from the two separation stations on each well production pad are carried out to the power plant and reinjection wells with an individual pipeline from the separation station and joined in a common pipeline before the system is connected to the power plant and before the reinjection wells. The condensed steam from the power plant goes through a reinjection pipeline to the well pad SV-2. The proposed length, diameters, and maximum flowrate capacity of each pipeline to be installed in Stage II utilising a single flash unit are presented in Table 6-18. The diameter for each section is designed with a flowing velocity of 40 m/s for steam and 3 m/s for brine.

Table 6-18 Summary of pipeline sizing installing a single flash power plant

Single Flash power plant							
Type of line	Pipeline Section	Pipe length (m)	Max. mass flow capacity (kg/s)	Flow velocity (m/s)	Pipe diameter (m)	Pipe diameter (in)	Elevation difference (m)
Steam	SV-6 to CD	1,250	29	40	0.508	20	250
	SV-4 to CD	250	29		0.508	20	50
	CD to PPPII	750	58		0.711	28	75
Water	SV-6 to CD	1,250	87	3	0.203	8	250
	SV-4 to CD	250	87		0.203	8	50
	CD to SV-2	2,250	137		0.254	10	160
	PPPII to SV-2	1,500	54		0.152	6	85
	SV-5 to SV-2	1,600	87		0.203	8	255

The gathering system utilising a binary cycle power plant is slightly different from the single flash configuration.

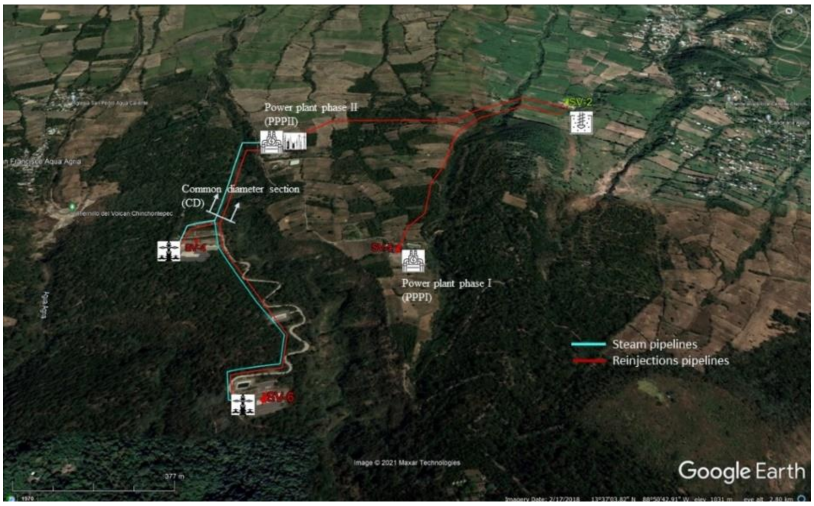


Figure 6-28 Gathering system for Stages I & II utilizing binary cycle units

From the binary cycle power plant, the condensed steam and brine utilised in the primary cycle to transfer energy to the working fluid, goes through a reinjection pipeline to the well pad SV-2. The proposed length, diameters, and maximum flow rate capacity of each pipeline to be installed in Stage II utilising a binary cycle unit are presented in Table 6-19.

Table 6-19 Summary of pipeline sizing installing a binary cycle power plant

Binary cycle power plant							
Type of line	Section	Pipe length (m)	Max. mass flow capacity (kg/s)	Flow velocity (m/s)	Pipe diameter (m)	Pipe diameter (in)	Elevation difference (m)
Steam	SV-6 to CD	1,250	29	40	0.508	20	250
	SV-4 to CD	250	29		0.508	20	50
	CD to PPPII	750	58		0.711	28	75
Water	SV-6 to CD	1,250	87	3	0.203	8	250
	SV-4 to CD	250	87		0.203	8	50
	CD to PPPII	750	137		0.254	10	75
	PPPII to SV-2	1,500	197		0.305	12	85
	SV-5 to SV-2	1,600	94		0.203	8	255

The difference in the total length of pipelines required in the gathering system utilising single flash units and binary cycle power plants in this application is 1,500 m of pipelines. The total length of pipelines to be installed in a single flash configuration is 9,100 m and is the longer pipeline configuration. The binary cycle power plant configuration is 16.5% lower than the single flash arrangements and utilises a pipeline 2 inches in diameter higher for the pipeline section PPPI to SV2, corresponding to the pipeline route from the power plant to the reinjection well pad.

6.4 Transmission lines

The power plant proposed to develop the San Vicente project will supply electric power at 13.8 kV. To connect the power plant to the national transmission grid, 13.8/115 kV step-up transformers are required. The 115 kV transmission line near the project area connects Tecoluca and San Rafael Cedros substations. The national power grid is shown in Figure 6-29. If this power line can carry the additional load from the San Vicente power plant, a switching substation will need to be built at the interconnection point.

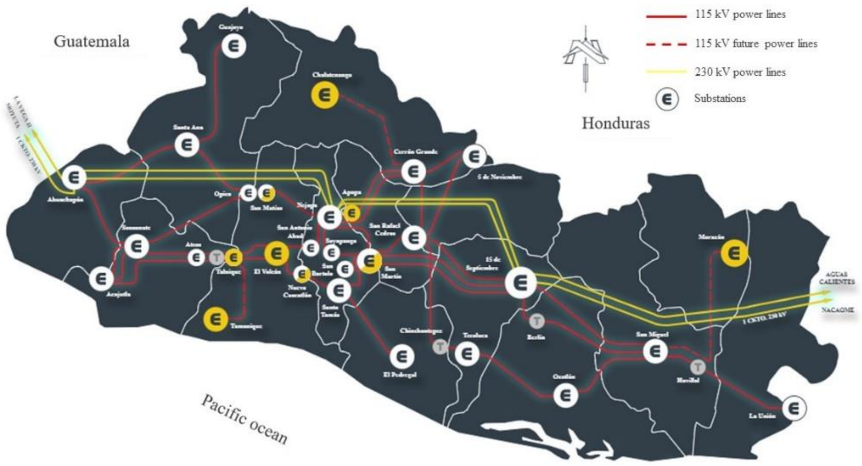


Figure 6-29 El Salvador national grid, modified from (ETESAL, 2021)

The transmission line path for this project is shown in the project layout in Figure 6-24 and Figure 6-26, and the line will be about 4 km long. This report proposed building a dual-circuit power line to accommodate the stepwise development of the power plant.

This Chapter describes the principal components and their main technical characteristics for the San Vicente power plant project's design. Selecting the most suitable geothermal power plant configuration to maximise and manage the reservoir utilisation is a task for designers and project developers. That is why estimating and testing how much steam is available before seeking offers is an important step. Sometimes oversizing and overbuilding the power plant from the field power capacity can carry consequences to the project owner and its investors, creating risk in financing the current and future projects.

The principal elements of geothermal power plants are the wells, pipelines, gathering systems, separators, flashers, turbines, heat exchangers, condensers, cooling towers, and pumps. There are different designs in technologies and configurations for these components. At the same time, the technologies, materials, systems and arrangements to build the entire project present advantages and disadvantages, and the technical specifications are highly driven by the local conditions. For these reasons, selecting the main components depends on each geothermal project sile.

The project owner needs to propose a preliminary design of the power plant that will be completed, specified and finally designed by the manufacturer during the tendering process. Knowing the design, technical specifications of the components, and the power plant configurations will make it easier to estimate the investment cost of the geothermal power plant project and use this information as an input for future financial assessment models.

Chapter 7

Financial assessment model

The financial assessment model of any geothermal project is an essential part of a feasibility study. The main objective of the financial assessment model is to demonstrate that the project will have a financial basis and deliver acceptable returns to the project developer, and at the same time reduce the project risk assessment of the financier. The financier also considers the country risk, type or size of the project, its structure (development phases), location and the level of experience of the project developer in their decision to finance geothermal projects.

A financial model uses inputs in the form of data and assumptions about variables and parameters defining the project and produces outputs from which the project feasibility can be assessed. It is common practice to validate the input data and assumptions used for the model, and this activity is often carried out through a third-party specialist firm (ESMAP, 2021).

7.1 The project capital cost of development and operations cost

The capital investments or expenditure (CAPEX), operating expenses (OPEX), and their distribution over the project life are the inputs parameter to the financial assessment model. The up-front estimation of the investment costs of a new geothermal project is a challenging task, and it is updating as the project has a level of definition. The recommended practice of the Association for the Advancement of Cost Engineering (AACE) provides guidance to estimate the project cost by classifying the costs according to the maturity of the project (AACE International, 2005).

Following the AACE guidance, this report will classify the San Vicente project in an estimating costs Class 4. This classification may be the minimal requirement for feasibility studies in the geothermal industry. Class 4 estimates are typically prepared when the project engineering definition level is in the range of 1% to 15% of the complete project design specifications (basic engineering). Additionally, Class 4 are generally prepared based on limited information and subsequently have a reasonably wide accuracy range. Class 4 estimations are typically used for project screening, feasibility studies, concept evaluation and preliminary budget authorization for looking at funding options. Finally, the accuracy cost of a project in Class 4 ranges from -15% to -30% on the low side and +20% to +50% on the high side. This accuracy percentage highly depends on the technological complexity of the project. A detailed design implies a smaller accuracy range but increases the effort and labour hours to estimate the cost.

The capital expenditure costs should be presented in a list showing the quantities and unit cost in accordance with the project scope. This list includes costs for the main elements of the geothermal facilities such as wells, separation stations, gathering systems, power plants, substations, and transmission lines. Moreover, the cost estimates methods need to be explained (Ingimundarson, 2021).

The operating expenses should, in the same way, be presented. For geothermal projects, the assumptions regarding drilling makeup wells have relevant importance and need to be included in the horizon of the financial assessment model. OPEX includes all the costs that are incurred due to operation and maintenance, such as overhaul costs. The following sections present the cost estimation for the main components of the San Vicente geothermal project that will serve as inputs for the financial assessment models.

7.1.1 Resource exploration costs

The preliminary survey phase usually screens an area of thousands square kilometres to identify a geothermal area of interest. Assuming the development of a 100 MW project, the cost for this activity is estimated to average 770,000.00 USD. Using 2020 USD values as an input for the financial model, the following cost in USD/kW was inflated utilizing the US BLS (U.S. Bureau of Labor Statistics) inflation calculator. The cost for the resource exploration activities can increase depending on the available information, site conditions, the technology used, risk, and possible time delay (Hance, 2005).

The costs of the resources exploration activities carried out in each of the development phases for the San Vicente project are estimated to be an average of 10.20 USD/kW, and the incurred cost will be considered part of the project owner investment. However, national governments, international development institutions or multilateral aid institutions typically finance these activities.

7.1.2 Geothermal well costs

One of the main tasks in the resource exploration phase is to locate the most suitable sites to drill production wells with high fluid temperatures and flow rates. The San Vicente geothermal project, to-date, had drilled seven commercial size geothermal wells, which have helped to identify the size and boundaries of the geothermal reservoir.

The average drilling cost for the wells being drilled in the San Vicente project is 3 MUSD/km. The drilling costs for this project account for eighty percent of the total drilling cost, and this cost is related to the depth and drilling days. Other activities and costs related to drilling activities are mainly access roads and drilling pad construction, well testing, consultancies, reporting, regulatory compliance and permitting, supervision and administration.

Once a geothermal reservoir is discovered, all the project activities consist of drilling production and injection wells, testing well flow rates, running measurement logs and reservoir engineering activities. An example of the design and technical profile of the wells for the San Vicente project was presented in Figure 6-1. The drilling penetration rate for well SV-5A and the percentages of the drilling activities involved in completing one well are shown in Figure 7-1 and Figure 7-2, respectively.

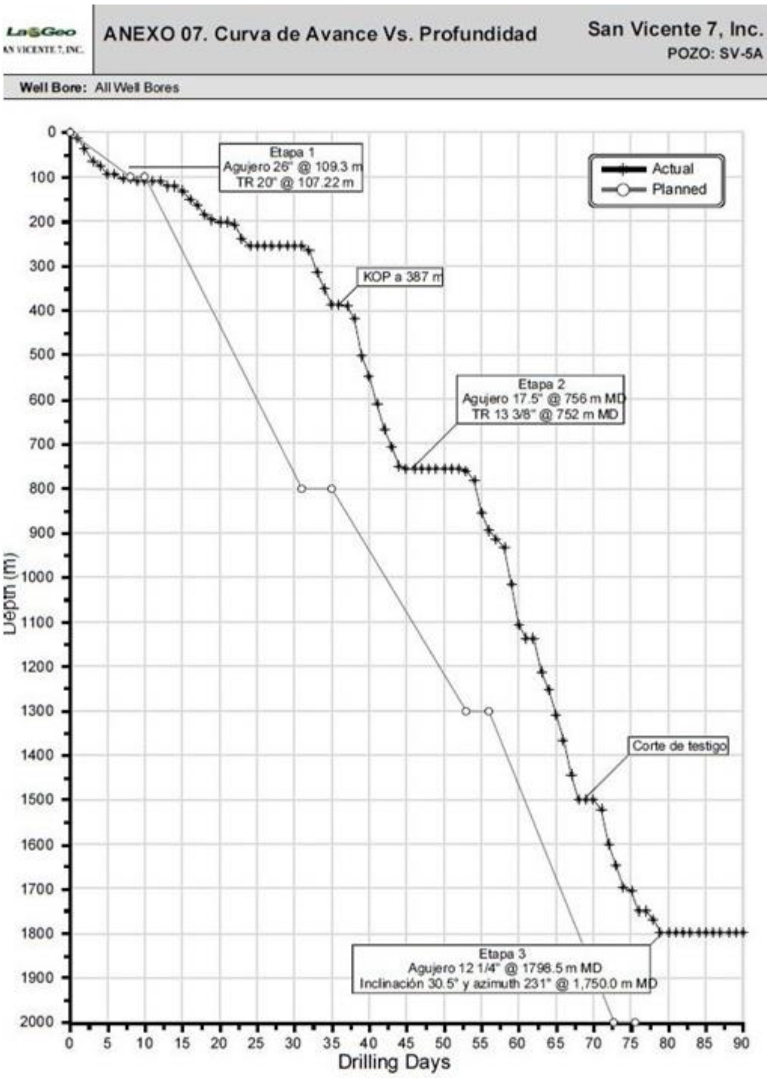
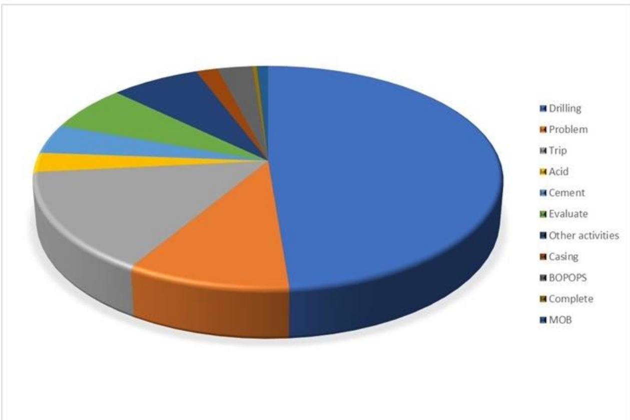


Figure 7-1 Drilling penetration rate of well SV-5A



Operation time	%
Drilling	48.75%
Problem	9.92%
Trip	14.73%
Acid	2.79%
Cement	4.30%
Evaluation	6.66%
Other activities	7.09%
Casing	1.72%
BOP-Operation	2.79%
Complete	0.34%
MOB - Mobilization	0.90%

Figure 7-2 Percentages of operation time by activity of well SV-5A

The total time that it tooks to drill well SV-5A was 2,330 hours. From the total drilling operations, the hours invested in solving problems and rig trips represents close to 25% of the drilling time. For a new development in a green field, as is the case of the San Vicente project, solving problems and trips are considered part of learning effects and contribute to understanding the resource location. The learning effect and the actualisation of the conceptual model increase the drilling success rate for the subsequent phases, and at the same time, the knowledge earned helps improve the well drilling program by reducing the drilling time and costs. The cost-depth correlation model for geothermal cost wells and the learning curve reported by Lukawski et al. show that the 5th geothermal development well drilled in a given field cost in averages no more than 80% of the first well as presented in Figure 7-3. The least learning value will be the assumption cost for the new geothermal wells needed in the field development and construction phases for the San Vicente project.

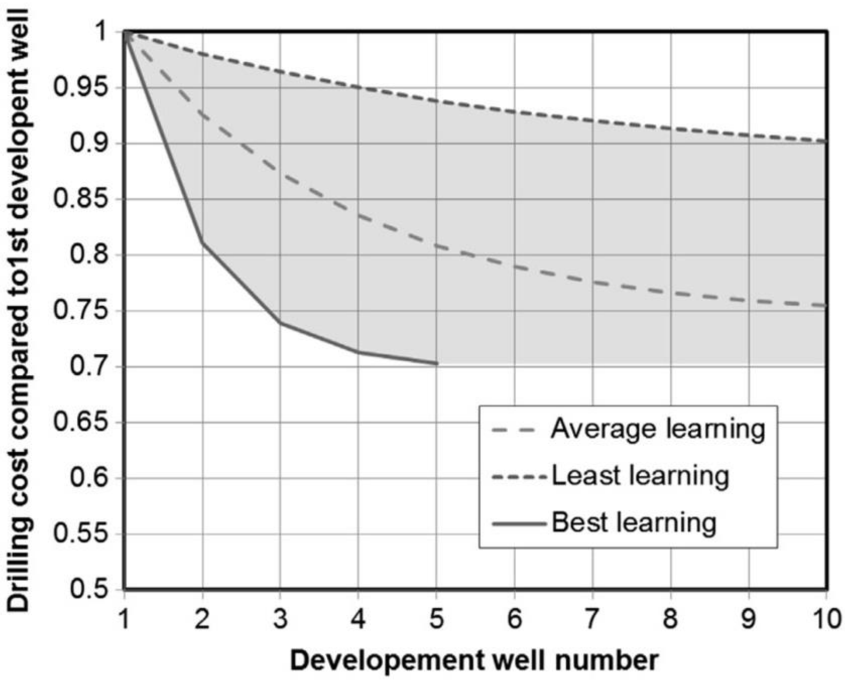


Figure 7-3 Estimated learning curve in geothermal drilling (Lukawski et al., 2014)

7.1.3 Gathering system costs

The main objective of the gathering system is to carry and distribute the geofluids from the production wells to the power plant and the disposal points. The gathering system starts from the wellhead and is compounded by the separation stations, atmospheric silencers, pipelines, and accessories. A geothermal project includes kilometres of pipelines adjusted to the site topography, slope stability, environmental disturbance, material selection, flow rates, type of fluid, pressure, and thermal stress. Different from oil industries, routes of geothermal piping systems are more flexible and open to designer creativity. For this reason, training the designer or contracting a specialist firm with a cost-effective attitude can help improve the project costs (Jung, 1997).

Using 2020 USD values as an input for the financial model, the following cost in USD/m was inflated according to the US BLS inflation. The pipeline installation cost can vary from 690 to 1,380 USD/m, depending on the production and injection well pads distance (Henríquez & Aguirre, 2011). By using this data and applying the three-point estimation method, this report defines the pipeline cost of 1,030 USD/m for the San Vicente project. This cost considers the mechanical and civil work, material, installation, and pipeline supports.

Separators are the significant capital expenditure for well production pads of geothermal projects. The project owner experience and the geothermal developers indicated that a separator cost estimation could be made based on the mass flow rate of the separator station capacity. Estevez reported a cost of 400,000 USD for a separation station of 200 kg/s of capacity (Estévez, 2012). Other costs associated with the separations stations are foundation, piping, valves, diffusers, instrumentations, and engineering, corresponding to 60 % of the total separation station cost (Jung, 1997). This report defines the cost for a separation station using the exponential method shown in Equation (7.1), which applies to estimate the cost of new equipment based on the cost data of similar technology with different capacities, sizes or ratings (Harvey, 2019b).

$$\frac{C_i}{C_o} = \left(\frac{K_i}{K_o}\right)^n \tag{7.1}$$

Where

Ci , Co cost of size i and size o (reference) plants or equipment
Ki , Ko size or rating of units
n scaling exponent, typically ~2/3

Following Equation (7.1), utilising the price reference of 400,000 USD and assuming that the maximum flow rate entering in the San Vicente project separators is 100 kg/s, the cost for one separator is 265,000 USD, and its installation cost 400,000 USD. Therefore, the total cost to build a separation station is estimated at 665,000 USD.

7.1.4 Power plant cost

Power plant design is a complex activity to define the optimal power plant size with the most appropriate technology for the geothermal project aiming to minimise both construction and operation costs for the life project.

A personal conversation with a geothermal power plant manufacturer indicates that a single flash power plant of 25 MW costs 48.6 MUSD, with an adjustment up to +20%. Therefore, the cost of this equipment ranges between 1,944 to 2,333 USD/kW. This report will assume the cost for the single flash power plant at 1,944 USD/kW. The estimated cost for the main components of a binary cycle power plant will be based on an experienced power plant designer (Andal, 2019). Table 7-1 summarises the equations applied to estimate the binary power plant components:

Table 7-1 Equations to estimate the cost for the main components of a binary cycle

Turbine and generator	$C_{T\&G} = W * 400$	(7.2)
Heat exchanger	$C_{HX} = A * 300$	(7.3)
Air-cooled condenser	$C_{AC} = A * 600$	(7.4)
Pumps	$C_P = W * 400$	(7.5)

Where W is the power of the unit in kW, and A is the area of the components in m^2. The cost estimation of these components could be made based on the power plant modelling results. A personal conversation with a geothermal power plant manufacturer indicates that a binary power plant with an air-cooling system can cost 3,500 USD/kW. This cost does not include the geothermal wells and the gathering system cost. This report will assume for a binary cycle power plant the manufacturer cost.

Different procurement strategies on how the project will be designed and constructed may apply to geothermal projects, and the selected method will impact the cost, schedule, quality, and financial aid. Transferring the risk to a well-known construction firm, able to define and control the main aspect of the power plant based on the resource parameters and location of the project, can be considered a best practice in the geothermal industry. By shifting the project risk, the bankability option increases (Harvey, 2019c).

The Construction Management Association of America (CMAA) has prepared a guideline for the project owner to know and compare different delivery methods presenting the pros and cons of keeping the policy of neutral delivery methods. The Design-Bid-Build project delivery method is the most frequently used for construction projects. This method is also known as an Engineering-Procurement-Construction (EPC) or “Turnkey” contract (CMAA, 2012; Harvey, 2019c). For the San Vicente project, this report recommends using an EPC project delivery method.

The market environment for manufacturing geothermal equipment is small. The largest share and the leaders on supply geothermal single flash power plants are Mitsubishi, Toshiba, and Fuji. Ormat and Turboden are the leaders for binary power plants. A “Turnkey” contract with one of these companies reduce the risk of the project.

7.1.5 Power transmission lines

Most geothermal projects are located in remote areas, and the power plant is built near the geothermal reservoir and a transmission facility is not always easy to connect. The cost of the power transmission lines is driven by the distance between the power plant and the nearest transmission facility. The cost is directly affected by the length, but the topography, slope stability, and accessibility of the selected route are also part of its cost. Table 7-2 shows a unit cost per kilometre for a 115 kV double circuit line based on terrain topography, engineering, and construction cost (Estévez, 2012; Hance, 2005).

Table 7-2 Specific costs of power transmission line at 115 kV, modified from (Estévez, 2012)

New transmission line at 115 kV	USD$/km	
Doble circuit , lattice tower	$	997,000.00
Doble circuit , tubular steel pole	$	1,092,000.00

Values inflated according to the US BLS 2020 inflation calculator

Lattice towers are the most commonly used to build a transmission grid across El Salvador. A study comparing lattice towers and tubular poles concluded that the tubular pole reduces the base dimension required to be installed by approximately one-third of the lattice tower space and presents other advantages of utilising this configuration. However, installing a tubular pole requires large capacity cranes, a more skilled workforce, and resources. On the other hand, lattice towers are versatile for installing in cross country areas and do not require heavy machinery, thus contribute to reducing the project environmental footprint (Nishanth & Yadav, 2017). The transmission line for the San Vicente project is described in Section 6.4. This report proposed building a 4 kilometre long double circuit power line installing lattice towers.

7.1.6 Total capital investment cost (CAPEX) and its distribution in the San Vicente geothermal project

The previous section provided the capital expenditure for developing a geothermal project where most of the estimations are based on average cost from different references and experiences from different professionals involved in the industry. The total cost of a geothermal project not only includes the cost for the power plant and transmission power lines, But also the exploration and resource assessment costs, drilling works, field facilities, gathering systems, disposal infrastructures, and other surface installations costs.

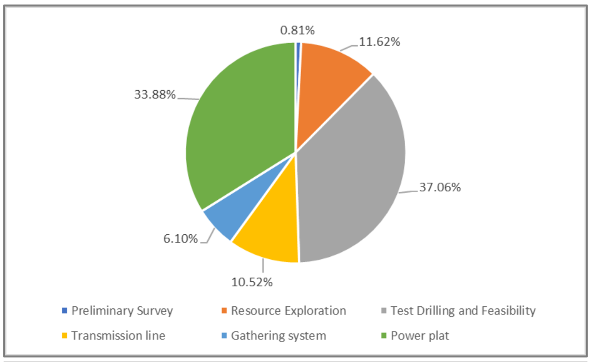
Based on the scenarios presented in Section 6.2.7, Table 7-3 summarises the estimated project cost and shows the breakdown structure of the capital investment of these geothermal development scenarios. The summary and the breakdown structure for the San Vicente project include all the costs associated with the total CAPEX.

In all scenarios, the power plant cost constitutes the higher share of the total cost, followed by the field development, test drilling and feasibility, the gathering system, transmission lines, resource exploration, and preliminary survey. The power plant equipment and construction for single flash and binary units ranges between 44 to 53% of the total investment cost. The phases related to the drilling activities are the field development, the test drilling, and feasibility stages. Adding the cost for these phases of each scenario, the drilling activities range between 31 to 37% of the total investment cost.

Table 7-3 Cost and breakdown structure of development options for the San Vicente project

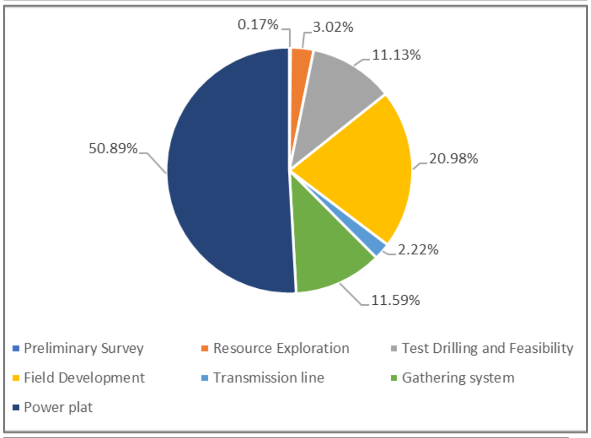
Cost Scenario I - Back pressure unit
Total installed capacity 6.4 MW

Description	MUSD $		%
Preliminary Survey	$	0.31	0.81%
Resource Exploration	$	4.41	11.62%
Test Drilling and Feasibility	$	14.04	37.06%
Transmission line	$	3.99	10.52%
Gathering system	$	2.31	6.10%
Power plat	$	12.84	33.88%
Total	$	37.90	100%
Specific cost MUSD$/MW	**$**	**5.90**	



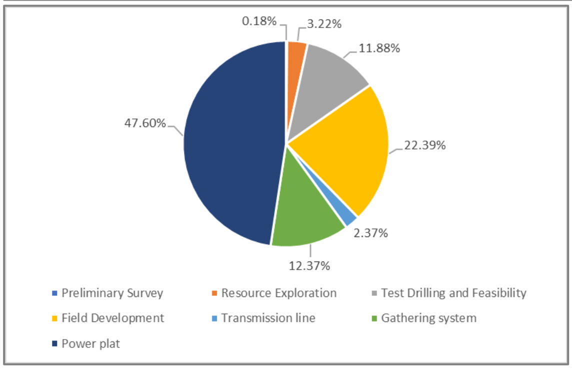
Cost Scenario II – Single flash + binary units
Total installed capacity 31.6 MW

Description	MUSD $		%
Preliminary Survey	$	0.31	0.17%
Resource Exploration	$	5.43	3.02%
Test Drilling and Feasibility	$	20.01	11.13%
Field Development	$	37.73	20.98%
Transmission line	$	3.99	2.22%
Gathering system	$	20.84	11.59%
Power plat	$	91.50	50.89%
Total	$	179.81	100%
Specific cost MUSD$/MW	**$**	**5.69**	



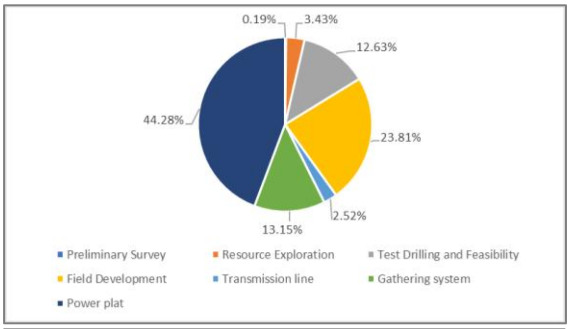
Cost Scenario III – Binary + single flash units
Installed capacity of 32.6 MW

Description	MUSD $		%
Preliminary Survey	$	0.31	0.18%
Resource Exploration	$	5.43	3.22%
Test Drilling and Feasibility	$	20.01	11.88%
Field Development	$	37.73	22.39%
Transmission line	$	3.99	2.37%
Gathering system	$	20.84	12.37%
Power plat	$	80.20	47.60%
Total	$	168.51	100.00%
Specific cost MUSD$/MW	**$**	**5.17**	



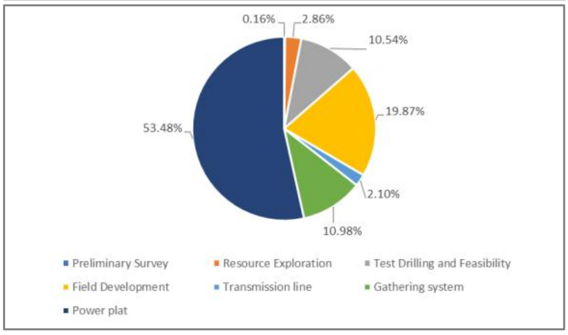
Cost Scenario IV – Two single flash units
Installed capacity of 35.2 MW

Description		MUSD $	%
Preliminary Survey	$	0.31	0.19%
Resource Exploration	$	5.43	3.43%
Test Drilling and Feasibility	$	20.01	12.63%
Field Development	$	37.73	23.81%
Transmission line	$	3.99	2.52%
Gathering system	$	20.84	13.15%
Power plat	$	70.17	44.28%
Total	$	158.48	100%
Specific cost MUSD$/MW	**$**	**4.50**	



Cost Scenario V – Two binary units
Installed capacity of 29 MW

Description		MUSD $	%
Preliminary Survey	$	0.31	0.16%
Resource Exploration	$	5.43	2.86%
Test Drilling and Feasibility	$	20.01	10.54%
Field Development	$	37.73	19.87%
Transmission line	$	3.99	2.10%
Gathering system	$	20.84	10.98%
Power plat	$	101.54	53.48%
Total	$	189.85	100%
Specific cost MUSD$/MW	**$**	**6.54**	



From 2007 through 2021, Figure 7-4 shows the overall cost of geothermal projects by technology and capacity. The specific cost for a geothermal project ranges varies from 2 to 7 MUSD/MW. If the project consists of adding capacity to an existing power plant, the specific cost is weighted in the lower values of the range. On the other hand, the specific cost is higher for new developments. In 2020, the global average specific cost was 4.5 MUSD/MW (IRENA, 2021). The specific cost of development scenarios presented in this report ranges from 4.5 to 6.5 MUSD/MW.

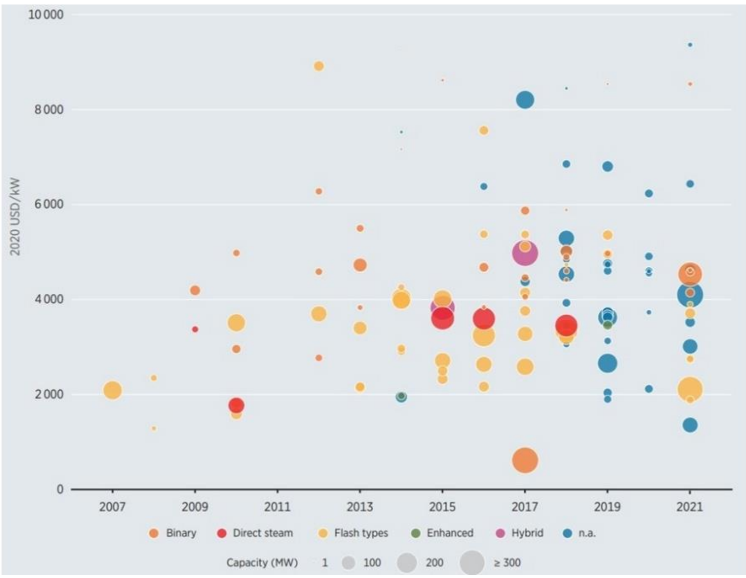


Figure 7-4 Total installed cost for geothermal projects (IRENA, 2021)

7.1.7 Operating expenses costs (OPEX)

Operation expenses cost (OPEX) for a geothermal project can be divided into the OPEX for the steam field and the OPEX of the power plant. These costs correspond to all expenses needed to keep the power plant capacity running as high as possible in order to minimise the cost of energy produced. These costs depend on the location and size of each project. The OPEX of the steam field depends on the fluid chemistry, geology, the quality of the wells, and equipment technology. The OPEX cost for the power plant units is heavily influenced by the chemical composition of the geofluids and the number of operators needed to run the power plant (Estévez, 2012; Gehringer & Loksha, 2012; Hance, 2005).

Typical OPEX estimated costs range from 9 USD/MWh (large units) to 25 USD/MWh (small binary power plants) when make-up wells are not included. When make-up wells are considered, the OPEX cost is estimated as an average worldwide an 19 – 24 USD/MWh (International Energy Agency, 2011a).

Additionally, following the manufacturer instructions for some power plants is recommended to carry out a major overhaul every two years, in the case of the project owner experience. Other power plants carry out major overhauls every four years, assuming that no failures occurred in the meantime. However, a best practice in the industry is to shut down the power plant once a year to explore the internal part of the main equipment with a borescope and identify any failure (Gunnarsson, 2013).

Finally, geothermal power plants provide base-load generation, and their capacity factors can reach 95% (International Energy Agency, 2011a). This report will assume for the San Vicente project 19 USD/MWh as an OPEX cost, a major overhaul for each unit every two years and a power plant capacity factor of 95%.

7.2 Financial model

This report presents a financial feasibility analysis to evaluate the decision to develop a new geothermal power plant project. Using a spreadsheet program on Microsoft Excel, a numerical model is simulated to determine the project's profitability. Using mathematical models for the financial evaluation of projects makes it easier and less time consuming to update the analysis when the model input assumptions change as the project progresses. The numerical model is based on the lecture notes of the course Energy Financial Assessments at Reykjavik University (Jensson, 2019).

A feasibility study evaluates investment costs from the technical, environmental, social, legal, finical, market, political and organizational perspectives. The financial feasibility analysis is often the weighted factor in the decision-making process, as most investments are not developed if they do not generate profit for the project owners.

This report used a financial model to evaluate the scenarios earlier proposed to develop the San Vicente power plant project. The investment cost for each scenario has been determined by engineering and technology selection made in previous chapters and will act as input in the financial models.

The financial model forecast the future condition performance of the project's investment and operations conditions, evaluating the expected value and the risk of an investment. The capital investment decisions are made to contract the construction of buildings and power facilities, supply of equipment, and other activities related to the geothermal project (e.g. geoscientific surveys and permits), which are the most critical decisions the project developers undertake to continue the geothermal project. Some of the reasons why it is important to conduct a financial feasibility study are: Identified reasons not to proceed with the project, enhances the probability of success by addressing and mitigating factors in an early stage of the project, provides quality information for decision-making, helps to secure funding from lending institutions and helps to attract equity investment, among others (Björnsdóttir et al., 2016; Estévez, 2012).

The financial model is constructed to process input assumptions, scenarios, and prerequisites for arranging debt and equity funding. The financial model performs a detailed analysis of the project's cash flow to determine whether the project is sound enough to be pursued. The result from the model can be used to determine relevant criteria to evaluate the project, for example, the rate of return of the project or if the project produces enough cash flow relative to the debt service (Chagaka, 2019).

7.2.1 Model structure

The financial assessment model can be built in different ways. The clearest, effective and easy way to construct is to use an architecture based on several blocks or modules. Each block represents a specific model function, and modules interact between them by receiving and delivering data. This architecture makes the financial model more transparent and allows the user to quickly understand and visualize the model's functionality. The modular architecture is flexible and helps to minimise the risk of errors. In this report, the model developed to evaluate the scenarios proposed for the San Vicente project is based on blocks made in Excel. The blocks are built on separate worksheets with different functions and interconnected in a workbook (Björnsdóttir et al., 2016). The main blocks and their relationships in the modular architecture followed to build the financial model for the San Vicente project are presented in Figure 7-5. The input and assumption block is the only module where users can enter data and collect all the technical and financial assumptions that describe the project.

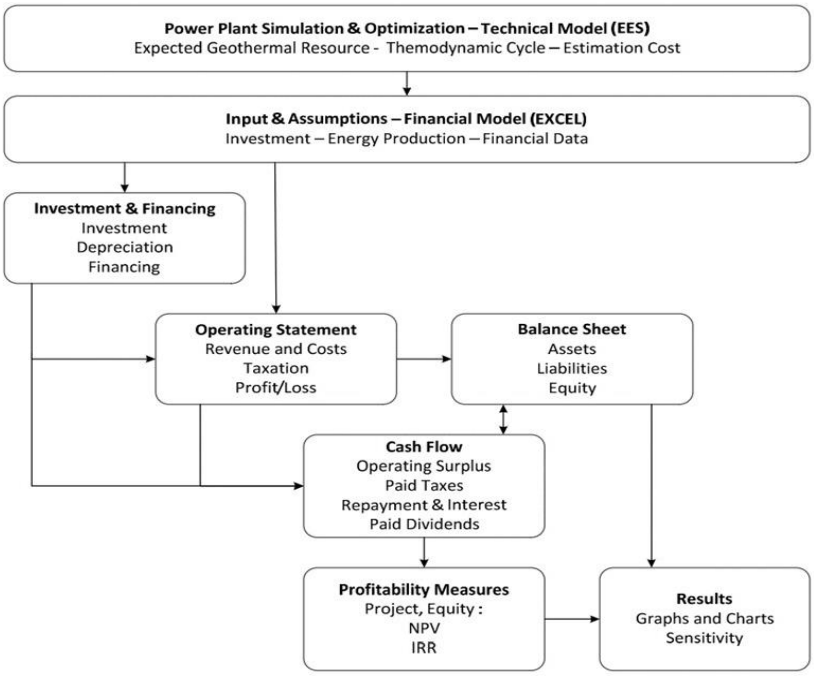


Figure 7-5 Main components of the financial model architecture (Estévez, 2012)

The investment and financial block calculates de financing requirements of the investment project. The financing requirements are based on capital cost and working capital, which is the capital needed to pay short-term debts and continue operations. The calculation of this block determines the booked value and the depreciation of assets, the financing share, and the loan repayment, interest and management fees.

The operation statement shows the performance of the investment project, calculating the operating revenue and expenses over a specific period and can be used for the investors to determine whether their investment will give an acceptable return (Björnsdóttir et al., 2016). In this report, the model performs the operation statement annually. The operation statement includes calculation of EBITDA (Earnings Before Interest, Taxes, Depreciation and Amortization) or operating surplus, which summarises earning before taxes and financial cost. EBIT (Earnings before Interest and Taxes) or operating gain/losses, EBT (Earnings Before Taxes) or profit before taxes and taxable profit. The income taxes are calculated as a percentage of the taxable profit. The last item calculated on the operation statement is the net profit/loss, which results from subtracting the income taxes.

The balance sheet summarises the project's financial position of a project at a given point in time and shows its assets, ownership equity and liabilities. The balance sheet is used as an error-checked instrument to ensure that the financial statement is correctly constructed based on the definition that the assets are equal to the liabilities and owners equity of the project. The assets are organized in order of liquidity, and the first asset will be the cash account. Likewise, the liabilities are arranged in order of payment. Following this arrangement, accounts payable are the first listed while owners equity is at the bottom (Björnsdóttir et al., 2016; Chagaka, 2019).

The cash flow statement shows the actual cash flow of the project and how it is generated and used during each period from operations, investments and financing activities. The cash flow statement helps to analyse the source of funding and the company's ability to meet debt obligations and pay dividends. The cash flow from operating activities consists of adjusting the net profit, adding the non-cash expenses (depreciation and amortization), and the changes in current assets and liabilities. The cash flow from investing activities consists of the purchasing (cash outflow is negative) or selling (cash inflow is positive) of fixed assets. The cash flow from financing activities consists of changes in debt or equity (new loans taken, repayment and new equity). The cash flow statement is considered the time value of money (Björnsdóttir et al., 2016; Chagaka, 2019).

The profitability of the project is calculated from the project's cash flows, and the financial key performance indicators Net Present Value (NPV), Internal Rate of Return (IRR) and the Modified Internal Rate of Return (MIRR) are used as profitability criteria. The profitability measures for evaluating the project and equity are calculated from the free cash flow to equity (FCFE) and the capital investment cash flow (CCF). The free cash flow to equity is the cash flow available to the owners' holders of common equity after operation expenses, interest and loan payments have been paid, and the investments have been made. The capital cash flow is the cash available after the operating expenses have been paid and the investments have been made (Estévez, 2012).

The last block or Excell worksheet is used to report the result of the financial model assessment graphically.

7.2.2 Criteria to evaluate the financial model

Exist numerous methods that can be used to evaluate the financial feasibility of an investment project. The NPV and the IRR are considered more appropriate, commonly accepted and most used methods for investment appraisal of an economic activity. These methods take into account the project's cash flow over a given time and reflect the project's performance in terms of the time value of money (Estévez, 2012).

The Net Present Value (NPV) is the difference between the present value of a future project´s cash flow and the present value of the project's investment cost. The NPV establishes whether or not the investment project is an acceptable investment, given the return required from the investor. In this case, a positive result of NPV for a given project indicates that the project profits are more significant than its costs, and vice versa (Björnsdóttir et al., 2016).

The net present value formula for an investment is presented in Equation (7.6, and the basic decision rule can be generalised as follow:

- (NPV > 0) - Accept the project if the NPV is greater than zero
- (NPV = 0) - The project is indifferent if the NPV is equal to zero
- (NPV < 0) - Reject the project if the NPV is less than zero

$$NPV = \sum_{n=0}^{N} \frac{An}{(1+i)^n} \tag{7.6}$$

Where

An = Net cash flow at the end of period n
i = Interest or discount rate
N = Project's life service

The NPV calculation requires a value for the interest rate or discount rate i, which needs to be determined and is the principal challenge for this method. The discount rate selection is made from the viewpoint of the investor or an entire organisation. The financial cost of capital or the risk-adjusted discount rate can determine the discount rate value. The discount rate is often referred to as Marginal Attractive Rate of Return (MARR), and it represents the rate at which investors can alternatively invest money (Björnsdóttir et al., 2016; Estévez, 2012).

The Internal Rate of Return (IRR) is defined as the compound rate of return i^*that makes the NPV equal to zero, calculated following Equation (7.7.

$$NPV = \sum_{n=0}^{N} \frac{An}{(1+i^*)^n} = 0 \tag{7.7}$$

Investors use their investment policy to decide whether a project is feasible or not. Based on the investor's Marginal Attractive Rate of Return, the general investment decision rule is:

- (IRR > MARR0) - Accept the project if the IRR is greater than the MARR
- (IRR = MARR) - The project is indifferent if the IRR is equal to the MARR
- (IRR < MARR) - Reject the project if the IRR is less than MARR

The IRR method offers a number that summarises the performance of the project. This number does not depend on the interest rate of the financial cost of the capital (Björnsdóttir et al., 2016; Estévez, 2012).

NPV and IRR methods have been criticised for the lack of robustness on the investment decision. These two methods can rank a project differently, and both assume that reinvestment at the same IRR is always possible. The Modified Internal Rate of Return (MIRR) or External Rate of Return is a method that avoids the lack of robustness of NPV and IRR, by assuming that all cash flows are invested at a different rate. The MIRR is calculated by discounting the investment cash outflows committed to the present at an interest rate representing the investment risk. Then, using a predetermined reinvestment rate, compound the cash inflows forward to a time horizon, representing future opportunities with risk equivalent to the investment risk. Finally, calculate the MIRR that makes the future value of cash inflows equal to the present value of outflows with an NPV equal to zero (Björnsdóttir et al., 2016; Chagaka, 2019).

The formula to calculate the MIRR is presented in Equation (7.8, and the basic decision rule is as follow (Chagaka, 2019):

- Accept the project if the MIRR is greater than the cost of capital and the investment is expected to return more than required
- The project is indifferent if the MIRR is equal to the cost of capital and the investment return what is required
- Reject the project if the IRR is less than the cost of capital and the investment is expected to return less than required. The project's return is not proportional to the level project's risk.

$$\sum_{n=1}^{N} \frac{An\,(1+k)^{N-n}}{(1+MIRR)^{N}} - PV(I_0) = 0 \qquad (7.8)$$

Where

An = Cash inflows at the end of period n to calculate the terminal value
k = Reinvestment rate
$PV(I_0)$ = Present Value of investment cash flows
N = Project's life

Financial ratios are used to analyse financial statements, giving a clear panorama of the project's financial conditions and performance successes. At the same time can be used to compare two projects within the same industry. The financial ratios can be divided into five categories: Liquidity, asset management, profitability, market tren and debt management ratios (Björnsdóttir et al., 2016). This report will analyse the debt service coverage and liquidity current ratios.

The liquidity ratios are used to determine if the project is able to pay off its short-term debts. The ratios show the relationship between the project's cash and other assets to its current liabilities. The liquidity current ratio shows the relationship between liquid assets and payment commitments showing which current assets cover current liabilities. The formula is presented in Equation (7.9 (Björnsdóttir et al., 2016).

$$Current\ ratio = \frac{Current\ assets}{Current\ liabilities} \qquad (7.9)$$

Debt ratios are used to determine how the project uses the debt financing and if it can meet debt obligations. Lenders use the debt service coverage ratio to guarantee that the project will have enough funds to pay the loan. This ratio compares the cash flow available for debt service (interest and principal loan payments) to the debt service for the same period. The formula for this ratio is presented in Equation (7.10(Björnsdóttir et al., 2016).

$$Debt\ service\ coverage\ ratio = \frac{Cash\ flow\ after\ tax}{Debt\ service} \qquad (7.10)$$

7.2.3 Model inputs and assumptions

Five scenarios are proposed to develop the San Vicente power plant project. These scenarios are described in Table 7-3. The power output and the investment cost for each scenario are used as input for the financial model. The investment costs include the preliminary surveys, resource exploration, test drilling and feasibility, field development, transmission line, gathering system and the power plant contract. The input assumptions used for the financial model are presented in Table 7-4.

Table 7-4 Financial models' input assumptions

Input	Value	Unit	Description
Planning horizont	30	years	All scenarios
Power plant capacity factor	95	%	All scenarios
Parasitic load	1 / 3.5 / 12.5	%	BP /SF / BC (Units)
Electricity price	90	USD / MWh	All scenarios
Expected growth	5	%	Expected to growth yearly
O&M cost	19	USD / MWh	Include the power plat and steam field
Depreciation	5 / 20 / 20	%	Buildings / machinery / others
Corporate tax	30	%	All scenarios
Structure financing	30 / 70	%	Equity / Debt share
MARR for project capital cost	12	%	All scenarios
MARR for equity	18	%	All scenarios
Interest loan	3.3	%	Annually
Repayment period	25	years	Start at the first production year
Grace period	5	years	All scenarios
Level of commitment	0.5	%	All scenarios
Dividend	30	%	All scenarios

The electricity price is assumed to start whit a value of 90 USD/MWh due to a new market player generating electricity utilising an LNG power plant. At the same time, it is assumed to grow at the annual rate of 5%

The corporate taxes in El Salvador for a one-year operation has been 30% during the last ten years (Trading Economics, 2021a). The depreciation is calculated using the straight-line method, and the annual depreciation rate for the major groups is 5% for buildings, 20% for equipment (Worldwide Tax Summaries, 2021), and 20% for others.

Besides equity, geothermal projects can be financed whit loans and grants (Björnsdóttir et al., 2016). The San Vicente power plant project, as a first-time project, assumes 30% equity and 70% debt share (Estévez, 2012). The financial term is based on the lending rates and fees for blend credits offered by the Worl Bank (WBG, 2021b).

The project owner defines the discount rate, known as MARR, for geothermal project investment. The MARR can be defined between the range of 5 to 25% depending on the risk of the project. Ormat, one of the geothermal development companies in the market, uses a discount rate between 12-18% for a feasible project in developing countries like El Salvador (Estévez, 2012). The MARR for the cost of capital will be assumed at the same interest rate from a lending institution in El Salvador, which range between 12-14% (Trading Economics, 2021b). This report assumes the MARR for equity at 18% and the MARR for the capital cost at 12%.

Nowadays, green bonds are available to finance renewable energy projects. Geothermal projects are eligible for green bonds investment. Iceland, Kenya and Indonesia have developed some of their geothermal projects through green bonds. At the same time, multilateral financial institutions are providing funds to geothermal projects and have also been raising capital through green bonds (Garabetian & Dumas, 2021).

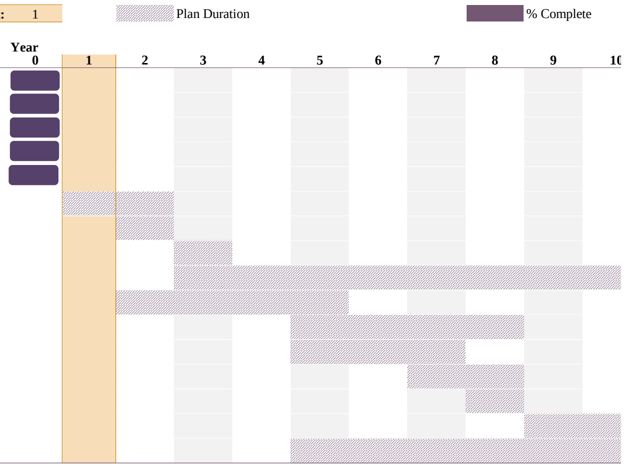
7.3 Project execution plan and schedule

The scope of the project execution plan and schedule is to end with the operation of the power plant. The project execution plan should be developed under the direction and agreement of the owner on project objectives. The milestones included in the schedule are significant events to identify major project segments and are essential cost and technical control points in the project execution (Larson & Gray, 2018b). Figure 7-6 shows the principal segments for the San Vicente power plant project and the cumulative curve cost based on the proposed scenario II to develop the project.

San Vicente Power Plant Project Schedule

Period Highlight: 1

ACTIVITY	PLAN START	PLAN DURATION	PERCENT COMPLETE
Preliminay survey	0	1	100%
Resource exploration	0	1	100%
Test drilling and feasibility	0	1	100%
Project review, planning and design	0	1	100%
Field development	0	1	100%
Construction Unit 1	1	2	0%
Comissioning, training and operations star-up	2	1	0%
Unit 1 - Opeation and maintenance	3	1	0%
Reservoir evaluation	3	10	0%
Test drilling ans feasibility	2	4	0%
Cosntruction - Unit2	5	4	0%
Gathering systems	5	3	0%
Power plant	7	2	0%
Commission, training and opeartion start-up	8	1	0%
Unit 2 - Opeation and maintenance	9	4	0%
Reservoir evalaution	5	8	0%



Year		Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9	
Cumulative Cost MUSD	Scenario II		$ 34.63	$ 58.63	$ 79.24	$ 90.56	$ 97.25	$ 105.59	$ 133.69	$ 166.63	$ 179.81	Come opera

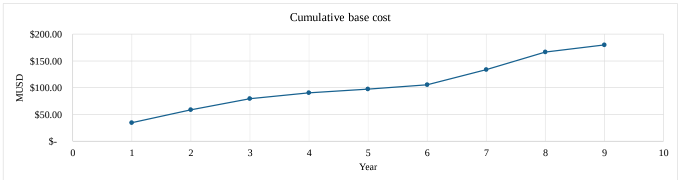


Figure 7-6 The San Vicente project execution plan and schedule

The project is planned and scheduled as has been described in Section 5.4. Years 1 and 2 is the construction time for Stage I. Years 3 and 4 are part of the field development activities for Stage II. The power plant construction for Stage II starts in year 7, after the steam available for the second unit has been confirmed and is scheduled for 2 years. Nonetheless, the construction of the gathering system that is considered part of the construction of the power plant starts in year 5.

In addition, the schedule has been structured using the relationship finish to finish between segments. This structure allows the project owner to allocate capital when it is required to execute the activities yearly schedule. This arrangement helps to distribute the loan's commitment cost and interest payments along the project's construction period due to the financial needs with debt. The cumulative curve cost shows how the capital cost is placed into the project, and the distribution is shown in Figure 7-7. This distribution considered the contract payment condition for each activity, such as 30-50-20% of the power plant EPC contract.

		Year	0 & 1	2	3	4	5	6	7	8	9
Stage	Activity	Cost / year (MUSD)	$ 34.63	$ 24.00	$ 20.61	$ 11.32	$ 6.69	$ 8.34	$ 28.10	$ 32.94	$ 13.18
		Activity cost (MUSD)									
I	Preliminary Survey	$ 0.31	$ 0.31	-							
	Resource Exploration	$ 5.43	$ 5.43	-							
	Test Drilling and Feasibility	$ 20.01	$ 20.01	-							
II	Field Development	$ 37.73		$ 7.55	$ 15.09	$ 11.32	$ 3.77				
I	Transmission line	$ 3.99	$ 1.20	$ 2.39	$ 0.40						
I & II	Gathering system	$ 20.84	$ -	$ 1.25			$ 2.92	$ 8.34	$ 8.34		
I & II	Power plant	$ 91.50	$ 7.69	$ 12.81	$ 5.12				$ 19.76	$ 32.94	$ 13.18
Cumulative cost			**$ 34.63**	**$ 58.63**	**$ 79.24**	**$ 90.56**	**$ 97.25**	**$ 105.59**	**$ 133.69**	**$ 166.63**	**$ 179.81**

Figure 7-7 Project yearly capital distribution for scenario II

Finally, together with the cumulative cost curve, the execution plan and schedule will be used to compare the planned schedule and cost to measure the project performance during the construction phase.

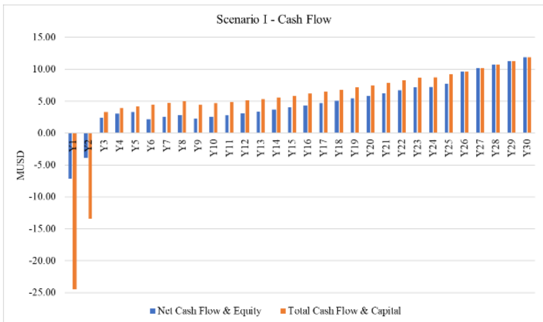
7.4 Financial model results

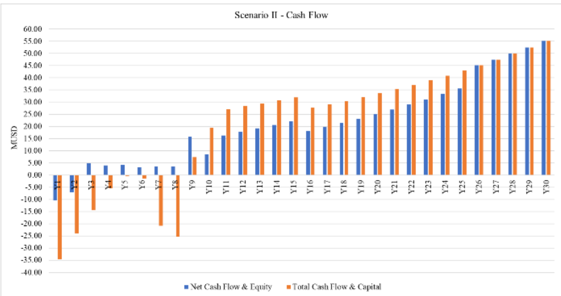
The financial model results for the scenarios proposed to develop the San Vicente power plant project summarise and present a compact overview of the project to help decide whether the project is profitable.

7.4.1 Chas flow

The cash flow of the investment project is presented in Figure 7-8 and shows the cash flow for the equity (FCFE) and capital (CCF).

Scenario	Power plant technology
Scenario I	Back pressure
Scenario II	Single flash + binary units
Scenario III	Binary + single flash units
Scenario IV	Two single flash units
Scenario V	Two binary cycle units





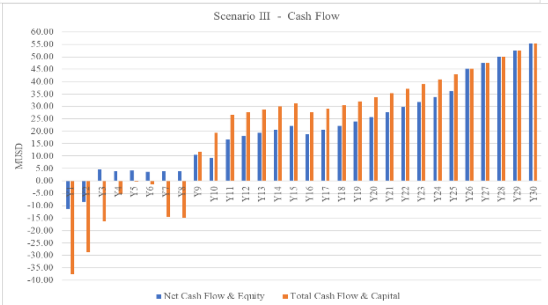


Figure 7-8 Project cash flows for all scenarios

An outflow of cash is seen during eight years of the total project due to capital expenditure associated with the field development and construction stage. The first two years correspond to the construction time of the power plant, its gathering system and the transmission line for the project in Stage I. The project starts to generate cash flows as it starts its commercial operation, with its first unit, in year Y3. At the same time, the development activities for Stage II starts in year Y2 and ends in Y8 with the commission of the second power unit. This second unit starts to generate cash flows as it starts its commercial operation in year Y9.

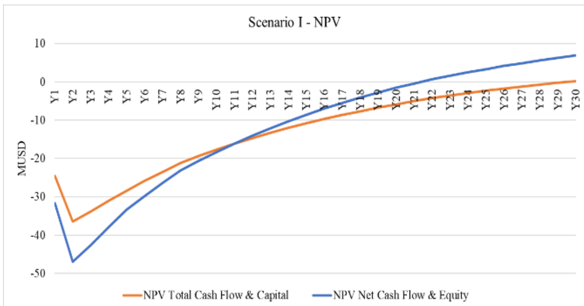
The model assumes that the interest payment is tax-deductible, which can be seen as cash flow variation. The equity cash flows indicate the impact of changes in debt levels. Moreover, after the loan has been paid, the equity cash flow is equal to the capital cash flow. All the scenarios perform similarly; the main difference is the capital expenditure for the technologies selected.

7.4.2 Accumulated NPV

The accumulated NPV of the investment project during the construction and operation phase and planned horizon used for the financial model is shown in Figure 7-9. The accumulated NPV is the first approach to estimate the project's risk. Additionally, when projects are compared, the NPV illustrates which project will reach first a positive NPV, meaning that the project that has reached a positive NPV has the lowest risk.

As seen in Figure 7-9, the NPV for equity and capital are positive over the planning horizon for four of the scenarios proposed to develop the San Vicente project. Scenario IV is the lowest project at risk because it is the first that will reach a positive NPV cash flow. Moreover, scenario V is the riskier project due to being the latest that will reach a positive NPV value at the planned horizon.

Scenario	Power plant technology
Scenario I	Back pressure
Scenario II	Single flash + binary units
Scenario III	Binary + single flash units
Scenario IV	Two single flash units
Scenario V	Two binary cycle units



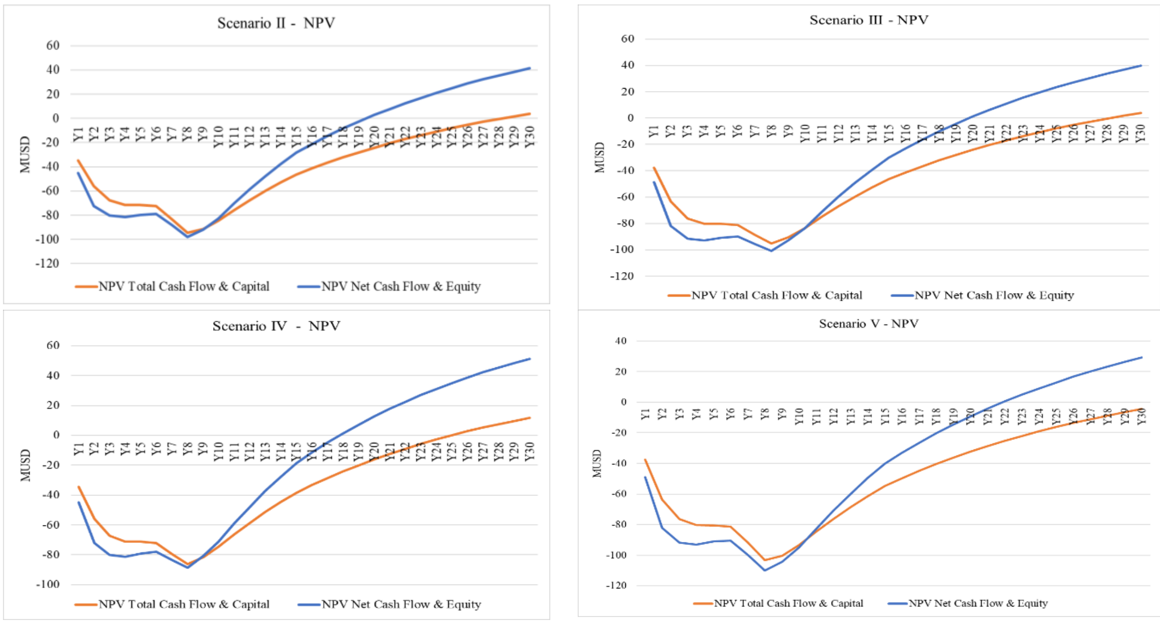


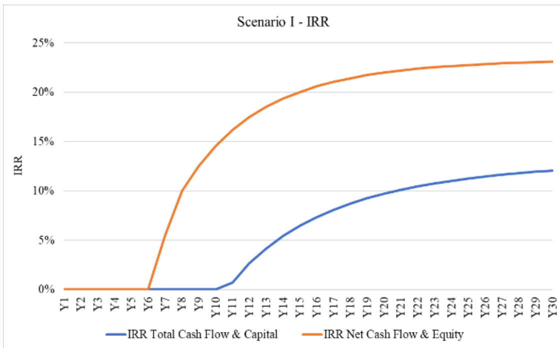
Figure 7-9 Accumulated NPVs for all scenarios

Analysing the accumulated NPV for the proposed scenarios to develop the San Vicente project, Figure 7-9 shows an increase of NPV values after the commercial operation of the units begins. After the first unit is in operation, for scenarios II to V, a steady performance is observed until year Y7, when the capital expenditure for the second unit is done. Furthermore, the NPV values increase sharply once the two units are in commercial operation at year Y9. This sharp increase in the scenario I start at the beginning of year Y3. The proposed scenarios pay the loan, but the return requirements area meet at different periods. Additionally, all the scenarios are economically feasible to undertake for both lenders and project owners. In addition to this, utilising a combination of flash units and binary cycle technologies as proposed in scenarios III and IV seems to be an option to develop the project. Utilising only the binary cycle units requires more capital expenditure and seems not worth pursuing. However, the financial project's performance is similar to other technologies, becoming an option to develop the San Vicente project, and the decision to take this option needs to take into account other projects' advantages like reducing environmental impacts by reinjecting theoretically 100% of the geofluids back to the reservoir.

7.4.3 Internal rate of return

The project's IRR has a particular interest to the investors and is compared with their MARR. It is important to mention that equity to investors faces the risk of not being paid. For that reason, this report assumes a higher MARR for equity (18%) than the MARR assumed for capital (12%). The calculated IRR of capital and equity for the scenarios proposed to develop the San Vicente project are presented in Figure 7-10. The IRR increases rapidly at year Y6 of each scenario until it stabilises and, in the end, remains the same over the years of the project planned horizon.

Scenario	Power plant technology
Scenario I	Back pressure
Scenario II	Single flash + binary units
Scenario III	Binary + single flash units
Scenario IV	Two single flash units
Scenario V	Two binary cycle units



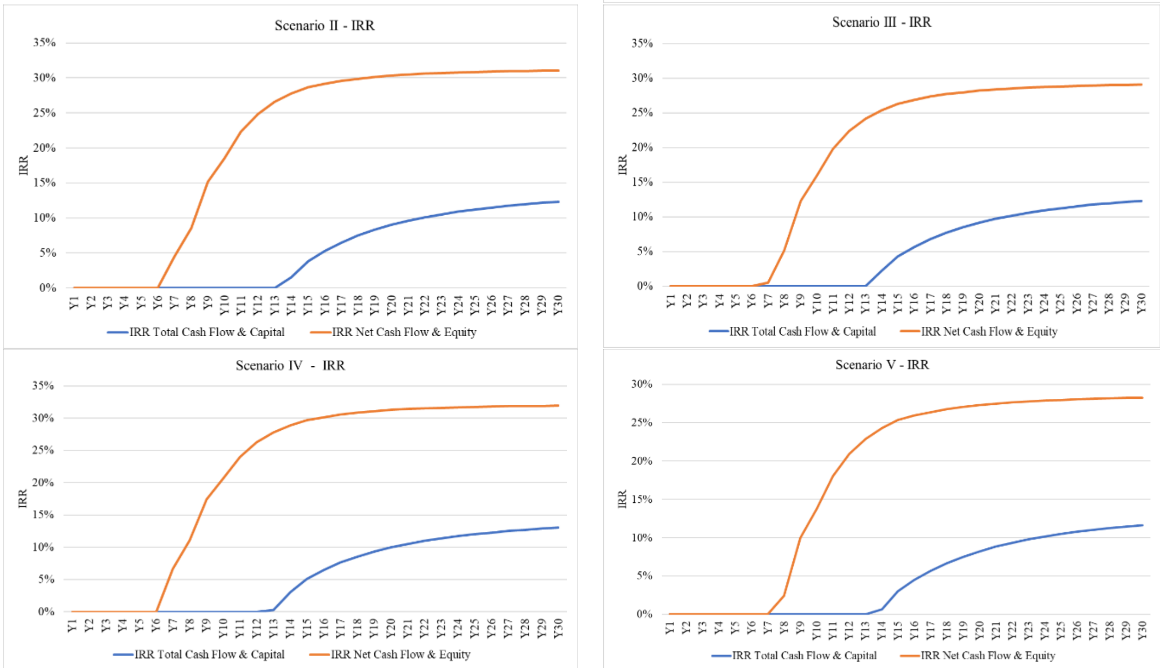


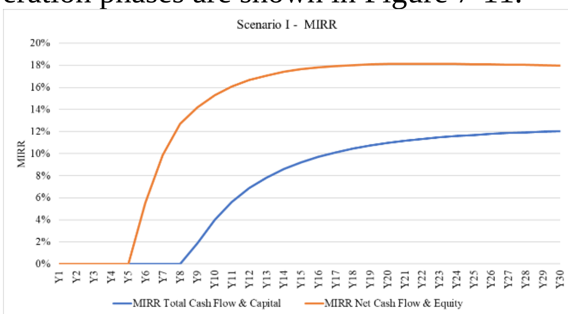
Figure 7-10 IRRs for all scenarios

Analysing the IRR for each scenario, Figure 7-10 shows how the IRR increases and reaches the MARR for capital investment, which s 12%. The planned horizon can be reduced by no more than five years, and the project scenarios are reaching the MARR for capital. Scenario IV is the only one with an IRR of 13%, confirming that it is the scenario with lower risk as discussed for the accumulated NPV. Additionally, the IRR of equity reaches the 18% of MARR in a shorter time than the IRR of equity. Finally, the equity and capital performance IRR proves that the investment is feasible for both the project owner and the lenders.

7.4.4 Modified internal rate of return

The MIRR of the capital and equity for the scenarios proposed to develop the San Vicente project during its construction and operation phases are shown in Figure 7-11.

Scenario	Power plant technology
Scenario I	Back pressure
Scenario II	Single flash + binary units
Scenario III	Binary + single flash units
Scenario IV	Two single flash units
Scenario V	Two binary cycle units



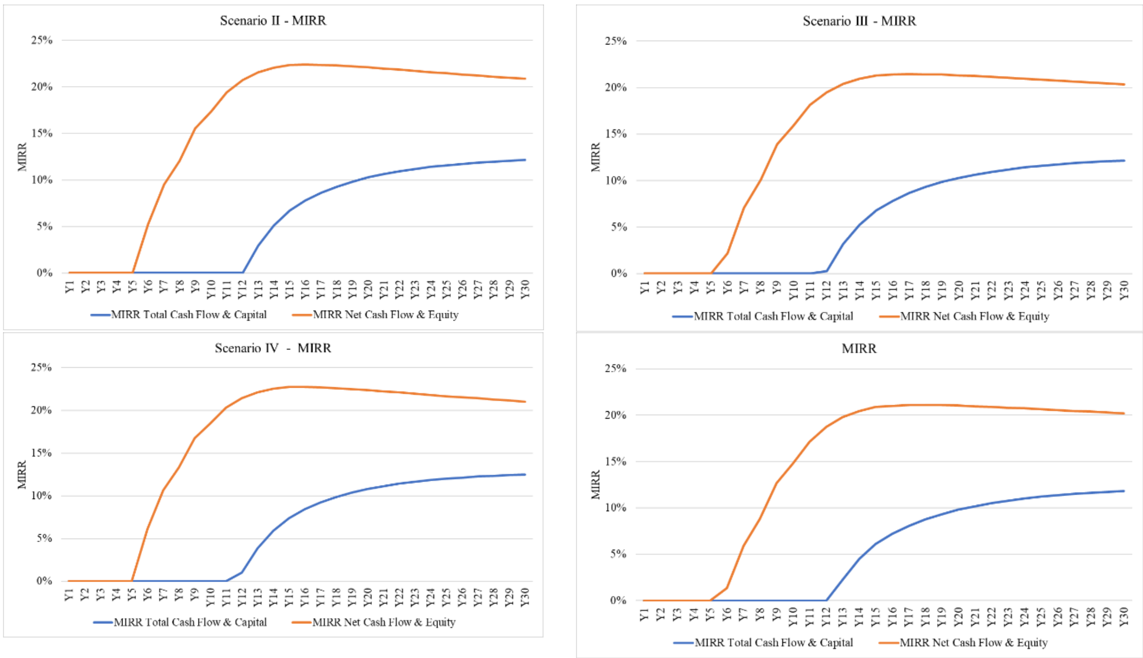


Figure 7-11 MIRRs for all scenarios

Similar to the IRR analysis, the MIRR is compared with an expected rate of return representing future opportunities with risk equivalent to the investment risk. The rate of return assumed in this report are 12% for capital and 16% for equity. All scenarios perform to reach the 12% for capital at the end of the planned horizon. Moreover, the MIRR at the end of the planned horizon for equity is higher than 16% in all scenarios. Finally, following the decision rule, the project returns what is expected from the capital investment and more than the equity performance requires.

7.4.5 Financial ratios

The financial ratios for the proposed scenarios to develop the San Vicente project are shown in Figure 7-12. The debt service coverage ratio confirms the capacity of the project to generate enough cash flow to pay its debts. The liquidity current ratio raises throughout the planned horizon, indicating that the project can pay its short-term debts by utilising its current assets to cover the current liabilities.

Scenario	Power plant technology
Scenario I	Back pressure
Scenario II	Single flash + binary units
Scenario III	Binary + single flash units
Scenario IV	Two single flash units
Scenario V	Two binary cycle units

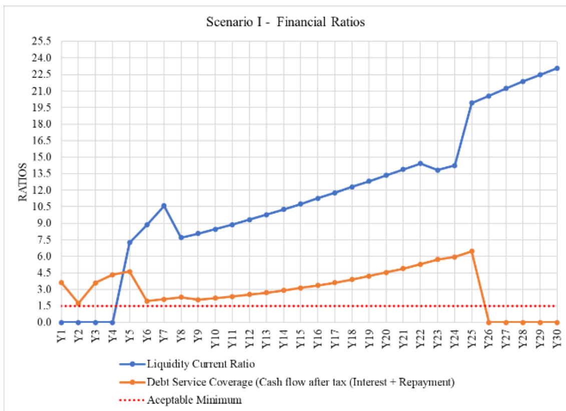


Figure 7-12 Financial ratios for all scenarios

The minimum debt service coverage ratio requirement for the San Vicente project is set as 1.5 and is in the standards levels for power plant projects (Chagaka, 2019). For all scenarios, the project generates enough cash flow during the first 5 years due to the grace period. The ratio is at the limit from year Y6 to year Y8 in scenarios I to IV. Scenario V has the lowest value of 1.3 in these years, meaning that the project might face some problems covering its debts, but this performance is not a risk condition to not decided to undertake scenario V to develop the project. From year Y9, whit the second unit in operation, the ratio indicates that the project has enough capacity to generate cash flow to cover its debts.

The decline of the liquidity current ratio in year Y5 is mainly due to the end of the grace period. In year Y15 another variation is observed when the depreciation for equipment and others has finished. Finally, the liquidity current ratio increases when the debt payment is completed in year Y25.

7.4.6 Sensitivity analysis

The term risk in a geothermal project can be associated with potential losses. The financial model results are based on inputs parameters and assumptions for a single scenario. Nonetheless, the results from the model do not provide the investor with how changes in the input parameters might affect the outcomes of the model. Therefore, risk analysis can analyse the variability in a financial assessment model (Björnsdóttir et al., 2016). This report will be presented a sensitivity analysis to evaluate the uncertainty of the input parameter to examine the project performance. The most effective way to present a sensitivity analysis is by plotting sensitivity graphs, where the slope of the variables plotted show how sensitive the output is to a change in each variable. To evaluate the risk of the scenarios, a sensitivity analysis of scenario V was carried out considering the similar outcomes and performance of the financial assessment model for the proposed scenarios to develop the San Vicente power plant project. Figure 7-13 shows sensitivity graphs for NPV and IRR for equity and capital, for scenario V, where the uncertainty of the equipment investment, power production, electricity price and the O&M expenses (OPEX) are analysed.

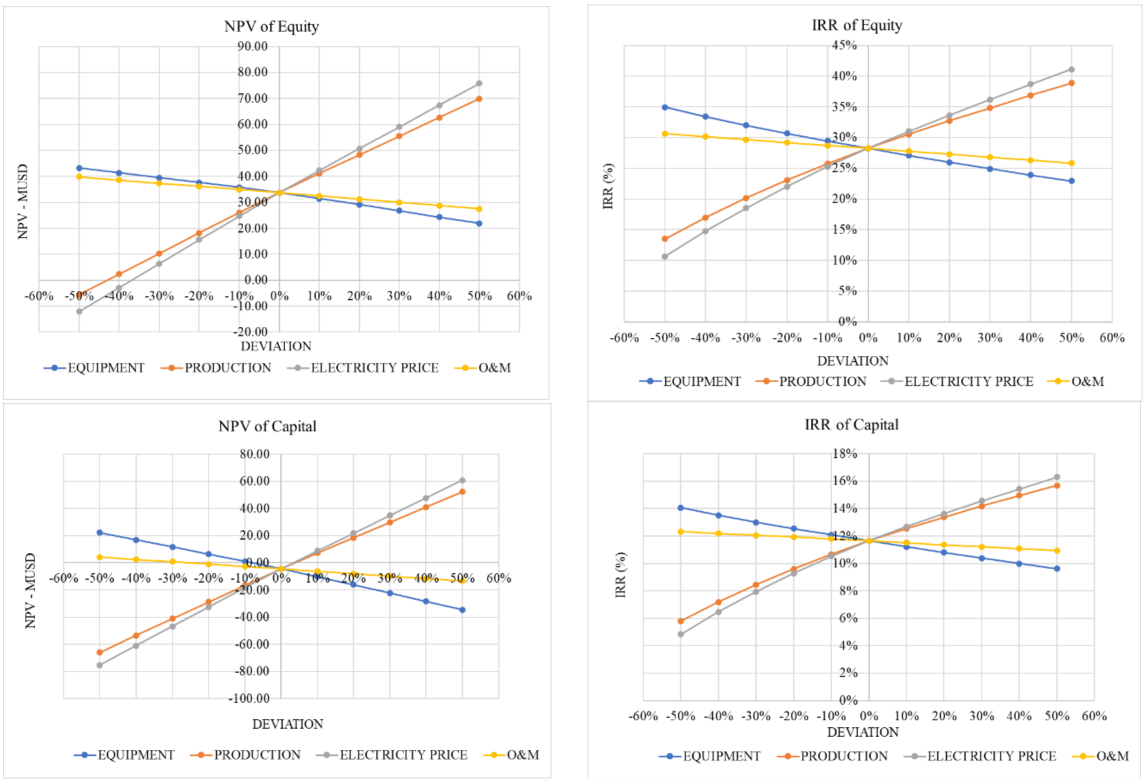


Figure 7-13 Scenario V - NPV and IRR for equity and capital investment

The sensitivity analysis determines that the electricity price and the power production are the most sensitive parameters, and the O&M expenses (OPEX) are the least sensitive inputs.

This chapter has estimated the project cost based on the AACE recommendation for the project maturity. The methodologies applied to estimate the project's components cost are described. A financial model utilizing the estimated cost and the planned horizon of the project has been done. The result of the financial key performance indicator and financial ratios are presented for the scenarios proposed to develop the project, and the result proves that the investment is feasible for both the project owner and the lenders.

Additionally, all the scenarios are economically feasible to undertake for both lenders and project owners. In addition to this, utilising scenario IV seems to be the most suitable option to develop the project. Utilising only the binary cycle units, scenario V, requires more capital expenditure and seems not worth pursuing. However, the financial project's performance is similar to other technologies, becoming an option to develop the San Vicente project.

The electricity market price is one of the most sensitive input parameters of the model. From the plotting sensitive graphs (Figure 7-13), the minimum value of electricity price that the project for scenario V can sustain is 90 USD/MWh.

SUMMARY AND CONCLUSION

The production of electricity from renewable energies will grow 15% in the power mix of the global electricity generation by 2040 according to IRENA and geothermal projects are taking part in this, representing 1% of the renewable investment. The geothermal installed capacity of El Salvador is 204 MW, and the country is planning to increase its capacity by 80 MW by developing the San Vicente and Chinameca geothermal fields.

Historically, geothermal projects were developed without clear guidelines. Nowadays, there are different methodologies between countries and developers. This report has compared the number of phases required to develop a geothermal project from different actors to finally describe nine key development phases based on the literature review and modified from the ESMAP Geothermal Handbook structure.

Today is a common practice when the reservoir capacity is known, a stepwise development strategy is applied, meaning that the activities to develop a geothermal project are divided in time and consist of developing the same activities in more than one step. This stepwise strategy might start once the capacity of the first production well successfully drilled is known and the project will be able to start generating electricity and monitoring the reservoir to record data to update the conceptual model and drilling plans for other phases.

For a small country like El Salvador, where the energy production depends on fossil fuels, applying the stepwise strategy and utilising relatively small units to develop the geothermal projects can contribute to the energy matrix, playing an important rolled as a based load power plant.

Developing a geothermal field is a complex task that requires and involve different efforts from scientists, technicians, engineers, administrators, environmentalists, lawyers, and financiers, to analyse and prepare reports to plan milestones needed in each phase of the project. A feasibility study collects all expert reports in one document that provide the necessary information for an investment decision. The feasibility study is written to provide confidence with well explained and supported evidence of the project´s viability for both the developer and potential financier. A comprehensive project appraisal is often required for the financiers, and a third-party specialist firm or consultant gets involved.

This report has focused on the technical and feasibility aspects of developing the San Vicente geothermal project and can serve as a guideline to prepare a coherent geothermal feasibility study. The proposed structure is based and modified from the typical structure presented by the MPIFS, which is in line with the most recent report to prepare feasibility studies for financing geothermal projects with an overview of the best practice focus to develop geothermal projects for electricity production published by ESMAP.

From the project concept and background can be determined that the San Vicente project owner is LAGEO, S.A. de C.V. The company has the concession rights to manage and utilise the geothermal resources for San Vicente geothermal fields. Additionally, the main project's goal is to utilise, in a sustainable way, the geothermal resource available in the field and contribute to increasing the renewable energy share in the electricity market. This objective fits with the strategies of the National Energy Policy.

In El Salvador, geothermal energy has been observed without any change and has maintained an average generation of 1,435 GWh in the last ten years. El Salvador has highly depended on thermal power generation and is the largest power supply used in the country besides the electric imports. It is expected to be reduced by incorporating the new renewable projects and the LNG plant under construction into the electricity matrix.

It is observed that the El Salvador electricity market has clear and robust frameworks, regulations, and laws to develop the electricity market. However, based on the production cost, the electricity price is forecast to establish an average price of 90 USD/MWh due to the new renewable projects and the LNG plant operating in 2022. Two recommendations can be addressed for this project. The first is to look for the most suitable power contract agreement in the market to guarantee the project feasibility to reduce the risk of electricity price fluctuation, and the second is to register the project at the national institutions to take advantage of the country tax incentives.

The geoscience surveys, drilled well data, and wells surface discharge results have confirmed a high-temperature geothermal reservoir with a good permeability identified by the mineralogical alteration, fractures, and fault zones targeted during the drilling work. At the same time, all this information is the basis for preparing the conceptual model and the resource assessment of the geothermal reservoir. The resource conceptual models and estimation capacity are the support to help the project developer to evaluate the reservoir's risk.

The conceptual model and the resource assessment serve as the basis to set the drilling targets for the next phases of the project development. From the reservoir's resource assessment, which assumes a lifetime of power production of 30 years and reference temperature of 100 °C, it can be concluded that the San Vicente geothermal project can sustain a production capacity close to 30 MW.

The harnessing development plant for the San Vicente geothermal project is planned to be developed in two stages. The first stage has included the installation of the first unit (in the range of 10 MW) to harvest the steam available to date from wells SV-5A and SV-5B and continuing with the drilling work of the wells to produce the required steam for the second unit to be installed in the second stage (in the range of 20 MW). The second stage will also include the drilling work for the production and reinjections wells required to complete the estimated capacity. Following this stepwise strategy, the goal is to fully develop the field utilising the most suitable technology for each stage until its estimated capacity of 30 MW is reached. The back pressure, single flash and binary cycle units are the three types of power plant technologies modelled following the harnessing plan. Determining that the power output for stage I are: for the back pressure cycle is 6 MW, for the single flash cycle is 12 MW, and the binary cycle is 10 MW. The power output for stage II are: for the single flash cycle is 22 MW, and the binary cycle is 19 MW. These results accomplish the estimated power capacity of the project.

Utilising the AACE recommendations to estimate the project cost according to its maturity. The San Vicente project is classified in estimation costs Class4, and the project's cost can be updated as the project has a level of definition.

The financial assessment model is an critical part of a feasibility study, its objective is to demonstrate that the project will have a financial basis and deliver acceptable returns to the project developer, and reduce the project risk assessment of the financier. A financial model uses inputs in the form of data and assumptions about variables and parameters defining the project and produces outputs from which the project feasibility can be assessed. The capital investments or expenditure (CAPEX), operating expenses (OPEX), and their distribution over the project life are the inputs parameter to the financial assessment model. It is common practice contract a third-party specialist to validate the input data and assumptions used for the model.

Transferring the risk to a well-known construction firm, able to define and control the main aspect of the power plant based on the resource parameters and location of the project, can be considered a best practice in the geothermal industry. By shifting the project risk, the bankability option increases. For the San Vicente project, this report recommends using an EPC project delivery method.

From the breakdown structure of the San Vicente project total cost, the power plant constitutes the higher share followed by the the field development, and test drilling and feasibility. The cost for equipment and construction of single flash and binary units ranges between 44 to 53%, and the drilling activities range between 31 to 37% of the total investment cost. Aditionally, the specific cost of development scenarios presented in this report ranges from 4.5 to 6.5 MUSD/MW.

The financial model, using a dynamic spreadsheet program on Microsoft Excel to evaluate the project's financial performance, is more accessible and less time-consuming to update when the model input assumptions change as the project progresses. The clearest, effective and easy way to construct is to use an architecture based on several blocks or modules.

The results of the project's key performance indicators and financial ratios demonstrated that the geothermal power project is both economical and financially feasible as it generates returns and a solid ability to covert debt payments from the cash flow. Additionally, from the sensitivity analysis is determined that the electricity price and the power production are the most sensitive parameters of the project.

Finally, utilising scenario IV seems to be the most suitable option to develop the project.

"It is possible to fly without motors, but not without knowledge and skill." W. Wright

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