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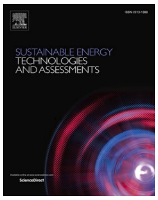

Original article

Techno-economic analysis of a proposed 10 MW geothermal power plant in Fiji

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ABSTRACT

Climate change related issues affect energy infrastructure of island nations on a regular basis. Fiji, a miniscule emitter, has set a net-zero national target by 2050 and geothermal power plant (GPP) is a possible renewable energy technology to meet this target. However, there are no feasibility studies for GPP in Fiji. The main objective of this paper is to conduct a techno-economic-environmental feasibility study of a proposed 10 MW organic Rankine cycle (ORC) GPP using the RETScreen tool. The modelling results show that 78.9 GWh of electricity can be produced that can reduce 39,461 $tCO_{2\text{-eq}}$ emissions for Fiji's energy sector. Three scenarios were modelled to study the effect of different incentives (electricity export rate, clean energy production incentive rate, emission trading rate, and renewable energy capacity development incentive) on the project's financials. The current study is the first country-specific study done in ORC GPP in Fiji and the results can inform and help potential investors, donors and government agencies make judicious decisions on geothermal power development. The study recommends that apart from financial factors, other factors, such as capacity building of key stakeholders and a conducive regulatory environment, are essential to promote GPP.

Introduction

Small Island Developing States (SIDS) are extremely vulnerable to climate change and global warming impacts. They are heavily dependent on fossil fuels for their energy needs, and in most countries these fuels are imported at a significant cost to their Gross Domestic Product (GDP) [1]. To combat climate change, the world leaders signed the Paris Agreement in 2015, demonstrating their commitment to reducing greenhouse gas (GHG) emissions and limiting global warming to less than 1.5 °C above pre-industrial levels. However, a stocktake of the Nationally Determined Contributions (NDC) of countries shows that the NDCs fall short of reaching the 1.5 °C target and the Glasgow Climate Pact at COP26 requests Parties to revisit and strengthen the 2030 targets in their NDCs by the end of 2022 to align with the aim of keeping the temperature rise to below 1.5 °C [2] and Allam et al., [3] recommends deep-decarbonisation and adequate financing. Therefore, it is imperative to exploit all viable energy generation options to meet the rising demand and curb GHG emissions. In addition, the IPCC special report on renewable energy and climate change mitigation recommends various renewable energy technologies to maintain global warming to 1.5 °C above pre-industrial levels and geothermal power production is one of the renewable options [4]. The global installed capacity of geothermal power plants is 14.1 GW as of 2020 with the U.S. in the lead, followed by Indonesia, Philippines, Turkey and New Zealand [5].

The main advantage of geothermal power plants (GPP) is that they can supply baseload power and reduce the need to operate conventional fossil-fueled power plants. However, geothermal resources are not present in all countries but in specific locations such as the Pacific Ring of Fire and for these countries, there is enormous potential for geothermal power production. The other advantages of GPP are that it has, among other things, a high capacity factor and a relatively high lifetime. Geothermal resources can be classified according to their geothermal fluid temperature as low enthalpy resources (less than 90 °C), moderate enthalpy resources (90–150 °C) and high enthalpy resources (greater than 150 °C) [6]. Geothermal power plants are designed based on the geothermal reservoir fluid temperature. The three main types of GPP are dry steam, flash steam and binary. According to Bertani [7], 23% of the world installed capacity is dry steam GPP, 42% single flash steam GPP, 19% double flash steam GPP and 14 % binary GPP. The remaining are triple flash steam GPP and backpressure & hybrid GPP. Toshiba, Mitsubishi, and Fuji are the top-rated geothermal turbine manufacturers [7].

A dry steam GPP operates with steam (usually more than 200 °C)

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Nomenclature

EES	Engineering Equation Solver
EPC	Electricity Production Cost
ESCEA	Electric System Cascade Extended Analysis (ESCEA)
ETS	Emission Trading System
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GPP	Geothermal Power Plant
HFO	Heavy Fuel Oil
IDO	Industrial Diesel Oil
IPCC	Intergovernmental Panel on Climate Change
LCOE	Levelised Cost of Electricity
LEDS	Low Emission Development Strategy
MRD	Mineral Resources Department
NCCP	National Climate Change Policy
NDC	Nationally Determined Contributions
NDCIR	Nationally Determined Contributions Implementation Roadmap
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M cost	Operation and Maintenance Cost
ORC	Organic Rankine Cycle
PICs	Pacific Island Countries
SAM	System Advisor Model
SIDS	Small Island Developing States
Solar PV	Solar Photovoltaics
VGM	Vatukoula Gold Mine
i	discount rate
n	number of years
CE	Clean energy
Ha	Hectares
$tCO_{2\text{-eq}}$	tonnes of carbon dioxide equivalent emissions
US$	United States of America dollar
MWh	Megawatt hours

piped from underground to directly run a turbine/generator unit. Due to its high temperature, it is one of the simplest designs, least expensive and relatively higher efficiency than other GPP [8]. However, it is hard to find such a high-temperature geothermal resource. In addition, running hot steam from the Earth over turbine blades leads to corrosion, increasing the power plant's operating expenses [8]. Flash steam GPP is where hot water flows (usually at temperature higher than 182 °C [9]) from geothermal reservoirs and as it rises, pressure decreases, resulting in some hot water turning into steam. This steam is separated from the water and used in turbine/generator with the left-over water and condensed steam injected back into the reservoir for single flash steam GPP [10]. The remaining liquid is expanded again at lower pressure in double flash steam to recover more energy [8]. The final configuration of GPP is the binary organic Rankine cycle (ORC) GPP. In ORC GPP, thermal energy from geothermal fluid (usually 107–182 °C) is transferred to a secondary working fluid through a heat exchanger [10]. The vaporised working fluid is used to run turbine/generator. The steam out of the turbine is condensed using either air coolers or surface water cooling systems or wet type cooling towers or dry-type cooling towers [11]. After passing through the heat exchanger, the geothermal fluid is used to pre-heat the working fluid returning from the condenser and return to the injection well.

The disadvantages of flash and dry steam GPPs are that they require very high geothermal fluid temperature that may not be present in Fiji where geothermal resources are present. Also, turbine blades of dry steam GPPs could corrode because they are in direct contact with steam that consists of impurities and chemical elements [9]. Typically all geothermal energy are considered a clean source but flash or dry steam GPPs release non-condensable gases (such as carbon dioxide and hydrogen sulphide) that come from geothermal fluid into the atmosphere [12]. In addition, drilling costs account for the largest share of GPP project costs. The drilling costs for flash and dry steam GPPs are relatively higher compared to binary GPP because binary GPPs reservoirs are located closer to the surface [12].

Binary ORC GPPs are gaining attention in locations where the geothermal fluid temperature is not very high but can still produce significant energy to meet the base load. Other advantages of binary ORC GPP are (i) there are no harmful emissions from binary ORC GPP to the environment because geothermal fluid is circulated in a closed loop and geothermal fluid heats a secondary fluid in the heat exchanger that vaporises, and then the secondary vapour goes to the turbine for electricity generation, (ii) there is low mechanical stress on the turbine due to low temperature (iii) turbine blades will not erode because there is no moisture during vapour expansion in the turbine and (iv) due to its relatively small size, ORC GPP is cheaper [13]. In addition, geothermal driven ORCs have low payback periods and these systems can lead to high energy efficiency [14]. Further, binary plants are usually constructed in small modular units depending on financial resources, capacity, and resource. These modular units can be linked to create few tens of megawatts of power plants [15]. These are the reasons why this study considers binary ORC GPP and for small island countries that have limited financial resources can opt for modular type ORC GPP.

In terms of the environmental effects of GPP, it is widely accepted that geothermal is a relatively clean source of energy. However, CO_2 emission occurs at the separator that separates hot water and steam in the GPP [16]. Computer modelling showed that a significant amount of CO_2 is discharged to the atmosphere due to the operation of a geothermal plant. The average emission is 123 g of CO_2/kWh of energy produced for geothermal plant, 1030 g of CO_2/kWh of energy produced for subcritical circulating fluidised bed coal-fired power plant and 580 g of CO_2/kWh of energy produced for an open cycle gas-fueled power plant [17]. A comprehensive life-cycle analysis of a 5.5 MW GPP in Germany identifies leakages of used refrigerants and allocation of energy consumption during construction and operation [18]. It found out that only a 1% leakage in refrigerant causes 24.6 $gCO_{2\text{-eq}}$/kWh. Therefore, the study recommends using refrigerants with low global warming potential and resource-saving drilling with electricity instead of diesel.

Several researchers have studied the thermodynamics of different types of geothermal power plants to determine their reliability, efficiency, and costs. Zarrouk and Moon [19] report mass flow rate of geothermal fluid, temperature and other parameters for 96 different GPP installed worldwide. They concluded that the average conversion efficiency of geothermal power plants is 12%, while the capacity factor when operated at its full capacity, is 80.1% for single flash-dry steam GPP, 91.5% for double flash GPP and 92.7% for binary GPP. They report that for a 10 MW installed capacity of a binary GPP, the mass flow rate is 1054 t/h, the temperature in is 136 °C and the output temperature is 58 °C.

Thermodynamic performance of a two-leveled binary organic Rankine cycle (ORC) 24 MW GPP (air-cooled) in Turkey is comparatively evaluated using the exergy analysis and optimisation method by [20]. The study results show that the total exergy efficiencies of the conventional exergy analysis, advanced exergy analysis, and artificial bee colony are 39.1%, 43.1%, and 42.8%, respectively. Further to increase the efficiency of the 24 MW GPP and the energy production, Cetin et al., [21] describes the operation of the GPP and uses a thermodynamic model to study the exergy of the system under different and changed conditions by controlling flow rate, pressure and non-condensing gas

(NCG) content at different locations of the GPP. Their results show that the proposed proportional integral derivative control strategy increases power production by 23% and exergy efficiency of the system by 26%. A two-stage ORC 5.5 MW GPP has been in operation since 2013 in Southern Germany and operates with a production temperature of 138 °C, mass flow rate of 120 kg/s of geothermal fluid and ambient temperature of 8 °C [18,22].

Heidarnejad et al., [23] applied thermo-economic evaluation using mathematical model and Engineering Equation Solver (EES) software to investigate the viability of the plant. They found that binary GPP combined with desalination system has the potential to generate electric power and freshwater with energy and exergy efficiencies of 13.86% and 19.39% respectively. They also found that each exergy unit of power and freshwater costs are calculated to be $23.17/GJ and $16.97/GJ. Another study by Bhagaloo et al., [24] used multiple decision criteria to assess the techno-economic and environmental viability of geothermal energy in Dominica for sustainable energy transition. The thermo-economic analysis of an existing binary geothermal-solar trough power plant was done using a coupled model implemented in EES. Results show that the constant-flow solar trough system has 5.5% and variable-flow solar trough system had 6.3% higher power output compared to the sole geothermal system. At the same time, the levelized cost of energy was US$64.98/MWh, US$64.73/MWh and US$66.02/MWh for constant-flow solar, variable flow solar and sole geothermal respectively [25]. In addition, modeling using EES was also conducted by Mosaffa et al. [26] to carry out thermo-economic analysis for different ORCs geothermal power plant and LNG cold energy.

Other researchers have used Aspen Plus software for carrying out thermodynamic and economic analysis of a pre-feasibility study of a binary GPP [27] while Aneke et al., [28] have used IPSEpro model to study the performance of Chena ORC geothermal power plant. Moya et al., [29] has used RETScreen software (a widely used software in energy studies for benchmarking, feasibility and performance analysis of different energy systems [30]) to conduct a techno-economic feasibility study for a 22 MW binary geothermal power plant in Ecuador. It was found that direct applications, public incentives and clean funding mechanisms are essential for the success of geothermal energy projects in the Ecuadorian context [29]. It is noted that there are not many geothermal power plant feasibility studies carried out using RETScreen, however, RETScreen was used to analyse a few direct heat applications [31,32].

Geothermal energy potential in the Pacific

McCoy-West et al., [33] carried out desktop review of public information on geothermal development potential in 20 Pacific Island Countries (PICs). They found that two countries (Papua New Guinea and Fiji) have high potential for geothermal utilisation, three PICs (Vanuatu, Solomon Islands and Northern Mariana Islands) have high-moderate potential while another 3 (Samoa, Tonga and New Caledonia) have moderate potential. They further recommended additional feasibility studies to assess geothermal resources to produce electricity. Castlerock [34] reports that Efate island in Vanuatu has 3 sites where the combined geothermal power generation is 32 MW from 3 sites and carrying out an economic analysis of a potential 4 MW and 8 MW GPP yields levelised cost of electricity as US$285/MWh and US$225/MWh respectively. In addition, Rakau [35] reports that an environmental impact assessment has been carried out at the 3 sites for exploratory drilling and approved. However, no further report has been available on the public domain on the progress and development of geothermal power in Vanuatu. For Solomon Islands, Ward [36] discusses that geothermal power development project has been identified for Savo Island in Solomons but due to the financial constraints it is not in the government priority list. He further reports 20–30 MW potential of geothermal power generation exists but limited funds, geographical isolation and poor match between demand and supply restrains geothermal power development.

In Northerm Mariana Islands, 50–125 MW of geothermal power potential exists in Saipan based on surface area data and fluid chemistry [37] and there are plans for exploratory studies to confirm the resource availability [38,39]. Only Papua New Guinea has commissioned geothermal power plants out of all the PICs. According to Kuna and Zehner [40], PNG installed its first 6 MW non-condensing geothermal power plant at the Lihir gold mine site in 2001, in 2003, 30 MW GPP was added, and in 2005 another 20 MW extension was done due to the success of the earlier extension. They further noted that the country does not have any geothermal specific legislation and the Lihir GPP used the Mining Act for its development. The 50 MW GPP addition at Lihir island is operating under clean development mechanism (CDM) and it has the potential to replace 411 GWh of heavy fuel oil generators and reduce emissions by approximately 279 $ktCO_{2\text{-eq}}$/annum [41].

Geothermal energy study in Fiji

Cox [42] summarises several geothermal energy resource investigations by various researchers in Fiji and concludes that Viti Levu (largest island in Fiji) has sub-surface water temperature between 95 and 115 °C of hot springs while Labasa in Vanua Levu (second largest island in Fiji) has sub-surface water temperature around 125 °C that may be used for direct heat applications due to its low temperature. Savusavu in Vanua Levu has a sub-surface temperature around 160 °C that can generate electric power. As Cox [42] recommended, for direct heat application from potential geothermal sites, plans are underway for using geothermal heat from Waikatakata hot spring for refrigeration in Natewa village and Vusasivo village in Vanua Levu [43]. Fig. 1 shows a total of 53 thermal areas (hot springs) around Fiji where the surface temperature ranges from 31 to 102 °C, which makes some of them a contender for geothermal applications [33,44]. Lal et al., [45] have used integrated multi-disciplinary geophysical methods to characterise self-potential (SP), ground temperature, and soil carbondioxide (CO_2) concentrations at the Rabulu hot spring system. Their result indicates an area of possible high thermal gradient and high reservoir temperature beneath the hot spring system and recommends investigation on the energy capacity of the reserve.

GoF [46] reports that Viti Levu has 15 MW for geothermal power generation potential. Out of which, 6.7 MW had no technical problems with power station construction. A grid-connected system with another 4 MW potential needs confirmation on road access [46]. Also, Vanua Levu has more than 23 MW of geothermal power generation potential out of which 21 MW has no problem with power station construction and grid connection as given in Table 1. However, GoF [46] did not conduct any technical, economic and environment analysis of potential GPP. License was given to two companies to do geothermal exploration in Fiji by the Mineral Resources Department (MRD), but no exploration was conducted to date. One reason could be high drilling costs during geothermal exploration study in island countries and this adds to the overall initial costs for power generation [47]. Another team of researchers developed a long-term power plan from 2015 to 2025 of Fiji's grid-connected electric systems that included identifying potential biomass sites and carrying out a hydropower potential study [48]. It had found the energy generation cost of three renewable-based electricity generation as part of its power development plan: hydropower, biomass and geothermal. The study considered construction costs of US4000/kW, US$2500/kW and US$3500/kW for hydropower, biomass, and geothermal power plants respectively. The study also recommended a feasibility study on binary geothermal power generation to be conducted [48].

Significance of this study

Fiji is an island nation with a population of just less than a million and a GDP of US$5.2 billion in 2018 [50]. It was the first country to ratify the Paris Agreement and has produced strategic planning

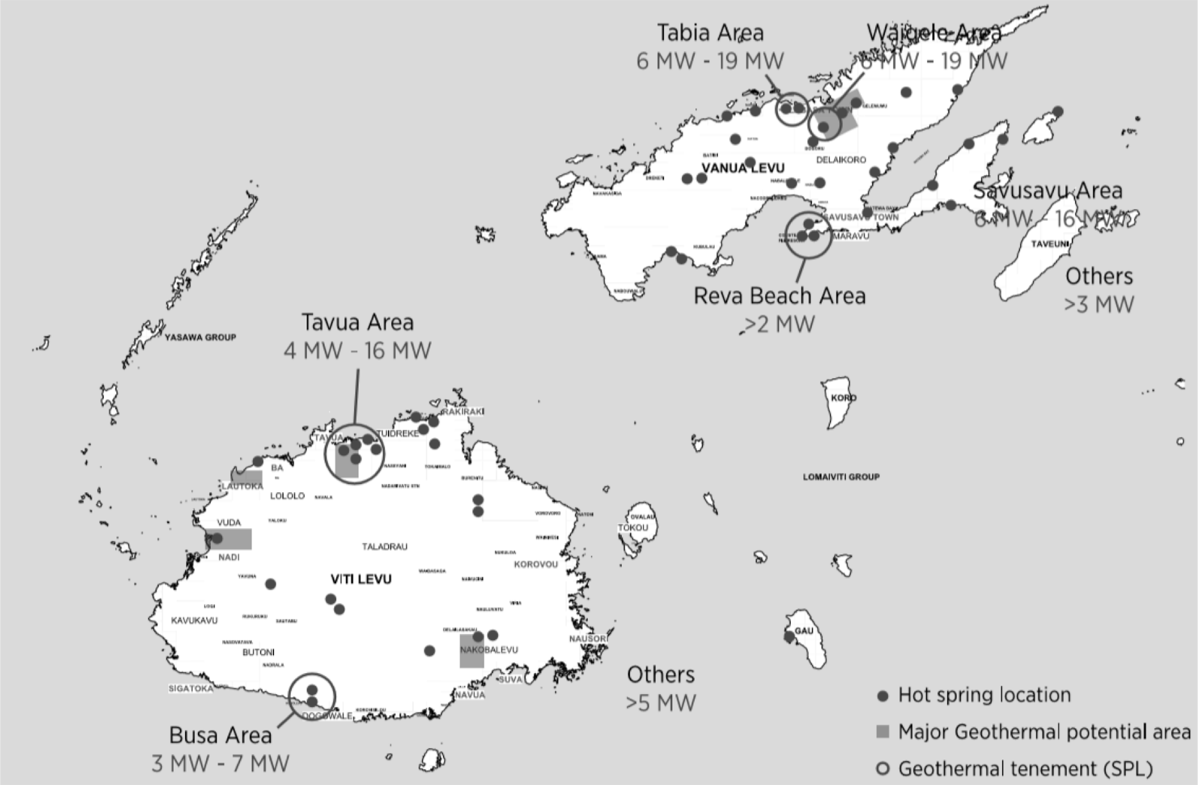


Fig. 1. Hot spring locations in Fiji, .
Source: [49]

Table 1
Geothermal energy technical potential in Fiji. .

RE source	Division	Capacity (MW)	Other comments
Geothermal			These sites have no problem with power station construction and grid connection system.
Sabeto	Viti Levu	0.5	Reservoir Temp. – 120 °C Area – 1 km × 2 km Thickness – 200 *m*
Tavua	Viti Levu	6	Reservoir Temp. – 160 °C Area – 2.5 km × 1 km Thickness – 400 *m*
Rabulu	Viti Levu	0.2	Reservoir Temp. – 110 °C Area – 1 km × 1.5 km Thickness – 200 *m*
Savusavu	Vanua Levu	8	Reservoir Temp. – 170 °C Area – 2.5 km × 1 km Thickness – 400 *m*
Rava Beach	Vanua Levu	2	Reservoir Temp. – 185 °C Area – 1 km × 1 km Thickness – 200 *m*
Tabia	Vanua Levu	2	Reservoir Temp. – 150 °C Area – 1 km × 1 km Thickness – 400 *m*
Waiqele	Vanua Levu	8	Reservoir Temp. – 150 °C Area – 2.5 km × 1.5 km Thickness – 400 *m*
Vunimoli	Vanua Levu	1	Reservoir Temp. – 130 °C Area – 1 km × 2 km Thickness – 200 *m*

Source: [46]

documents, such as the Low Emissions Development Strategy 2018–2050 (LEDS) report and the Nationally Determined Contributions Implementation Roadmap (NDCIR), that pave the way for Fiji to achieve low carbon development in all the sectors of the economy. It also has revised its 2012 National Climate Change Policy (NCCP) and launched the revised NCCP in 2018. The revised NCCP sets out the Fijian government's position on climate change adaptation and mitigation by providing objectives and strategies to protect people, the environment, and the economy. NCCP also identifies eight core principles to guide the policy namely; sustainable well-being, social cohesion, inclusivity, partnership, agility, transparency and communication and integrated learning [51]. In 2021, Fiji also passed its Climate Change Act that sets a legal framework to enable work on climate change mitigation, adaptation, measurement, reporting and verification of greenhouse gas inventories and disaster risk management [52,53]. To date, there have been numerous studies in Fiji related to wind energy potential in Fiji [54–56], biomass energy [57–59], solar energy potential [60–62] and hydro power potential [63]. However, feasibility study on geothermal energy for power generation is lacking.

From the literature survey in previous paragraphs, it is noted that many researchers have used EES software to carry out thermo-economic analysis of hybrid geothermal power plants. No study is done in the Pacific region that has challenges unique to the region such as geographical isolation between islands and the developed nations, smaller economy, lack of capacity and expertise, and uneven distribution of demand. Moreover, there is a lack of pre-feasibility study in the PICs where geothermal resource exists. Thus, our study uses Fiji as a case study to inform and promote sustainable energy development in PICs. This study uses data on geothermal fluid temperature data of Fiji and the project costs contextualised to Fiji to carry out a technical and financial assessment. With the international commitments on GHG reduction and Fiji's national targets to reach net-zero emissions by 2050 and 100% of electricity generation from renewable sources by 2036, this current study is well placed to provide evidence and information to potential developers, investors and financial institutions about the costs, energy generation potential and emission reduction potential from geothermal power plant development.

So, to fill the gap in the literature about geothermal power plant feasibility study in Fiji and to contribute to Fiji's national goals and international commitments, the main objective of this work is to (i) carry out a techno-economic-environment feasibility study of an ORC GPP, (ii) explore the impact of different levels of incentives on the net present value and the electricity production cost of GPP and (iii) discuss the barriers and policy implications of GPP development in Fiji. The main advantage of this study is that it studies an alternative electricity generation source that can diversify the electricity generation portfolio for Fiji. This will help achieve energy security and reduce Fiji's dependence on costly imported fuel oils while also reducing the nation's carbon footprint. This study will also help provide results to policy makers to formulate enabling policies such as tax incentives and clean energy production incentives to promote geothermal energy development. Neighbouring island countries with geothermal resources can also use this methodology to help develop and diversify their electricity generation sources and achieve ambitious climate action targets. The next section of the paper sets the scene for Fiji's electricity generation, followed by section 3 describing the methodology and data input for modelling. Section 4 presents the results, followed by the discussion section. Finally, some conclusions are made.

Fiji's current electricity demand and supply

The grid electricity generation in Fiji accounts for 22.7 % of the total energy sector emissions. This seems relatively low now but considering Fiji's ambition to achieve net-zero emissions by 2050, Fiji needs to diversify and expand its renewable electricity generation portfolio because electrification of the transport sector will increase the grid electricity demand. As seen in Fig. 2, hydropower dominates the generation mix with an annual average of 52% of total power generated followed by industrial diesel oil (IDO) and heavy fuel oil (HFO) power generation with an average of 44% while biomass electricity is 3% and the remaining is from a wind farm. It can be noted from the same figure that the total generation in 2020 decreased by 8%, mainly due to reduced demand from non-domestic (commercial and industrial) customers as trading hours were significantly affected by the COVID-19 pandemic. Electricity generation from renewable sources in 2020 was almost at the same level as past years, but there was a reduction in IDO and HFO consumption. Apart from the utility side generation, there are "behind the meter" solar PV installed in commercial buildings with a capacity reaching 4 MW [64]. However, the amount of electricity generated from these facilities are not available on any publicly available database.

Geothermal energy is one of the resources that need to be considered to enhance energy security, diversify Fiji's electricity generation portfolio, and contribute to Fiji's national goals and international commitments. Fiji's draft national energy policy 2013 prioritises geothermal resources for power generation and recommends further research to identify potential geothermal projects [65]. In addition, JICA [48] reports geothermal power as the most economical source for supplying baseload power while middle load can be supplied by run-of-river hydropower plant and peak load supplied by reservoir type hydropower plant. However, it should be noted that for JICA's study, the economics study considered only the construction cost of the geothermal power plant and not the geothermal exploratory studies costs.

Fiji's electricity demand for the grid is divided into four types of customers based on the tariff charged to them by the power utility company in Fiji. Domestic customers, commercial customers (whose maximum demand is less than 75 kW), industrial customers (maximum demand more than 75 kW), institutions (schools and churches) and streetlights. On average, the non-domestic demand is 72% of the total grid electricity demand. Some facilities are on the main island but are not connected to the grid. The main reason is that these, mainly industrial, unit's power demand is very high and would place a considerable burden on power utility to supply power cost-effectively.

One such entity is the Vatukoula Gold Mine (VGM) located in the Northern part of the main island, Viti Levu. It has a 19 MW diesel generator capacity that caters to the mining site's electricity demand. The total energy generated and the fuel consumption by the mine operations in a typical year is shown in Fig. 3.

The total annual electricity generated at VGM for the period was 85.3 GWh, about 10% of Fiji's total grid electricity generated. The annual diesel oil consumption for VGM was 22 million litres with average monthly consumption of 1.84 million litres. The major energy consumers within the mine are the Vatukoula Treatment Plant (VTP) and pumps for dewatering the underground surfaces as shown in Fig. 4. VTP is where all the process happens for extracting gold from rocks.

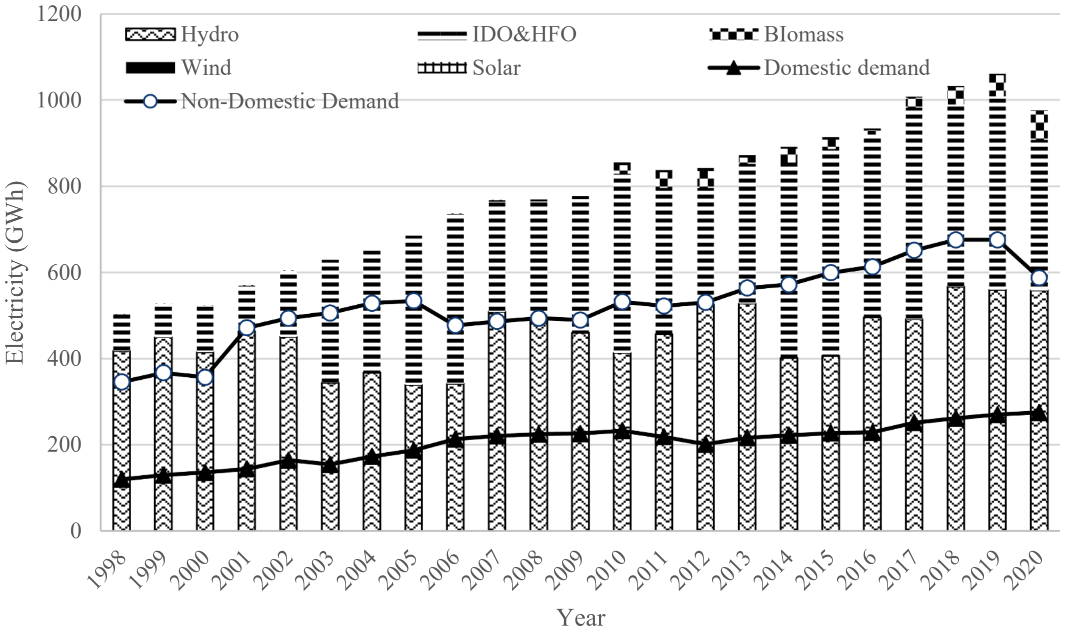


Fig. 2. Grid electricity generation and demand. Data .
Source: [50,66]

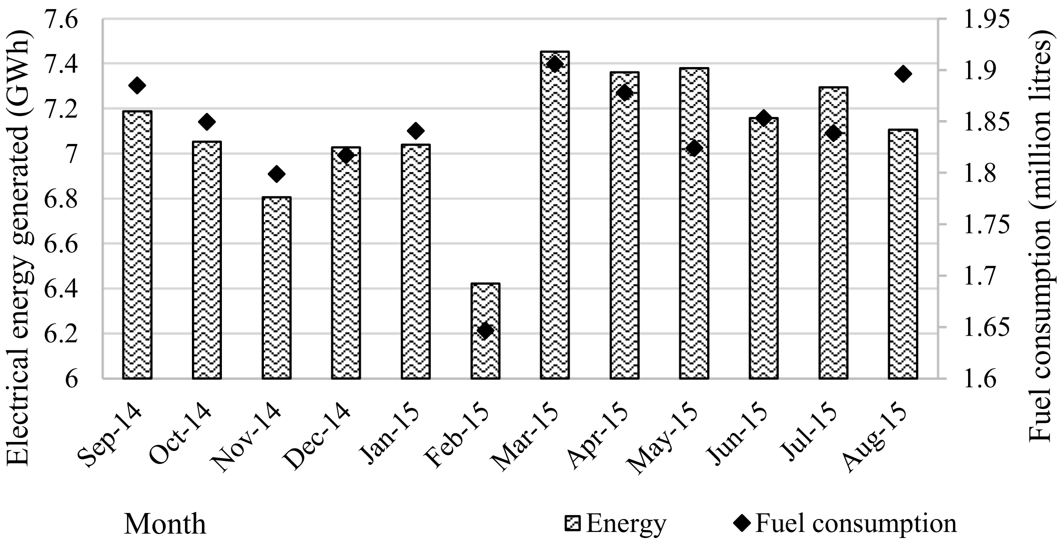


Fig. 3. Monthly electrical energy generated and fuel consumption at VGM. Data .
Source: [67]

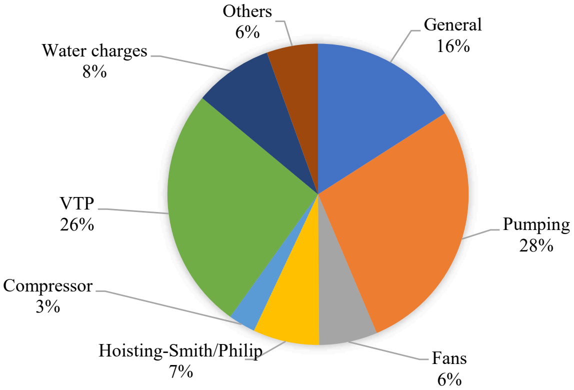


Fig. 4. Share of electricity demand by different process at VGM for September 2015. Data .
Source: [67]

Recently, VGM has installed heavy fuel oil generators to increase the electricity supply to its operations [68]. However, the authors were unable to get information on the exact capacity of industrial diesel oil and heavy fuel generators operating at VGM.

As seen above, diesel and heavy fuel oil generators are the only power supply technologies used at the mine. Considering the availability of renewable energy resources, it will be useful to explore other technologies such as solar PV or geothermal to supply electricity to the mine. So, the next section explores the pre-feasibility of 10 MW ORC GPP in Fiji.

Method

To carry out a pre-feasibility study for a proposed 10 MW ORC GPP, the project site is selected at Waikatakata, Tavua, approximately 19 km from Vatukoula Gold Mine. A 10 MW power plant is chosen because, according to Fig. 1 and [46], a 4–16 MW of geothermal power potential exists at the site. RETScreen is used to carry out techno-economic and environmental analysis of the 10 MW ORC GPP. RETScreen software is a clean energy management tool that can be used to do benchmark studies, feasibility studies of different types of systems (either energy demand or energy supply), economic analysis and risk assessments of projects [30]. Researchers have used RETScreen to assess (technical, environmental and financial) domestic solar water heating system [69], off-grid solar PV [70], grid-connected solar PV [71–73], hydro power [74], wind power [75] and geothermal power plant [29]. Many researchers use the RETScreen tool in many countries because of its ability to analyse multiple dimensions of a project such as technical, financial, and environmental [76]. In addition, RETScreen can validate the techno-economic and environment sustainability of clean energy projects [71].

For this study, an ORC GPP as shown in Fig. 5 is considered as the reservoir temperature at the selected site is around 160 °C as seen in Table 1. The basic components of an ORC system are evaporator, turbine, condenser and pump [77]. The geothermal fluid flows from the production well into the evaporator and vaporises secondary working fluid which is in another loop. Finally, the geothermal fluid returns to the injection well. In contrast, the organic fluid (secondary working fluid whose boiling point is lower than water) vaporises to run the turbine blades which is connected via a shaft to the generator to produce electricity. The spent vapour from the turbine enters the condenser, which turns the vapour into a liquid phase. This liquid is then pumped into the evaporator, completing the closed cycle to repeat the process. A wet

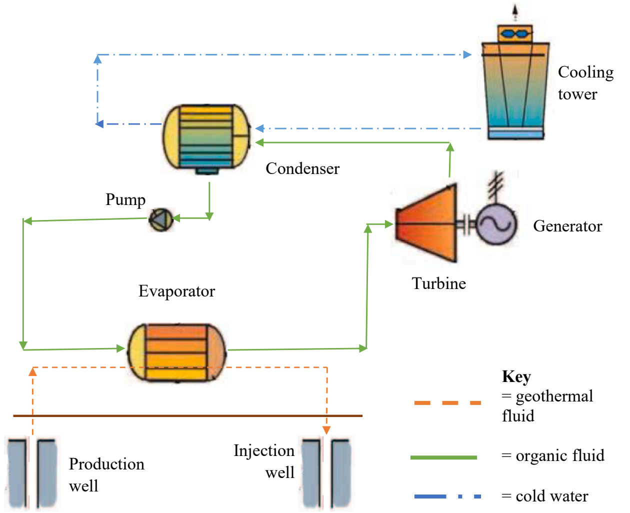


Fig. 5. Schematic diagram for ORC GPP.

cooling tower is the most common cooling system for GPP to increase efficiency. In a wet cooling cycle, the coolant fluid (water) goes through the cooling tower to dissipate heat stored and passing through a cooling tower, the water, which runs gravitationally from the top of the tower, is cooled down by a fan, using the outside air [78].

Technical details used in the RETScreen modelling are shown in Table 2. For data specific to Fiji, the reservoir temperature is taken as 160° as shown in Table 1 sourced from [46] and the cost data are specific to Fiji as reported by various literature. In addition, the results from the RETScreen simulation are compared with System Advisor Model (SAM) to validate the results. SAM is a free software developed by National Renewable Energy Laboratory (NREL) that can perform detailed analysis of a renewable energy system's performance analysis and finance analysis. Numerous researchers have used it to carry out techno-economic assessment of solar power plants, geothermal power plant and hybrid solar-geothermal power plants [79–83].

JICA [48] reports the construction cost of a typical geothermal power plant in Fiji as US$3,500/kW and annual O&M as US$406.30/kW/year. However, this report does not clarify if the exploration cost of geothermal was also considered in the capital cost. It also reports 30 years as the lifetime of a geothermal power plant. Given that Fiji does not have any existing rigs in Fiji, the initial capital cost can be as high as US$6,000/kW [49]. They report that investment costs are made of 4 main components (i) exploratory drilling costs (US$1,200/m and 500 m to 1000 m of drilling needed) to confirm geothermal resource availability, (ii) drilling of production and injection wells, (iii) auxiliary facilities and infrastructure such as roads, transmission, and distribution networks, etc. and (iv) the installation of actual power plant. Hence, for the financial viability of a 10 MW GPP in this study, the capital cost is taken as US$6,000/kW and O&M cost is taken as US$406.30/kW/year. A discount rate of 10% and an inflation rate of 3.2% are considered [57]. The electricity export tariff is taken as US$0.1621/kWh, which is the minimum rate set by the Fijian Competition and Consumer Commission, the independent regulatory body for setting minimum electricity export price.

Scenario description and analysis

Three different scenarios are studied using RETScreen to study the impact on the net present value (NPV) and electricity production cost (EPC). NPV is the difference between the present value of projects' cash inflows and projects' cash outflows. Equation (1) is used to calculate the NPV [87].

$$\mathrm{NPV} = \frac{\sum \mathrm{benefits}_n - \sum \mathrm{costs}_n}{(1+i)^n} \tag{1}$$

Table 2
RETScreen input data for ORC GPP modelling.

Parameter	Value	Unit	Reference
Location	Latitude: −17.5° Longitude: 178.3°		
Steam flow rate	234,000	kg/hr	[29]
Availability of power plant	90	%	
Operating pressure	6	bars	[29]
Steam temperature	160	°C	
Back pressure	2.1	Bars	[84]
Turbine efficiency	80–85	%	[85]
Lifetime	30	Years	[86]
Costing			
Diesel cost	1*	US$/litre	
Capital cost	6,000	US$/kW	[49]
O&M cost	406.30	US$/kW/yr	[48]
Discount rate	10	%	[57]
Inflation rate	3.2	%	[57]

*Recently, Fiji has seen an increase in fuel prices and the current cost of diesel has gone up to USD1.33/litre.

where n is the number of years from the start of the system operation and i is the discount rate.

EPC also called levelized cost of electricity (LCOE) represents the electricity export rate required to have a NPV = 0, that is, the average cost of the energy produced throughout the project's lifetime. It is calculated using equation (2) [88,89].

$$\mathrm{EPC} = \frac{\sum \mathrm{costs}}{\text{annual energy production (MWh)} \times \text{project lifetime}} = \frac{\sum \frac{\mathrm{costs}_n}{(1+i)^n}}{\sum \frac{\mathrm{energy}_n}{(1+i)^n}} \tag{2}$$

The scenarios studied are:

Scenario 1 – the ORC GPP is installed and commissioned by the investor with no support other than the electricity export tariff rate given as US$162.1/MWh.

Scenario 2 – same as scenario 1 but with additional incentives. The first incentive is a clean energy production incentive of US$0.07/kWh of electricity generated from renewable resources given for the first 15 years of generation similar to [90,91]. In addition, a renewable capacity development incentive of US$300/kW is considered in this scenario; the Fijian Ministry of Economy could provide this incentive. Also, an emission trading system (ETS) is assumed to exist for this scenario. An emission trading rate of US$34/tonne [92] is considered and it is assumed that this scheme will work for 21 years. Radpour et al., [90] used US$1,000/kW in their work to study carbon price and incentives for the adoption of renewable energy technologies in the power sector.

Scenario 3 – the ORC GPP is installed and commissioned by the investor, but electricity is not exported to the grid; instead, it is used at a local facility (possibly Vatukoula Gold Mine). The same additional incentives as scenario 2 are studied in this scenario.

For each scenario, sensitivity and risk analysis were also carried out to reduce the uncertainty in the modelling outputs. To assess the viability of GPP and factor in uncertainties in input variables, sensitivity analysis was carried out. In this analysis, selected input parameters (electricity export price, debt ratio, capital costs, O&M costs, etc.) were varied with a range of ± 30% similar to [71] to study its impact on two financial indicators; NPV and EPC.

Risk analysis was carried out to see the impact of simultaneously varying input parameters on the project financial indicators. The risk analysis on RETScreen uses Monte Carlo simulations and 5,000 combinations were chosen for this study similar to the analysis performed by [71]. The histogram in risk analysis shows the full distribution of the financial indicator at a particular risk level.

Study scope and limitation

This work studies the techno-economic pre-feasibility of a 10 MW ORC GPP. It considers the broad temperature data on various hotsprings around Fiji's landscape, the technical data for ORC GPP available on published literature and costs data from published literature. It does not study geothermal resource geology, geophysics, and exploration studies. It should be noted that before the implementation of any ORC GPP in Fiji, further studies on the type and properties of working fluids, condensation temperature and pressure, cooling media, and selection of expander technology need to be carried out. In addition, solar-geothermal power plant as a hybrid system can be studied for Fiji's case.

Results

RETScreen analysis shows that the proposed 10 MW geothermal power plant produces 78,922 MWh or 78.9 GWh annually when the power plant availability is assumed to be 90% and the turbine efficiency is taken as 82.5%. It was seen that the annual electricity output depends on the steam flow rate, operating and exhaust pressures of the turbine, the temperature at which steam is extracted from the Earth, and the turbine efficiency. Hence, if the power plant capacity increases (by changing steam flow rate, operating and exhaust pressure of the turbine, etc.), then the capital costs and operation and maintenance costs increases which in turn affects the energy production cost and other financial parameters. The section below presents the results of the three scenarios and its sensitivity and risk analyses on the two financial indicators (EPC and NPV) using different input parameters.

Scenario 1: Electricity is exported to the grid and no other incentive or grant is given

Table 3 shows the base case values for different input parameters that will be used for the sensitivity analysis and the corresponding output of net present value, simple payback period and electricity production cost. It should be noted that the electricity export tariff is taken as US$162.1/MWh, and the electricity production cost must be less than electricity export tariff to make the project financially viable and attractive. It is seen from Table 3 that the EPC is US$140/MWh, which is less than the electricity export tariff of US$162/MWh. Also, the NPV is US$17.3 million indicating that the project is financially viable. The equity payback period is taken as 4 years. Equity payback is the length of time that it takes for the facility owner to recoup its own initial investment (equity) out of the project cash flows generated. The equity payback considers project cash flows from its inception and the debt level of the project, which makes it a better time indicator of the project merits than the simple payback [30].

Effect on the net present value (NPV)

To carry out the sensitivity analysis, one input variable was varied in steps of ± 5% from its base value while keeping all other input parameters constant as in Table 3. From Fig. 6, the electricity export tariff is the most critical parameter affecting NPV. For a 5% increase or decrease in electricity export tariff, the NPV increases or decreases by 35% respectively. It is also noted that NPV is negative if the electricity export tariff decreases by more than 15% compared to the base case. This means that the project will not be financially viable if the electricity export is less than US$140/MWh. The next important factor is capital cost followed by debt interest rate where both are negatively related to NPV. For every 5% increase in capital cost, the NPV decreases by 15%, whereas for every 5% increase in debt interest rate, the NPV decreases by 5%. The debt term and debt ratio have a positive relationship with NPV and affect NPV at a very slow rate.

For the risk analysis and performing a Monte Carlo simulation, the median NPV for the project is US$16.614 million. When all the parameters are varied by ± 30%, for zero risk level the NPV ranges from US$-41.79 million to US$91.39 million. Negative NPV means that the project is not financially viable, so risk level was increased to see when a positive NPV is achieved. Hence, at 40% risk level, the NPV range is positive as seen in Table 4. Potential investors must negotiate an attractive electricity export tariff rate to minimise the risk of having a negative NPV. In addition, policymakers must give incentives to reduce the risk for investors in GPP development.

Table 3
Base case input and output values for scenario 1.

Parameter	Unit	Value
Input		
Availability of power plant	%	90
Grid electricity export rate	US$/MWh	162.1
Capital cost	US$/kW	6,000
O&M cost	US$/kW/year	406
Inflation rate	%	3.2
Discount rate	%	10
Project lifetime	Years	30
Debt interest rate	%	4
Debt term	Years	20
Output		
Electricity production	MWh/year	78,922
Simple payback	Year	6.9
Equity payback	Year	4
Net present value (NPV)	US$ million	17.284
Benefit to cost ratio (BCR)		2
GHG reduction cost (GRC)	US$/tCO$_{2\text{-eq}}$	−24.27
Electricity production cost (EPC)	US$/MWh	140

Effect on the electricity production cost (EPC)

The results show that the electricity export tariff rate does not impact the EPC. The most crucial factor affecting EPC is the amount of electricity exported to the grid, which negatively affects EPC as seen in Fig. 7. The amount of electricity exported to the grid depends on the availability of the power plant for electricity generation, the turbine efficiency, and other technical details of the power plant such as steam flow rate, operating pressure and exhaust pressure of the turbine and temperature of the steam extracted from the Earth. From sensitivity analysis, it is seen that for 30% increase in electricity exported to the grid, the EPC decreases by 23% while if the amount of electricity exported to the grid decreases by 30%, then the electricity production cost increases by 43%. Hence, potential investors and operators need to note that the amount of electricity exported to the grid needs to be maintained at a financially sound level. For this, it is paramount to operate ORC GPP optimally and efficiently and to carry out all scheduled servicing and maintenance of the power plant. Capital cost is the second variable that affects the EPC, and it is positively related. With a 30% increase in capital cost, the EPC increases by 15%. Similarly, increasing debt interest rate - the interest rate used for debt repayment, by 30% (that is debt interest rate is increased from 7% to 9.1%), increases EPC by 5%.

The Monte Carlo method with 5,000 simulations was applied to carry out the risk analysis. Each parameter (initial costs (capital cost), O&M costs, electricity exported to grid, electricity export rate, debt ratio, debt interest rate, and debt term) was varied by ± 30% simultaneously to study the impact of the different variables simultaneously on the EPC.

In terms of EPC variation due to all the parameters simultaneously, a histogram similar to Fig. 8 was generated for EPC at different risk levels and results are tabulated in Table 4. Fig. 8 shows the range of EPC at 0% risk level if all the parameters are varied within ± 30%. The median EPC is US$140/MWh and the range of EPC at different level of risk is shown in Table 4. Hence, Table 4 implies that for zero risk in the project, the EPC can range from US$93.7/MWh to US$222/MWh. For all other risk levels, the EPC falls between this range.

Scenario 2: Electricity is exported at rate of US$0.1621/kWh and incentive is given for RE capacity development and clean energy production. Also, ETS is considered

The output of this scenario is given in Table 5. This table also provides the values for the base case for input parameters that will be sensitised for analysis to study its impact on NPV and EPC. This scenario is better than scenario 1 for investors because of the GHG reduction credit rate, renewable energy capacity development grant and clean energy production rate incentives are given. This led to a reduced simple payback period, increased NPV and BCR and reduced EPC compared to scenario 1.

Effect on NPV

Varying the different input parameters to study its impact on NPV showed that the impact is the same as in Scenario 1 except clean energy production incentive rate and GHG emission reduction credit rate. Hence, Fig. 9 shows the impact of these incentives on NPV. It is seen that clean energy production rate incentive has a high positive impact on the NPV, that is, as the clean energy production rate increases, NPV also increases. GHG reduction credit rate and GHG reduction credit duration have the same amount of positive impact on NPV. With a 30 % increase in clean energy production rate, the NPV increases by 18%, while with 30% increase in GHG reduction credit rate and duration, the NPV increases by 5%.

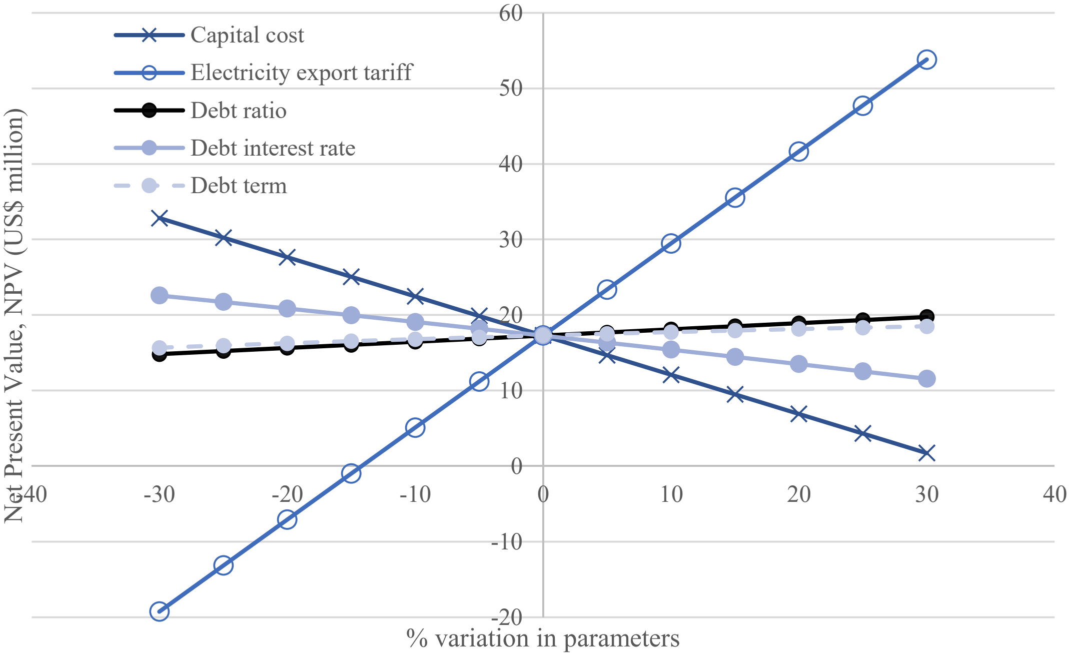


Fig. 6. Scenario 1 - Sensitivity diagram for net present value.

Table 4

Range of EPC and NPV at different risk levels for the different scenarios.

		Scenario 1				**Scenario 2**				**Scenario 3**			
		EPC (US$/MWh)		**NPV (US$ million)**		**EPC (US$/MWh)**		**NPV (US$ million)**		**EPC (US$/MWh)**		**NPV (US$ million)**	
		Median		Median		Median		Median		Median		Median	
		140		16.614		137		80.64		137		−40.54	
Level of risk (%)	Confidence level (%)	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
0	100	93.7	222	−41.79	91.39	89.9	224	21.00	164.23	87.5	215	−120.52	33.28
10	95	115.5	172	−12.83	48.97	112	168	50.42	113.61	112	168	−69.89	−10.43
20	90	120.6	165	−6.70	41.24	117	160	56.54	106.38	117	161	−63.26	−16.84
30	85	123.9	160	−2.25	36.34	120	155	61.38	101.24	120	155	−58.98	−21.27
40	80	126.8	156	1.18	32.64	123	151	65.14	97.04	123	152	−55.49	−25.32

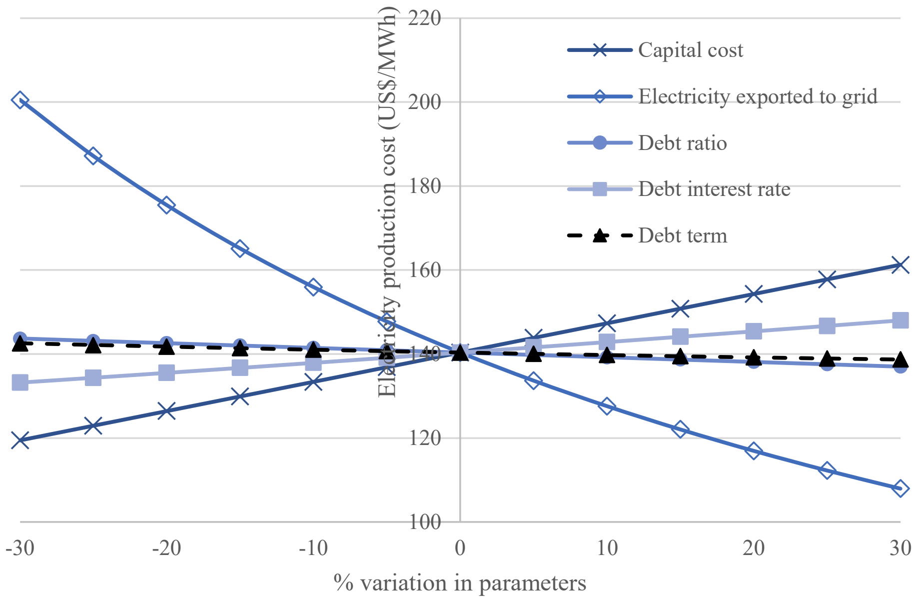


Fig. 7. Scenario 1 sensitivity diagram for electricity production cost.

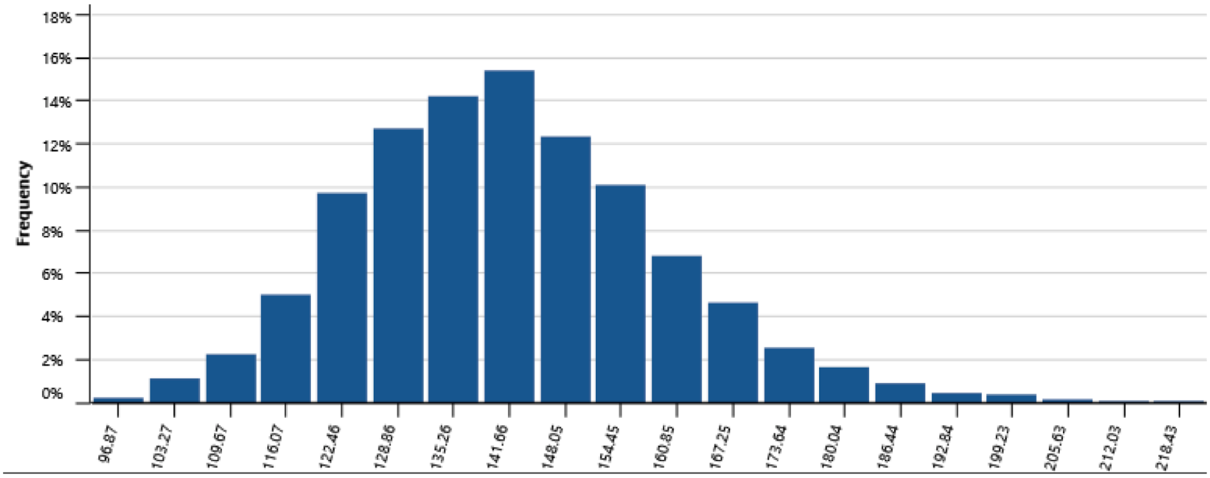


Fig. 8. Scenario 1 - Histogram of EPC range with risk level set at 0%.

Table 5
Input parameters and output of Scenario 2.

Parameter	Unit	Value
Input		
Availability of power plant	%	90
Grid electricity export rate	US$/MWh	162.1
Capital cost	US$/kW	6,000
O&M cost	US$/kW/year	406
Inflation rate	%	3.2
Discount rate	%	10
Project lifetime	Years	30
Debt interest rate	%	4
Debt term	Years	20
GHG reduction credit duration	Years	21
GHG reduction credit rate	US$/tonne	34
Clean energy production credit rate	US$/kWh	0.07
Output		
Electricity production	MWh/year	78,922
Simple payback	Year	3.7
Equity payback	Year	1.3
Net present value (NPV)	US$ million	81.427
Benefit to cost ratio (BCR)		5.5
GHG reduction cost (GRC)	US$/$tCO_{2\text{-eq}}$	−161
Electricity production cost (EPC)	US$/MWh	136

Considering the risk analysis, for 0% risk, the net present value ranges from US$20.997 million to US$164.228 million as seen in Table 4. Overall, as the percentage risk level increases, the range for the NPV decreases. However, for the different levels of risk the NPV is still positive, confirming what was said earlier; that is, project is financially viable when incentives are given.

Effect on EPC

Carrying out sensitivity analysis, the GHG reduction credit rate, its duration, and clean energy production rate do not impact the electricity production cost. However, because of the renewable energy capacity development grant of US$3 million, the energy production cost decreases to USD137/MWh as seen in Table 5 when compared to scenario 1. Other parameters have the same impact as in scenario 1 for impact on EPC.

Because RETScreen does not sensitise the renewable energy capacity development grant, its impact was manually done on RETScreen as shown in Table 6. It is seen that for increase in grant upto 20% from the base case of US$3 million, there is no change in EPC, however, when the grant is increased by more than 30%, the EPC decreases by 0.7%. In addition, a 5–25% decrease in grant leads to 0.7% increase in EPC. Similarly, ±30% variation in grants have very little impact on NPV, it just changes by ± 1.1%. However, increasing the grant by 86%, that is, from US$2.1 million to US$3.9 million, EPC decreased from $138/MWh to $135/MWh (a mere 2% decrease). Hence, to further decrease EPC, the

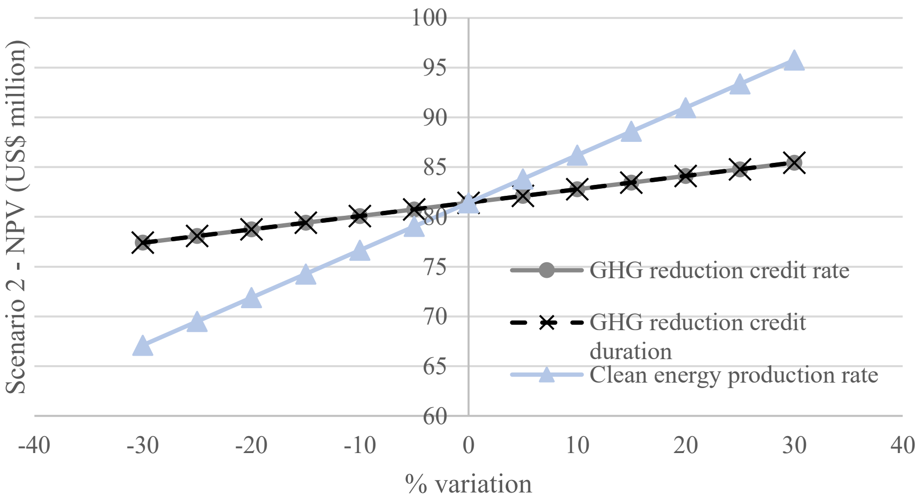


Fig. 9. Scenario 2 – impact on NPV.

Table 6

Sensitising RE development grant for scenario 2.

	Percentage variation from base case values												
	−30	−25	−20	−15	−10	−5	0	5	10	15	20	25	30
Grant (US$ million)	2.1	2.25	2.4	2.55	2.7	2.85	3	3.15	3.3	3.45	3.6	3.75	3.9
EPC (US$/MWh)	138	137	137	137	137	137	136	136	136	136	136	135	135
NPV (US$ million)	80.5	80.7	80.8	80.9	81.1	81.3	81.4	81.6	81.7	81.9	82.0	82.2	82.3

government or bilateral partners could give a higher grant to potential investors.

Overall, the median EPC for scenario 2 is US$137/MWh and for zero risk level, it ranges from US$90/MWh to US$224/MWh. While for scenario 1, medium EPC is US$140/MWh and at zero risk level, EPC ranges from US$94/MWh to US$222/MWh. This shows that EPC decreases with the additional incentive given in scenario 2.

Scenario 3: Electricity is not exported to the grid, but other incentives are available

This scenario is the same as scenario 2, that is, it has the same grants, a GHG reduction credit rate offered and the clean energy production incentive available. The only difference is that electricity is not sold to the grid in this scenario but is used where it is produced or transmitted to nearby higher load demand.

The output from modelling is shown in Table 7. With the RE capacity development grant of US$3 million, GHG reduction credit rate of US $0.34/tCO$_{2\text{-eq}}$, and clean energy production tariff of US$0.07/kWh, the project is not financially viable as seen in Table 7 because the NPV is negative and GHG reduction cost is positive.

Because electricity is not exported to the grid in Scenario 3, the EPC is not used to assess this scenario's financial viability. Instead, NPV was taken as the financial indicator to gauge the financial viability of this scenario.

Effect on NPV in scenario 3

Fig. 10 shows that the clean energy production credit rate incentive has the biggest positive impact on NPV. However, as seen from Fig. 10, the NPV is negative and to achieve a positive NPV, the clean energy production rate should be increased from the current US$0.07/kWh. Sensitivity analysis reveals that initial costs, O&M costs and debt interest rate have a negative impact on NPV, that is, as these parameters increase from their base values, the NPV decreases. The GHG reduction credit rate and the clean energy production credit rate positively impact NPV, so to achieve a positive NPV, a further analysis was done to determine at what rate these parameters should yield a positive NPV. Sensitising the clean energy production rate, yields a rate of US$0.1292/kWh at which a positive NPV is noted as seen in Fig. 11(a) where the NPV can be estimated by equation (3) where the model can explain 99.99% of the variability.

Table 7

Scenario 3 input parameters and output values.

Parameter	**Unit**	**Value**
Input		
Availability of power plant	%	90
Grid electricity export rate	US$/MWh	0
Capital cost	US$/kW	6,000
O&M cost	US$/kW/year	406
Inflation rate	%	3.2
Discount rate	%	10
Project lifetime	Years	30
Debt interest rate	%	4
Debt term	Years	20
GHG reduction credit duration	Years	21
GHG reduction credit rate	US$/tonne	34
Clean energy production credit rate	US$/kWh	0.07
Output		
Electricity production	MWh/year	78,922
Simple payback	Year	20.5
Equity payback	Year	None
Net present value (NPV)	US$ million	−40.289
Benefit to cost ratio (BCR)		−1.2
GHG reduction cost (GRC)	US$/tCO$_{2\text{-eq}}$	167
Electricity production cost (EPC)	US$/MWh	136

$$\text{NPV} = 681.72 \times \text{CE production rate} - -88.091 \tag{3}$$

where NPV is in US$ million and CE production rate is in US$/kWh.

Similarly, GHG reduction credit rate also has a positive impact on NPV. Sensitising this parameter to achieve a positive NPV, yield the lowest GHG reduction credit rate to be US$136/tCO$_{2\text{-eq}}$, Fig. 11(b). The equation for estimating is given in equation (4).

$$\text{NPV} = 0.3941 \times \text{GHG reduction credit rate} - -53.688 \tag{4}$$

For risk analysis, at 0% risk level, the net present value is positive, which means that the project is financially viable as seen in Table 4. For all other risk levels, the NPV is negative. While when all the parameters are varied simultaneously, at 0% risk level, the EPC ranges from US $87.5/MWh to US$215/MWh.

GHG emission reduction

The GHG reduction was calculated using the level 2 emission calculation in RETScreen. The fuel mix was taken to be 50% diesel and 50% for the grid electricity generation. From the modelling work, for a potential 10 MW GPP, a 39,461 tCO$_{2\text{-eq}}$ emission reduction is possible when the GHG emission factor for grid electricity generation is taken as 0.538tCO$_{2\text{-eq}}$/MWh of generation with 7% taken as transmission and distribution losses. This reduction is equivalent to 3,629 Ha of forest absorbing carbon or almost 17 million litres of gasoline not used.

From the three scenarios, the cost of GHG emission reduction is US $-24.27/tCO$_{2\text{-eq}}$ for scenario 1, US$-161/tCO$_{2\text{-eq}}$ for scenario 2 and US $167/tCO$_{2\text{-eq}}$ for scenario 3. GHG reduction costs is calculated by dividing the annual life cycle savings of the project by the net GHG reduction per year, average over the project life [30]. Further, negative GHG emission reduction cost means savings are made while GHG emissions are reduced [93]. In contrast, a positive cost of GHG emission reduction value indicates an overall cost to the investor while emissions are reduced. So, in Scenario 1, US$-24.27/tCO$_{2\text{-eq}}$ means that the project saves US$24.27 for every tonne of CO$_2$ equivalent emission reduced. In scenario 2, US$-161/tCO$_{2\text{-eq}}$ means that US$161 of savings is done while 1 tonne of CO$_2$ equivalent emission is reduced. This value is higher than scenario 1 because there are more incentives given in scenario 2 compared to scenario 1.

On the other hand, in scenario 3, US$167 of expenses are incurred while trying to save 1 tonne of CO$_2$ equivalent emissions. Cost is incurred in scenario 3 because there is less income generation in scenario 3 compared to scenarios 1 and 2. This is because in scenario 3 electricity is not exported to the grid but used locally. The only revenue received in Scenario 3 is from clean energy production incentive scheme and the renewable energy capacity development grant which is still not enough to justify emission reduction as seen from a relatively high

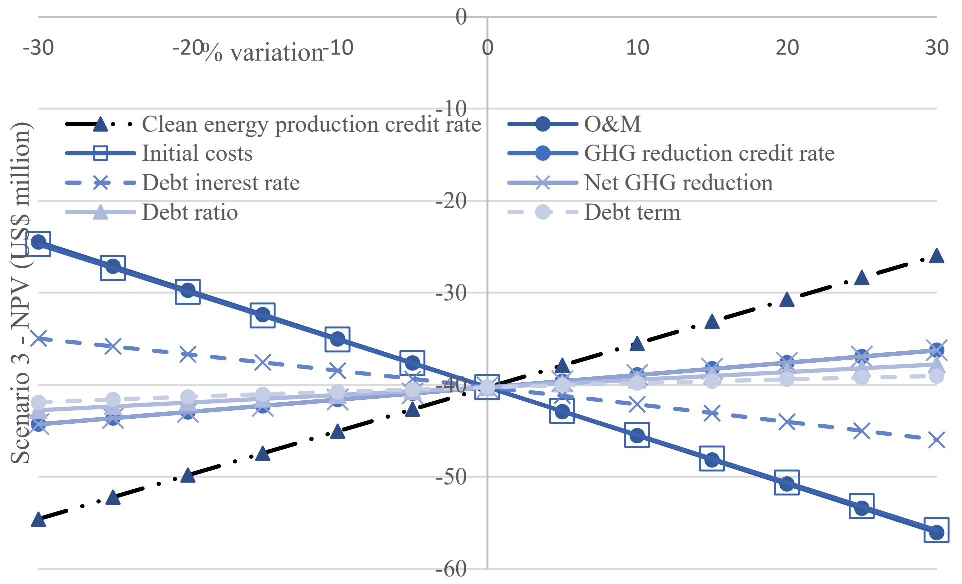
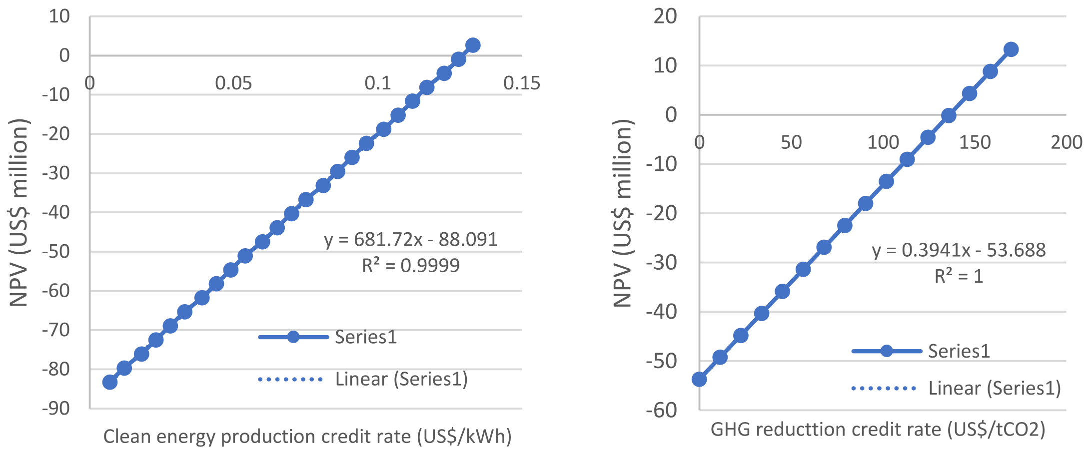


Fig. 10. Impact of different parameters on NPV in scenario 3.



(a)

(b)

Fig. 11. Scenario 3: (a) Sensitising clean energy production rate while keeping all the other parameters constant (b) Sensitising GHG reduction credit rate while keeping all other parameters constant.

positive value for cost of GHG emission reduction.

Comparison of simulated results using SAM

The validation of any modelling results is usually done with real data [28] but in this case, there is no existing geothermal power plant in Fiji. So, to check the correctness of the results System Advisor Model (SAM) software developed by National Renewable Energy Laboratory (NREL) was used to model the 10 MW binary GPP and compare its results with the results of RETScreen software. Ali et al., [94] validated their simulated results of HOMER using RETScreen software while carrying out a pre-feasibility study of roof-top mounted solar photovoltaics. Chennaif et al., [95] have used SAM to validate the Electric System Cascade Extended Analysis (ESCEA) results for concentrating solar power photovoltaic systems and wind turbine systems.

Results from SAM and RETScreen are shown in Table 8. There is a 1.3% difference in the annual energy output from RETScreen model compared to SAM while the NPV and EPC differences are 2.8% and 1.7% respectively. Hence, we find that both softwares give similar results.

Discussion

The estimated energy generated from the proposed 10 MW ORC GPP in the Northern Viti Levu of Fiji is 78.9 GWh. The advantages and benefits of Organic Rankine Cycle power plants in terms of their high reliability operation, reservoir sustainability, and environmental friendliness have been well demonstrated during more than twenty years of successful operation worldwide [96]. This has led the United States of America to have the largest installed ORC geothermal power plant capacity of around 750 MW, followed by Turkey and New Zealand [97]. They also report that by the end of 2016, the most prominent ORC units are ORMAT, which has 1,102 of installed units with a total installed capacity of 1,701 MW, followed by Turboden with 267 installed unit with a total capacity of 363 MW.

The geothermal energy produced from the proposed 10 MW GPP in this study could supply to the local loads at the area of interest. There are currently two loads in the area; one is the grid-connected electricity demand from residential and commercial customers and the second is the off-grid load of gold mine that has its own diesel generators. The

Table 8
Comparison of RETScreen results with SAM.

Parameters	RETScreeen	SAM	Absolute Difference	% Difference relative to SAM (=absolute Δx/x)
Input				
Temperature of geothermal fluid (°C)	160	160	0	0
Power capacity of binary GPP (MW)	10	10	0	0
Turbine efficiency (%)	82.5	82.5	0	0
Initial costs (US $/kW)	6000	6000	0	0
O&M costs (US $/kW-yr)	406	406	0	0
Inflation rate (%)	3.2	3.2	0	0
Discount rate (%)	10	10	0	0
Lifetime (years)	30	30	0	0
Electricity export price (US $/MWh)	162	162	0	0
Capacity factor (%)	90	90.1	0.1	0.11
Output				
Annual Energy Generated (GWh)	78.922	78.909	0.013	1.3
NPV (US$ million)	17.284	17.779	0.495	2.8
EPC (US$/MWh)	140	137.7	2.3	1.7

annual energy demand for the gold mine is approximately 85.3 GWh that is currently being supplied by its own IDO and HFO generators of total capacity 19 MW. Because the grid electricity demand for the area is not significant due to fewer residential customers in the area and small business centers, the proposed 10 MW GPP could meet 92.5% of the gold mine's electricity energy demand.

Currently, the gold mine meets 100% of its electricity demand by diesel generators that consume 22 million litres of diesel annually. Combusting this generate 72,200 $tCO_{2\text{-eq}}$ of GHG emissions that can be avoided if geothermal energy-based electricity is used to meet the demand of the gold mine. This initiative will support Fiji's LEDS and NCCP's objective 4.1 that states "To derive 100% of national electricity production from renewable energy sources by 2030 and achieve net-zero annual greenhouse-gas emissions by 2050" [98].

Barriers and strategies for GPP development in small island country

Geothermal technology will be new for Fiji as there are currently no GPP. Hence, the technical expertise present in the private and public sectors is lacking. However, to overcome this, extensive capacity-building needs to take place at different institutions. Fiji can learn from its neighbouring countries, especially New Zealand and Papua New Guinea that have GPP installed and have considerable experience in operating them. New Zealand has more than 60 years of experience in geothermal power plants and has total geothermal power plant installed capacity of 1.005 GW that supplies around 18% of New Zealand's electricity [99]. While Papua New Guinea started with a 6 MW GPP in 2001 that was installed in Lihir island by the Lihir Gold Limited that was later expanded to a total capacity of 56 MW by 2007 in steps of 30 W in 2005 and 20 MW in 2007 [100]. Fiji can learn from these countries how to start geothermal development and from New Zealand how to continue developing GPP capacity once one project has been commissioned.

Another barrier to geothermal energy development in Fiji is the uncertainty in licensing geothermal energy exploration. One of the main actors for geothermal resource identification is the Fiji Ministry of Lands and Mineral Resources. It has a MRD with a mining division that attracts private investment in resources, exploration and development through the provision of geoscientific information on mineral resources, management of an equitable and secure titles systems for the mining, petroleum and geothermal industrials [101]. It also regulates the extracting industries, ensures the sustainability of the environment, and provides a license for geothermal resource exploration. IRENA reports that MRD issues special prospector license to contractors however, there are times when no work is done by contractors and license lapses [49]. Therefore, IRENA recommends stricter screening during issuing of licenses so that licensees carry out the work after receiving a license.

The third barrier to GPP development, which is also present to other renewable energy-based electricity development, is the uncertainty in power purchase agreements and lack of attractive independent power producer (IPP) tariff (electricity export rate). Fiji needs to develop a portfolio of electricity export tariff rates based on the renewable energy resources used, type of technology used, cost of electricity generation and a decent mark up for the investors to make the project financially attractive. Fiji's minimum electricity export tariff is set at US$162.1/MWh. In section 4, it was found that the cost of electricity production for a 10 MW GPP is US$140/MWh. The project will not be financially viable if an electricity export tariff is offered at a lower value than US$140/MWh. Also, risk analysis revealed that there is a still a chance of having negative NPV at US$162/MWh of electricity export tariff, so to reduce the risk, GPP developers must seek a higher electricity export tariff. Hence, for negotiation purposes, any GPP developer would want an electricity export tariff rate more than the cost of electricity production, more than the minimum rate set by FCCC, reducing the risk of negative NPV.

The most important barrier of GPP is its high upfront capital cost besides the expensive exploration cost. The exploration is a financially risky exercise as it does not guarantee positive results. Hence, Eyudigan et al., [84] suggest choosing modular growth where investments can be recovered in a short time. ORC technology can be easily applied to a modular growth model that addresses high uncertainty of geothermal power investments until their production stage and reduces risks.

To reduce the risks for GPP investors, there can be a portfolio of incentives that the policy makers can promote. Zhao et al., [91] has identified and discussed four major incentive strategies that Chinese government has used to trigger rapid growth in renewable energy power generation: research and development incentives, fiscal and tax incentives, grid-connection and tariff incentives, and market development incentives. They have discussed the various incentives, grants, and taxes applicable to increasing electricity generation from renewable resources. They have reported that feed-in-tariff for geothermal power generation is determined by the actual construction and operation costs with reasonable profits. For geothermal market development, China provides support and encourages the establishment of research centres. Qadir et al., [102] have reviewed a range of incentive policies in different countries to promote renewable energy based electricity generation. They admit financing as the major hurdle to renewable energy uptake and recommend involving financial institutions to support investors willing to invest in RE and raising awareness on the costs of generation and operating RE projects.

Van Erdeweghe et al., [86] carried out an economic analysis for a low-temperature geothermal power plant and found that the NPV or the LCOE might be the most interesting performance indicator depending on the involved party. Hence, the discussion in this paragraph looks at the financial indicator of NPV to judge a project's value. The results section confirmed that the NPV of GPP projects is positive when incentives are given, making the project financially attractive. Scenario 1 had electricity export tariff provided as US$162.1/MWh and this led to NPV of US$17.284 million, while with additional incentives such as clean energy production incentive (US$0.07/kWh for the first 15 years of the project), renewable energy capacity development incentive (US$300/kW) and participating in emission trading scheme of US$34/$tCO_{2\text{-eq}}$ for 21 years in scenario 2 led to US$81.427 million of NPV. Hence, NPV in scenario 2 is 4.7 times more than NPV in scenario 1. However, in scenario 3, when the electricity export tariff is absent but other incentives (clean energy production incentive, RE capacity development incentive and participating in emission trading scheme) same as scenario 2, the NPV is negative (US$-40.289), indicating that if GPP developers want to invest in this technology and produce electricity to meet their own demand (such as that of a gold mine), then they need some additional incentives to make the investment worthwhile. Hence, carrying out sensitivity analysis for scenario 3, Fig. 11 showed that while keeping all other parameters constant and changing the clean energy production incentive rate, a minimum rate of US$130/MWh would lead to a positive NPV. In addition, while keeping all parameters constant and changing emission trading scheme rate, a rate of US$135/$tCO_{2\text{-eq}}$ lead to a positive NPV.

Emission trading system (ETS) is one of the well-known financial tools that countries could use to reach their Paris agreement commitments. ETS, also called the cap-and-trade system, allows low embittering nations to sell their extra allowances to larger emitters and thus creates a supply and demand for emission allowances [103]. This system effectively caps the total level of emissions. Fiji is new in carbon trading and, in January 2021 signed an emission reduction payment agreement with Forest Carbon Partnership Facility. This is a 5-year arrangement where periodic payment will be made based on the emission reduction quantification by increasing the forest area [104]. Fiji is also the first international partner to join Indo-Pacific Carbon Offsets Scheme established by Australia and this lays the foundation for a high integrity and accessible carbon market for Fiji [105].

Conclusions

Geothermal power plants can help reduce fossil fuel dependence of Fiji while being environmentally friendly. They can be built modularly to be more cost-effective. This paper attempted to make a case for a 10 MW organic Rankine cycle geothermal power plant development in Fiji. Modelling results show that 78.9 GWh of electricity can be generated that can avoid 39,461 $tCO_{2\text{-eq}}$ emission when the GHG emission factor for grid electricity generation is taken as 0.538$tCO_{2\text{-eq}}$/MWh of generation. To study the financial viability of the proposed GPP, three scenarios were studied.

Scenarios 1 and 2 are cases where electricity is exported to the grid while in scenario 3 electricity was not exported to the grid and instead used locally. It was found that when only electricity export tariff of US $162.1/MWh is offered to project developers (scenario 1), NPV of the project is US$17.285 million. This value increases by 4.7 times in scenario 2 when extra incentives such as clean energy production incentive, renewable energy capacity development incentive and emission trading system is offered to the developers. So, scenario 2 is better than scenario 1. When no electricity is exported to the grid in scenario 3, clean energy production incentive rate must be much higher (USD130/MWh) to give a positive NPV when compared to scenario 2 where the clean energy production incentive rate was taken as US$70/MWh.

Financing is not the only factor that has to be considered while developing GPP. Successfully developing GPP on an island with no experience or expertise in the technology will take a lot more effort ranging from building human and technical capacity to setting the right regulatory environment for investors to feel confident to invest in. There also needs capacity development in the public and private sectors. This study provides results that can benefit potential investors, funding agencies, government policy makers, and other key stakeholders when considering developing geothermal power as a viable electricity generation resource in Fiji.

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CRediT authorship contribution statement

Ravita D. Prasad: Methodology, Writing – original draft, Formal analysis. **Atul Raturi:** Conceptualization.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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