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Utilization of Geothermal Energy in the Parrylands Field for Electricity Production

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Abstract

Trinidad and Tobago (TT) was ranked as the second-highest emitter of carbon dioxide per capita in 2020. Similar to other Small Island Developing States (SIDS), TT is vulnerable to the negative effects of climate change and is also a signatory to the Paris Agreement. The use of renewable energy especially Enhanced Geothermal Systems (EGS) is receiving much attention in many parts of the world today. Therefore, this study seeks to evaluate the possible use of EGS for electricity production by using abandoned oil and gas reservoirs in the Parrylands field located in southern TT. This study confirmed that abandoned oil and gas reservoirs in the Parrylands field in TT could utilize EGS for electricity production and CO_2 *emissions reduction. A simulation model was built using CMG and the model was used to quantify the optimal amount of energy that can be produced. It also demonstrated that the cumulative enthalpy produced was higher using three-spot and five-spot configurations as well as by replacing water with* CO_2 *as the geothermal fluid. The results showed that the optimal cumulative enthalpy was* 6.1×10^{10} *Btu translating into a binary plant size of 0.1 MW capacity, which can be used to power approximately one hundred homes within the plant's vicinity. By utilizing the subsidized electricity cost of US$ 0.05 per kWh, the economic analysis found an Internal Rate of Return (IRR) of 11% and a positive Net Present Value (NPV) value. Additionally, when compared to a natural gas-fired plant, the* CO_2 *emissions reduction potential was found to be 15,100 tons over a project lifetime of twenty years. This study clearly demonstrates the significant potential that EGS can provide when used for electricity generation by utilizing abandoned oil and gas reservoirs at the Parrylands field location.*

Keywords
Enhanced geothermal systems; Climate change; Renewable energy; Economic evaluation

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1 Introduction

The energy demand globally is expected to rise by a significant value of 47% over the course of the next thirty years. This is in large part due to the increase in population and energy demand, particularly in developing Asian countries[1]. Consequently, the demand for fossil fuels will also rise, leading to the knock-on effect of increasing global carbon emissions (Figure 1).

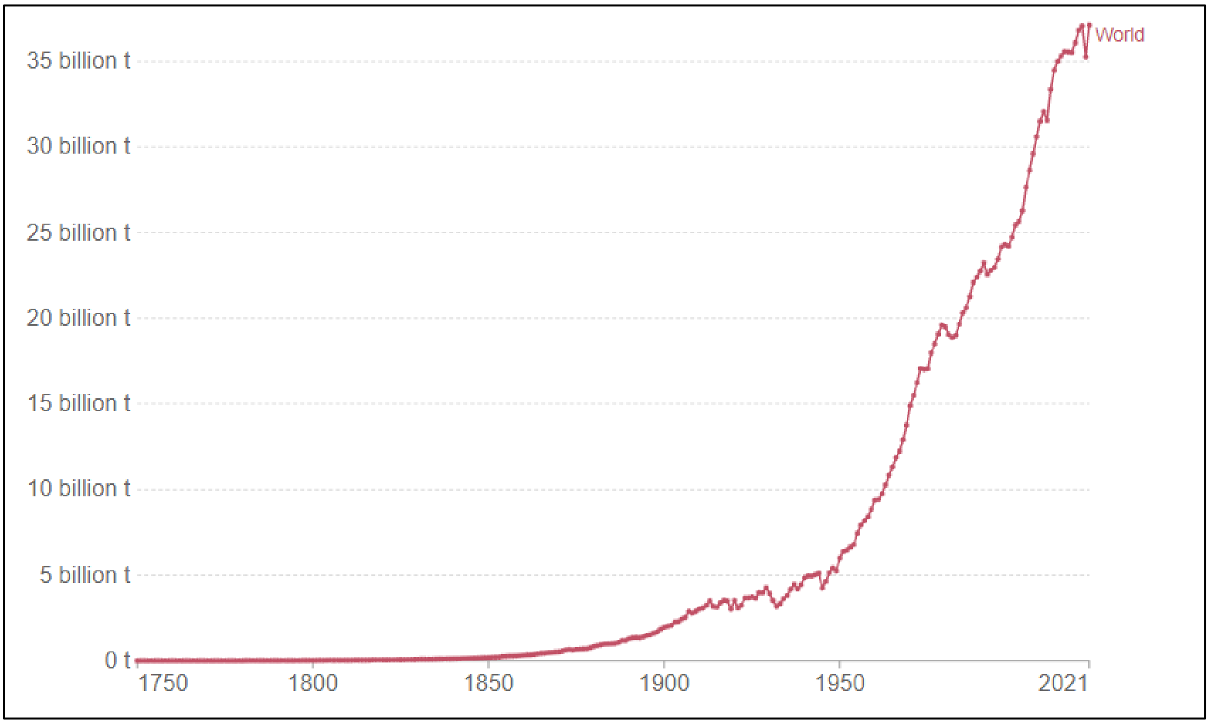


Figure 1. Global CO_2 emissions for fossil fuels and industry[2].

Trinidad and Tobago (TT) like many Small Island Developing States (SIDS) is especially vulnerable to the adverse effects of climate change. In 2020, TT was ranked as the second-highest emitter of carbon dioxide per capita worldwide as per the World Bank data for 2018[3]. TT has a high dependency on the oil and natural gas sector which accounting for 85 percent of total export earnings, 40 percent of government revenue, and over 35 percent of Gross Domestic Value, which is affected by depleting resources[4]. The global energy crisis enhanced global warming and environmental pollution have developed into the main drivers in selecting of energy sources with renewables becoming increasingly popular[5]. In keeping with the Paris Agreement[6], TT needs to investigate the potential use of other cleaner energy sources consistent with strategic decisions and policies adopted by other countries around the world[7-13].

Renewable energy strategies, including Enhanced Geothermal Systems (EGS) can form a big part of TT's greenhouse gas (GHG) emissions reduction drive. In the Caribbean, geothermal energy is currently utilized mainly in the lesser Antilles due to their natural geothermal reservoir systems. However, EGS can still be applied in TT by utilizing abandoned oil and gas reservoirs and reservoirs close to existing mud volcanoes[14]. According to published statistics, there was a total of 15 GW equivalent of global installed geothermal energy capacity in 2020[15].

The use of EGS has been receiving much attention as it applies to the sections of a geothermal reservoir. In these sections, energy production can be obtained or enhanced via mechanical, thermal, or chemical methods of stimulation[16,17]. As outlined by Patihk et al.[14] and Bell-Eversley et al.[18], a geothermal reservoir's temperature not only determines the overall thermal potential of a geothermal reservoir, but also directly impacts the choice of the power plant that can produce electrical energy. According to data produced by the International Renewable Energy Agency (IRENA)[19], the electrical energy output efficiency of a binary power plant reduces significantly below a fluid temperature of 100°C. This will apply to abandoned wells and depleted reservoirs in TT.

The most crucial step for determining the suitability of a field for geothermal energy production involves the geological description of the reservoir area. This includes calculating thermal resource area and evaluating of geologic characteristics and reservoir location in order to determine the total thermal energy available as well as the recoverable thermal energy[20]. As demonstrated by Patihk et al.[14] and Bell-Eversley et al.[18], the probabilistic method to determine the recoverable thermal energy has been successful and involves utilizing Monte Carlo simulations to determine the most likely temperature, rock density and porosity values. The commercial reservoir simulation software package known as CMG (Computer Modelling Group) has been used by researchers to develop the simulation model of the geothermal system[14,18,21]. The process involved digitizing structure and oil sand isopach maps using well log data. Based on research done by Asai et al.[22], CMG was also utilized to develop the model and to optimize the effect of injection/production flow-rate schemes on the rate of geothermal heat production from a reservoir, using a single producer and injector well combination (doublet model). Asai et al.[23] also investigated the efficient workflow for an EGS simulation with CMG for the determination of the optimum grid size and well and/or fracture spacing. Additionally, Chong et al.[21] demonstrated that the energy extracted from a geothermal resource is affected by varying the producer/injector well configurations. This is done by simulating two- and five-well configurations in a previously built geologic model. Parameters such as the surface and bottom-hole temperatures of the water as well as the energy produced were analyzed to determine the optimum configuration. To add, the influence of well configuration on geothermal energy production was also demonstrated by Sanyal and Butler[24].

In another study, the use of carbon dioxide instead of water as a geothermal fluid for an EGS was thoroughly investigated by Pruess[25] and Liu et al.[26], who conducted simulation models to evaluate the heat extraction and mass flow rates for a hypothetical reservoir.

Previous studies have also found that abandoned oil and gas reservoirs for EGS electricity production were economically feasible with a rate of return of greater than 10%. This is because, among other things, a large percentage of the costs for an EGS system lies in the well drilling costs[14,18]. Economic analysis involved calculating capital expenditure (CAPEX), operating expenditure (OPEX), and the net cash flow for the project. Economic indicators such as the internal rate of return (IRR) were calculated with a minimum acceptable rate of return (MARR) of 10% used for projects.

This project seeks to evaluate the utilization of EGS for electricity production for the previously unstudied Parrylands field located in southern Trinidad, by utilizing a simulation model built in CMG. The model was analysed to quantify the optimal amount of energy that can be produced. Sensitivity analyses were also performed to investigate the effect of varying well configurations on the energy produced as well as the use of CO_2 as the geothermal fluid instead of water. The carbon dioxide emissions reduction potential for the project and the economic viability of the optimal model were also evaluated.

2 Methodology

The methodology utilized for this study is shown in Figure 2.

The first step involved obtaining the geological description of the reservoir area using well log data from the field, including the structure map, permeability and porosity[27]. The simulation model was then built using the data gathered. Natural fracture modelling was utilized to develop the non-single porosity, homogenous model as outlined by Bell-Eversley et al.[18]. In the third step, the sensitivity analyses were performed by varying specific parameters in the numerical model. Well configuration and patterns (doublet, triplet and five-spot) were simulated in the software as previously described by Sanyal and Butler[24]. The use of CO_2 as the geothermal fluid was investigated by varying the fluid properties in the CMG software to match those of carbon dioxide[26].

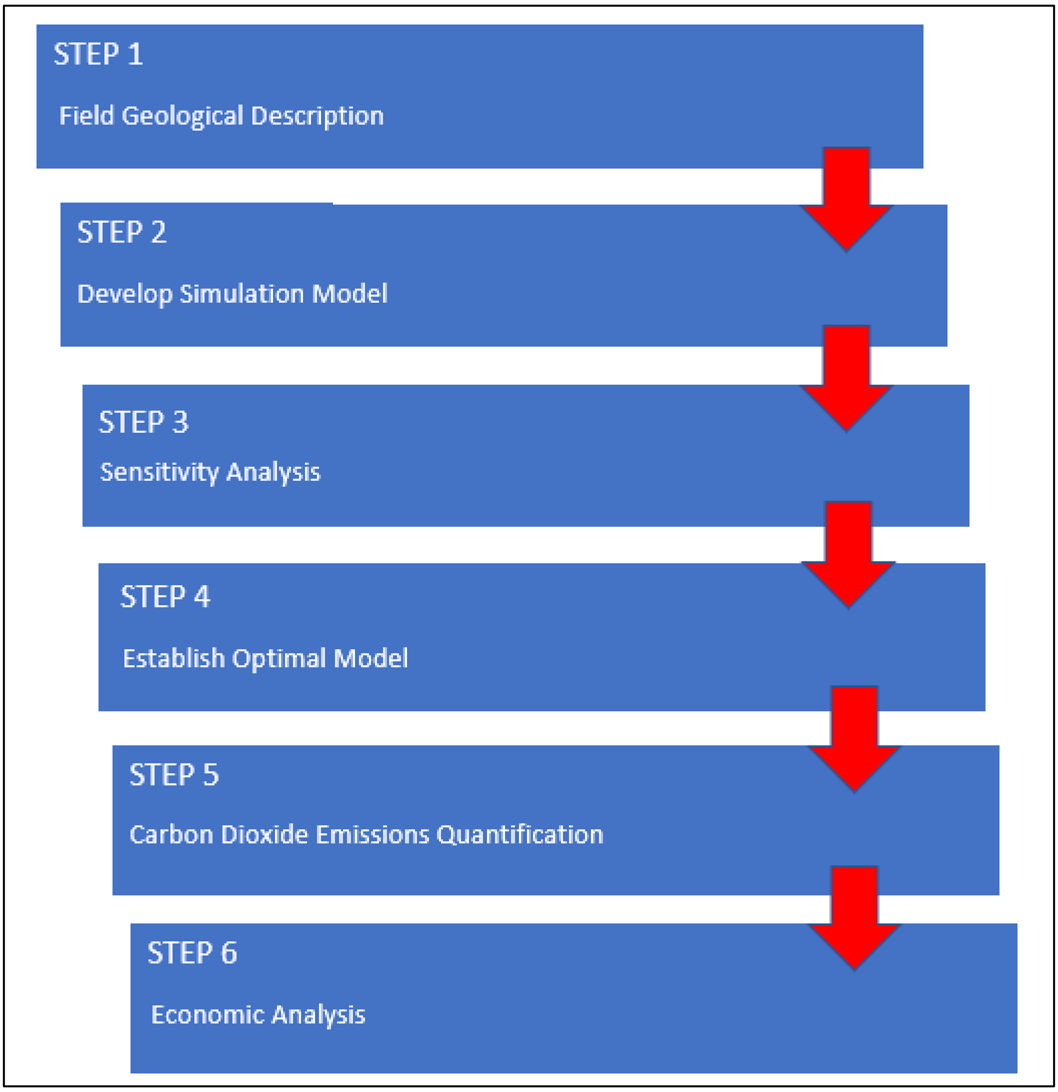


Figure 2. Methodology flowchart for study.

After completing all the sensitivities, the optimal model was determined by selecting the strategy associated with the maximum energy produced in Step 4. The optimal model was utilized to determine the carbon dioxide emissions related to the strategy using standard emission factors for both natural gas and geothermal power plants as specified by Bloomfield and Moore[28]. The total emission value was obtained by multiplying the total energy production in kWh with the emission factors and the carbon dioxide reduction potential was determined. In the final step, the economic analysis was conducted as described by Bell-Eversley et al.[18]. CAPEX and OPEX were determined, and revenue was then calculated by utilizing prices from an electric bill from the Trinidad and Tobago Electricity Commission. Using these above values, the IRR and NPV were calculated to determine the economic feasibility of the project. An IRR of greater than 10% and a positive NPV value were used as the threshold for determining feasibility.

3 Results and Discussion

3.1 Field Description

The field utilized in this study is the Parrylands field located in southern Trinidad which currently occupies hundreds of abandoned wells (Figure 3). The reservoir in this area is made up of sands from the Cruse formation. This formation contains silt stones, claystones and sandstones which are late Miocene to early Pliocene in age. The Cruse formation is further delineated into the Upper and Lower Cruse formations[29]. It should be noted here that this particular field was subjected to steam flooding during its hydrocarbon-production lifetime.

Figure 3. Parrylands field location in Trinidad[18].

The Cruse sandstones in the reservoir are covered by the Lower Forest clay which consists of a deltaic plain depositional environment. Figure 4 shows the log data obtained for this field which was utilized in developing the numerical model in CMG. The structure map obtained from a previous study[27] for this reservoir (Figure 5) was digitized in Didger prior to import into CMG to develop the numerical model.

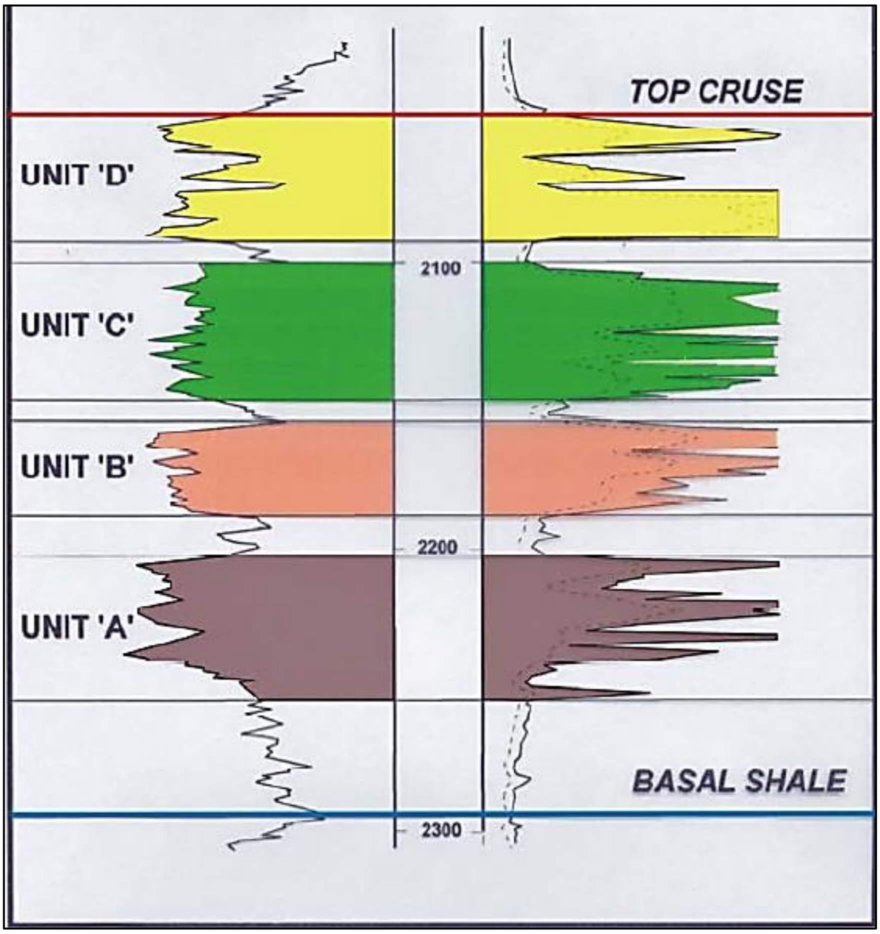


Figure 4. Well log data for the Cruse Sands[27].

3.2 Modelling results

CMG was utilized to develop a 3D numerical model of the geothermal reservoir system. In developing the geothermal model, the net sand isopach map was digitized using the Didger software. This was then imported into CMG and a 3D view of the final grid constructed is shown in Figure 6. The geothermal reservoir parameters used to build the model are shown in Table 1.

Table 1. Geothermal reservoir parameters utilized in model[27].

Parameter	Value
Depth to top of sand	2,050 ft
Permeability	265 mD
Porosity	31%
Sand thickness	75 ft

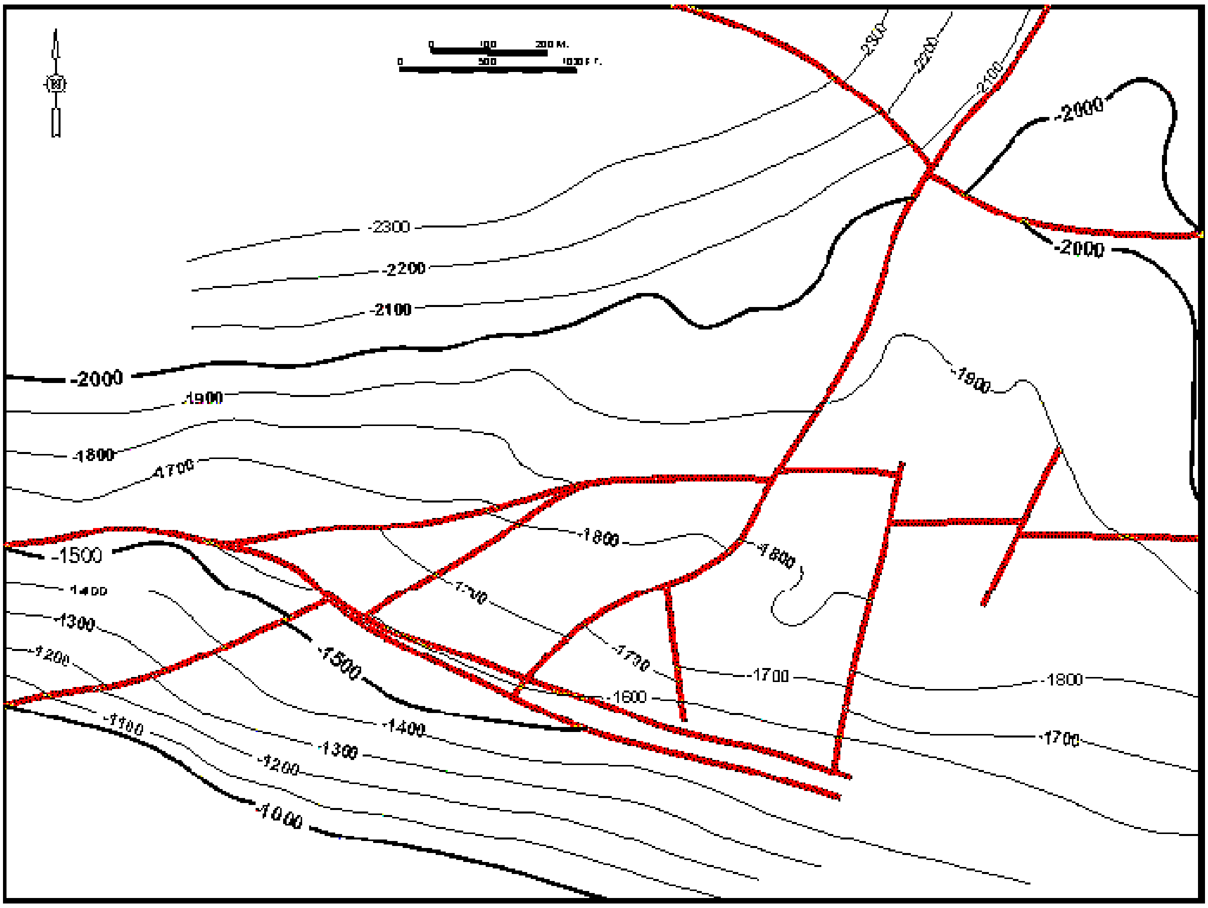
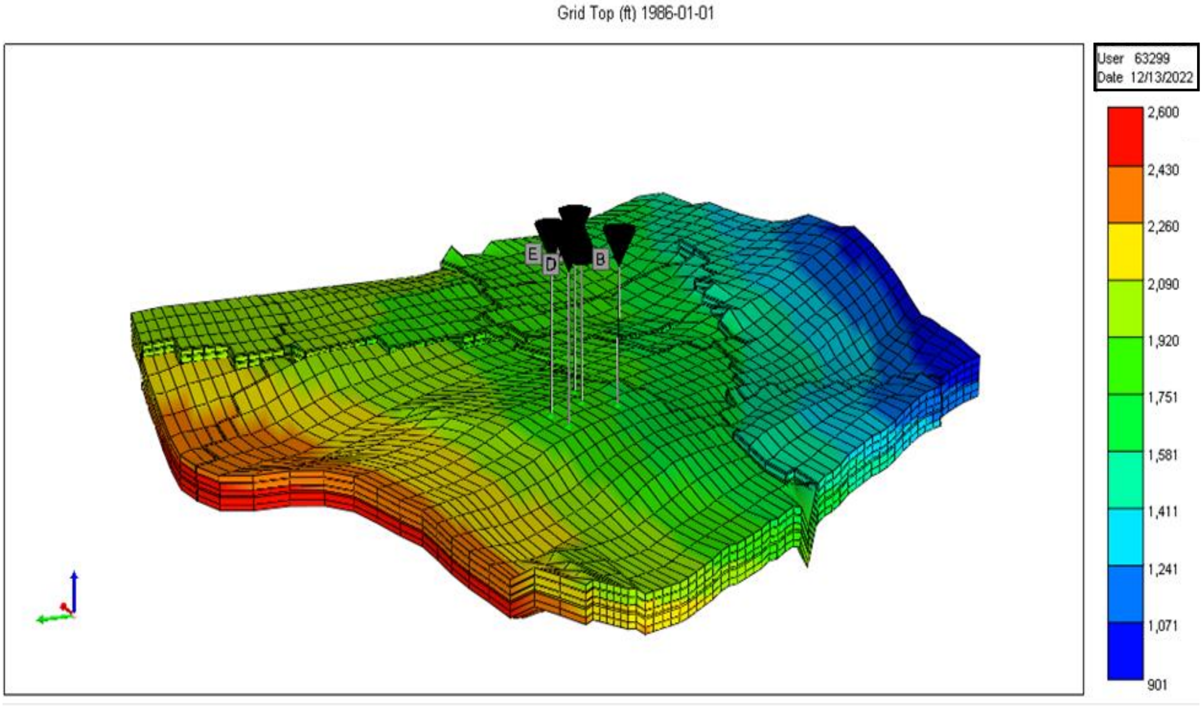


Figure 5. Cruse structure map[27].



Note: The five wells used in this study were labelled A-E and are shown at the pin locations in the figure.

Figure 6. 3D view of constructed grid in CMG.

Additional data used for the model input is shown in Table 2. The thermal properties shown apply to sandstone reservoirs that match the environment of the Parrylands field.

Table 2. Additional data used in the Geothermal model[18].

Parameters	Value	Unit
Temperature	212	°F
Rock compressibility	3.04×10^{-6}	psi^{-1}
Reservoir pressure	953	psi
Volumetric heat capacity	37.28	Btu ft^{-3} $°F^{-1}$)
Thermal conductivity of rock	48.57	Btu ft^{-1} day^{-1} $°F^{-1}$
Thermal conductivity of water	8.33	Btu ft^{-1} day^{-1} $°F^{-1}$
Liquid compressibility	5.00×10^{-6}	psi^{-1}
Molar density	3.46	lb mol ft^{-1}
Molecular weight	18.02	lb $lb\text{-}mol^{-1}$

The base model was constructed in CMG and utilized a well pattern with a single injector and a single producer. After completion of the simulator run, the cumulative enthalpy produced over the project lifetime of twenty years was found to be 8.2×10^9 Btu. This will be used as the baseline to compare the results from sensitivity analyses.

The effect of the adjustment of the well pattern configuration on the performance of the model was investigated. Initially, the base model was adjusted to a three-spot configuration with two injectors and a single producer. The cumulative enthalpy over the lifetime of the project for this sensitivity was a value of 8.6×10^9 Btu. This shows a small percentage increase in the total enthalpy when using a three-spot configuration when being compared to the base model.

The well pattern configuration was then adjusted to a five-spot configuration with four injectors and a single producer with all other variables remaining constant. The cumulative enthalpy over the lifetime of the project for this sensitivity was 9.2×10^9 Btu. This shows a small percentage increase in the total enthalpy when compared to the three-spot configuration. The results demonstrated that a change in the well pattern configuration impacted the total thermal energy recovered during the project, with the five-spot configuration having the most significant thermal energy recovery. The results of this sensitivity analysis are shown in Figure 7.

The performance of carbon dioxide as the geothermal working fluid instead of water was studied using a well pattern configuration of a single injector and producer. The results showed that using CO_2 resulted in an increase in the cumulative enthalpy over the project period, thus supporting the outcomes of previous studies done by Pruess[25] and Liu et al.[26] (Figure 8). They also found that the thermal extraction rate for carbon dioxide was higher than water for the same producer and injector well pressures. In terms of fluid chemistry, CO_2 is a weaker solvent than water against rock minerals with less tendency for dissolution of the rock minerals. Carbon dioxide also has a much larger compressibility and expansivity compared to water, implying less power is required for the pumps to maintain circulation. Carbon dioxide has a lower viscosity than water and thus flows easier in the reservoir and within fractured reservoirs. If CO_2 fluid losses occur, it can be considered as an added benefit in the form of sequestration.

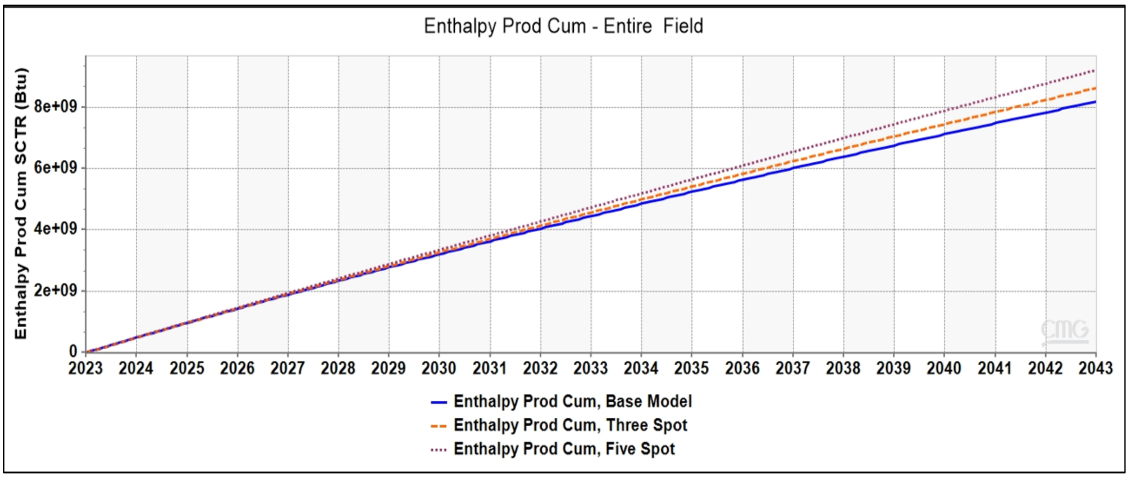


Figure 7. Well configuration sensitivity analysis.

The final value for the cumulative enthalpy was 6.1 × 10^{10} Btu, representing an increase in the total enthalpy produced throughout the project lifetime. This is approximately seven times the value obtained using the base model.

It is worthy to note that according to a previous study by Pruess[25], the thermal extraction rate for carbon dioxide can only be higher than water for the same producer and injector well if the reservoir pressure exceeds a critical value of ~1070 psi. However, for this reservoir, the pressure used in the geothermal model (Table 2) is 953 psi, which is below the critical value. This is due to the fact that the study by Pruess[25] only shows the results for a pressure of 653 psi in the subcritical scenario. In this case, the pressure is 953 psi. Additionally, the temperature is lower in this reservoir which would reduce the heat energy production when utilizing water. This is because much of the pressure differential is used in trying to overcome the greater viscosity of water at a lower temperature.

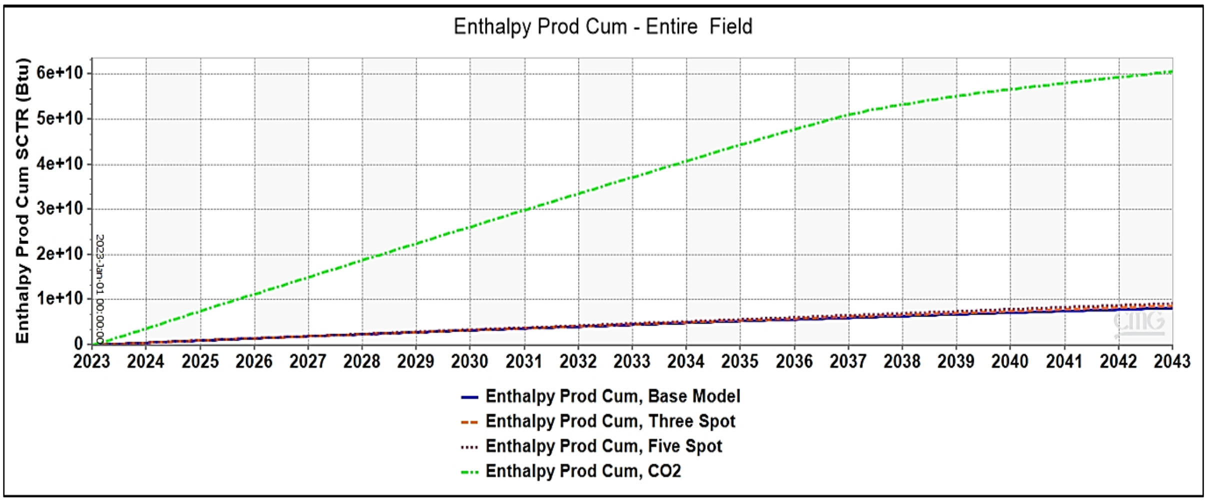


Figure 8. Cumulative enthalpy comparison results.

3.3 Carbon Dioxide Quantification

The results of the CO_2 emissions are shown in Table 3 and are derived using multiplicative factors. The rate of produced carbon dioxide for a natural gas plant is 1.03 lbs kWh^{-1} while for a geothermal Binary open loop cycle plant is 0.18 lbs kWh^{-1} as found in the literature[28]. The cumulative enthalpy produced (in Btu) over the twenty-year life cycle of the project was approximately 18,300 tons of produced carbon dioxide for the natural gas-fired plant, which is significantly higher than the geothermal plant that produced approximately 3,200 tons of carbon dioxide (about 15,100 tons of more carbon dioxide).

In terms of CO_2 emissions, the potential for carbon leakage from the downhole reservoir also needs to be addressed. The significant risks associated with this are the contamination of local aquifers as well as threats to animals and humans living in the vicinity of the site. In order to combat this, a risk assessment should be done to outline all the risks and mitigation plans required for the entire project life cycle. CO_2 monitoring stations should also be installed as part of the overall project.

Table 3. Carbon dioxide emission quantification.

	Carbon dioxide emissions	
	Emission factors- lbs per kWh	Carbon dioxide produced per tons
Natural gas	1.03	18,295
Geothermal	0.18	3,197

3.4 Installed Plant Capacity

The calculations show the steps to determine the installed plant capacity utilizing the maximum cumulative enthalpy produced over the twenty-year lifecycle of the project. Geothermal power plants worldwide generally have plant capacity factors that is greater than 90%[30]. In this project, a plant factor at the lower end of the scale at 90% was utilized.

- Cumulative enthalpy after twenty years = 6.1×10^{10} Btu
- Enthalpy conversion to Joules = $6.1 \times 10^{10} \times 1{,}055 = 6.4 \times 10^{13}$ J
- Conversion to Mega Joules = 6.4×10^{7} MJ
- Plant life conversion to seconds = $20 \times 365 \times 24 \times 3600$ = 630,720,000 s
- Joules converted to Watts = 6.4×10^{13} J / 630,720,000 = 101,376 W
- Plant size = $101{,}376 \times 0.9$ = 91,239 W

The plant size for this project is approximately 0.1 MW. While this is on the smaller end of the scale regarding plant capacity, it should be noted that there are comparable geothermal plants installed globally, such as in Taiwan (0.3 MW) and Thailand (0.3 MW)[31]. According to data from 2021, the average household uses approximately 1000 W of power[32], indicating that this plant can power approximately one hundred homes in its environs.

3.5 Economic Analysis

The economic assessment was performed using the data from the twenty-year production profile shown in Table 4.

Table 4. Economic parameters.

Year	Production/Btu	Production/kWh	Price/US$	OPEX/US$	CAPEX/US$
2023			0.05		320,000
2024	3,652,206,848	1,070,356	0.05	10,704	-
2025	3,821,816,576	1,120,064	0.05	11,201	-
2026	3,776,802,816	1,106,871	0.05	11,069	-
2027	3,761,091,584	1,102,267	0.05	11,023	-
2028	3,749,079,040	1,098,746	0.05	10,987	-
2029	3,733,819,392	1,094,274	0.05	10,943	-
2030	3,713,359,872	1,088,278	0.05	10,883	-
2031	3,681,599,488	1,078,970	0.05	10,790	-
2032	3,664,263,168	1,073,889	0.05	10,739	-
2033	3,636,035,584	1,065,617	0.05	10,656	-
2034	3,610,759,168	1,058,209	0.05	10,582	-
2035	3,567,599,616	1,045,560	0.05	10,456	-
2036	3,434,168,320	1,006,455	0.05	10,065	-
2037	3,227,398,144	945,857	0.05	9,459	-
2038	2,286,575,616	670,129	0.05	6,701	-
2039	1,847,099,392	541,331	0.05	5,413	-
2040	1,522,872,320	446,310	0.05	4,463	-
2041	1,364,172,800	399,799	0.05	3,998	-
2042	1,299,988,480	380,989	0.05	3,810	-
2043	1,255,993,344	368,095	0.05	3,681	-
Total	60,606,701,568	17,762,067		177,621	320,000

The electricity price used for calculations was US$ 0.05 per kWh[33] which is the subsidized electricity cost in TT. The OPEX values shown in Table 4 were calculated by using a factor of US$ 0.01 per kWh[34]. This covers the recurring costs to run the geothermal plant and would refer to expenses such as employee salaries as well as maintenance and repair costs. The CAPEX cost for the construction of a geothermal plant varies in the range of US$ 2 to 7M per MW of installed capacity[14]. Using the high end of the range at US$ 7M per MW of installed capacity, a CAPEX value of US$ 640,000 was calculated for this project. Since no drilling work is planned in this case, the CAPEX utilized for this project is estimated to be half of this calculated value at US$ 320,000.

The annual cash inflows and outflows were then calculated. Cash inflows were computed by multiplying the production values and the electricity price while the outflows were either the CAPEX or OPEX values shown in Table 5.

Finally, the Net Present Value (NPV) and the Internal Rate of Return (IRR) were calculated to determine the profitability of the overall project. For this project, a minimum rate of return of 10% was utilized in the calculations (Table 6). Since the NPV is a positive value and the IRR is greater than 10%, this indicates the overall feasibility of the project.

It should be noted, however, that in order to increase the profitability of the project, a discussion with the government is required in order to seek suitable financial incentives.

Table 5. Project cash flows.

Year	Cash inflow	Cash outflow	Net cashflow
2023	0	320,000	–320,000
2024	53,518	10,704	42,814
2025	56,003	11,201	44,803
2026	55,344	11,069	44,275
2027	55,113	11,023	44,091
2028	54,937	10,987	43,950
2029	54,714	10,943	43,771
2030	54,414	10,883	43,531
2031	53,949	10,790	43,159
2032	53,694	10,739	42,956
2033	53,281	10,656	42,625
2034	52,910	10,582	42,328
2035	52,278	10,456	41,822
2036	50,323	10,065	40,258
2037	47,293	9,459	37,834
2038	33,506	6,701	26,805
2039	27,067	5,413	21,653
2040	22,315	4,463	17,852
2041	19,990	3,998	15,992
2042	19,049	3,810	15,240
2043	18,405	3,681	14,724
Total	888,103	497,621	390,483

Table 6. Discount rate, NPV and IRR from the economic analysis.

Discount Rate	10%
NPV	20,452
IRR	11%

4 Conclusion

This study confirmed that abandoned oil and gas reservoirs in the Parrylands field in TT can utilize EGS for electricity production and CO_2 emissions reduction. A simulation model was built in CMG and the model was used to quantify the optimal amount of energy that can be produced. It was found that there is an increase in the cumulative enthalpy produced in the cases of using three-spot and five-spot configurations, as well as by replacing water with CO_2 as the geothermal fluid. The results showed that the optimal model's cumulative enthalpy was 6.1×10^{10} Btu. This gives a binary plant size of 0.1 MW, which could power approximately one hundred homes located within the plant's vicinity. By utilizing the subsidized electricity cost of US$ 0.05 per kWh, the economic analysis found an IRR of 11% and a positive NPV value. Additionally, when compared to a natural gas-fired plant, the CO_2 emissions reduction potential was calculated to be 15,100 tons over a project lifetime of twenty years.

Conflict of Interest

The authors declare that there was no conflict of interests.

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Author Contribution

Conceptualization: Alexander, D., Boodlal, D., & Maharaj, R.
Data curation: Lessey, K., & Alexander, D.
Methodology: Lessey, K., & Alexander, D.
Formal analysis: Lessey, K.
Visualisation: Lessey, K.
Software: Computer Modelling Group (CMG)
Writing (original draft): Lessey, K.
Writing (review and editing): Maharaj, R., & Boodlal, D.
Supervision: Alexander, D., Boodlal, D., & Maharaj, R.
Funding acquisition: Not applicable
Project administration: Lessey, K.

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