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The Potential of Geothermal Energy Combined with Carbon Capture and Storage in Trinidad and Tobago

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Abstract
Even without volcanic formations, Trinidad and Tobago can harness geothermal energy from depleted oil reservoirs with the additional benefit of storing Carbon Dioxide (CO_2) in them. This paper evaluates the combination of CCS technology with geothermal energy production utilizing CO_2 as the working fluid using the EOR 4 depleted oil well in the Forest Reserve Field in South-Western Trinidad. A reservoir model was created using CMG to test the reservoir's geothermal viability and CO_2 storage capacity. CO_2 storage was done using hysteresis and solubility in water since it would not be trapped while being returned to the surface for energy production. The base model constructed was optimized for maximum energy production using a CMOST sensitivity analysis varying specific parameters (matrix porosity, matrix permeability, fracture spacing, rock permeability, thermal conductivity, heat capacity). The optimal dual permeability model had a well spacing of 400 m with an injection pressure of 20,000 kPa. The CO_2 model had a production rate of 1.87×10^6 kg per day and produced 1.997×10^{16} J of energy, whereas the H_2O (water) model had a production rate of 1×10^7 kg per day and produced 8.475×10^{15} J of energy. The amount of CO_2 stored was 4.7004×10^7 kg. The total CO_2 reduction was 1.984×10^9 kg compared to using Natural Gas. The sensitivity analysis showed fracture spacing had the largest impact, increasing enthalpy produced from 7.2×10^{14} J to 1.57×10^{15} J. The plant would effectively cost US$ 1,061.24 per kW, which is superior in cost efficiency. This study demonstrated the enormous potential for using CO_2 as the working fluid for geothermal power generation in abandoned oil wells such as EOR 4 and offers a low-carbon energy generation strategy associated with a carbon emission reduction technology.

Keywords
Climate change; Geothermal systems; Carbon capture; Emission reduction

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1 Introduction

Hydrocarbons from fossil fuels have led to severe environmental, ecological and climatic problems. The utilization of low-carbon energy and carbon emission reduction technologies are crucial strategies for sustainable development.

Geothermal energy has been receiving global attention as a source of clean and renewable energy[1,2]. Geothermal energy is a form of energy that comes from beneath the earth's surface as a result of heat flow due to naturally occurring radioisotopes, which have half-life periods numbering in millions to billions of years[3]. This means that this energy source can be harvested indefinitely[4]. The geothermal gradient is the increase in temperature per unit depth when going into the Earth's crust and is approximated as 25-30 °C km^{-1} but is much higher in regions near volcanoes and tectonic plate activity[5]. Compared to other renewable energy sources, geothermal energy has the advantages of high stability, high utilization rate, higher safety, low operating costs and comprehensive utilization[4,6].

Carbon capture and storage (CCS) is a strategy used to reduce the amount of carbon dioxide (CO_2) in the atmosphere by storing it deep underground in suitable geological formations. CCS has been shown to reduce CO_2 emissions via technologies such as chemical absorption, polymer membrane separation, porous material adsorption, and chemical looping separation[7]. Once captured, the CO_2 can be stored via deep-ocean storage, mineralized storage, depleted oil or gas field storage, and saline storage[8]. The inaugural CCS project was demonstrated at the Norwegian Sleipner field in the North Sea, whereby 1 million CO_2 tons per year has been stored since 1996 at approximately 1 km depth. Technological advancements have evolved in the areas of storage efficiency, monitoring, geochemical properties, capillary trapping, and the interfaces between plumes and water[9].

CO_2 produced from sources such as industrial and power plants can be captured directly and transported for sequestration. For this to occur properly, the site must be deep enough for the CO_2 to remain in the supercritical state, there must exist a low permeability seal around it (such as caprock) to prevent leakage, there must be a large storage volume and a large permeability for the CO_2 to be injected at reasonable rates[10]. Saline aquifers are also considered a favourable site for CCS where the CO_2 undergoes multiple forms of trapping to safely store the gas[11]. Since the CO_2 is less dense than the saltwater in the aquifer, it rises, making it very important for the aquifer to be properly sealed at the top for proper storage. In order to significantly reduce the amount of CO_2 emissions, the amount of gas stored globally needs to reach 40 $MtCO_2$ per year[9].

Although the concept of combining CCS and geothermal energy has been previously utilized in reservoir engineering, the coupling of CCS with geothermal power facilities is relatively new. It involves using CO_2 as the circulation fluid which passes through the reservoir to extract heat energy, resulting in an overall reduction of CO_2 emissions and cost efficiency compared to conventional processes[12,13]. Conventional enhanced geothermal system (EGS) facilities require significant make-up water. In contrast, the combined CCS-EGS plant uses CO_2 in a supercritical state instead of the water and allows for the CO_2 to be stored permanently. Additionally, the efficiency of CO_2 as the heat extraction fluid is greater than the water (brine). This CCS-EGS combination can help to reduce cost and land space since the site of injection is shared, and by using CO_2 as the geothermal fluid, no water needs to be used and the cost of pumping will be reduced since CO_2 is less dense. CO_2's fluid and thermodynamic properties also show that it is better than water for heat energy transfer[12]. While the supercritical CO_2 is being injected, some of it will be stored while some, when acquiring heat from inside the injection well, will return to the surface for energy production[9]. One major barrier to CCS is its overall cost but combining it with EGS will make it more economically viable. The energy produced will not only generate income, but can also be used to power the CO_2 injection pumps, making the plant self-sufficient. The CCS-EGS combination process generally involves the CO_2 being injected and heated underground and with a small amount being recycled to the surface through pipes and into the geothermal plant. The plant using a heat exchanger will transfer the heat to another working fluid which is used to generate electricity. The CO_2 then returns below the surface and into the well; over time, the CO_2 in the well is stored permanently[14]. A simplified schematic of a CCS/Geothermal Combined Facility is shown in Figure 1.

In enhanced geothermal systems (EGS), the overall heat production has been shown to be around 50% higher using CO_2 over water due to the CO_2 having a higher density-to-viscosity ratio[15]. The lower viscosity of CO_2 also results in the ability to use higher flow velocities during injection and production. CO_2 being more compressible or expandable than water would also result in the geothermal plant requiring less energy to run at a similar production capacity if it is using water[16]. CO_2 also has the added advantage of being a poor solvent for many minerals in rock, unlike water, making the system even more economically viable[17]. The heat extraction in lower temperature geothermal reservoirs such as abandoned oil wells using this strategy has been proven successful[12].

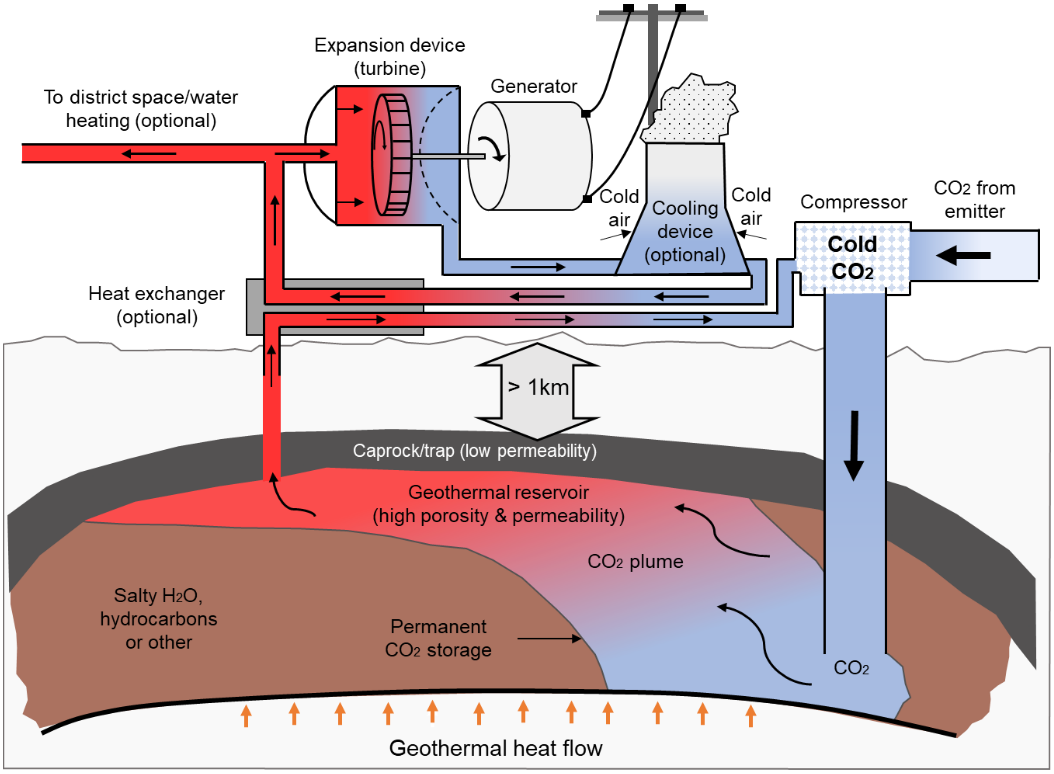

Figure 1. A simplified schematic of a CCS or Geothermal Combined Facility.

Trinidad and Tobago (TT), like other small island developing states (SIDS), has been experiencing the negative impacts of global warming and climate change. TT's economy has been heavily dependent on hydrocarbons and is currently exploring options to reduce its emissions, diversify its energy sources and move towards renewable energy generation[4]. TT currently has one of the lowest prices in electricity at a consumption rate of US$ 0.04 per kWh with the unsubsidised price being US$ 0.12 per kWh[18]. Like many other Caribbean countries, TT has started the transition to renewable energy systems and has begun implementing policies such as subsidy removal for energy harnessed from renewable sources to become economically viable[19].

Renewable energy in the form of geothermal energy usually comes from below the Earth's surface, usually near volcanic formations. Although TT lacks these volcanic formations, there are abandoned oil and gas wells in the Forest Reserve fields in southern Trinidad which have a high enough geothermal gradient to facilitate energy production[20]. Recent studies demonstrated the feasibility of using local oil wells in south TT for geothermal energy[18,21]. These studies also highlighted the dependence of total energy produced from geothermal sources on well-spacing and the need for optimization of the distances between injection and production wells. There is documentation which supports that by reusing these wells, the need for deep drilling is eliminated and the cost is reduced since the wells were previously drilled[22].

There exists the additional benefit that these abandoned wells may be suitable for CCS since their characteristics satisfies the requirements of being made up of permeable sandstone layers in the subsoil in a depth range from approximately 1,000 to 3,000 m[23]. The results and data from a previous study demonstrated that CCS is an ideal candidate for consideration in TT for the removal of CO_2 [24].

The purpose of this paper is to evaluate the viability of combining CCS technology with geothermal energy production using the EOR 4 depleted oil well in the Forest Reserve Field in South-Western Trinidad.

2 Methodology

The methodology involved identifying a suitable reservoir using location and reservoir properties. A model was developed for CO_2 Plume Geothermal (CPG) and the energy generated per unit of CO_2 gas was calculated[14]. A mathematical model of the reservoir was built using Didger and CMG STARS software[18] in order to simulate the geothermal process. The geothermal model was then subjected to a well spacing optimization as described by Bell-Eversley et al.[21]. Using the optimized model, a fluid injection analysis was carried out to compare the enthalpy produced when using the different geothermal fluids, H_2O and CO_2 as outlined by Chen et al.[16] and Avanthi et al.[15]. A CMOST sensitivity analysis varying fracture, matrix and rock properties[21] was done. The reservoir's potential to store CO_2 during the geothermal process was also simulated using CMG GEM software[14].

2.1 Description of Field

The Forest Reserve Field located in southern Trinidad as shown in Figure 2, has a net thickness of 60-200 ft. and depth ranging from 2,600 to 4,200 ft. It is located on the edge of the southern flank of the east-northeast trending the Fyzabad Anticline, which dips steeply towards the south. The field's porosity and permeability are approximately 31% and 200 md respectively. The reservoirs are deltaic in origin, formed during the Pliocene period, with several changes in the fluid paths causing numerous shale lenses[25]. As described by Mohammed-Singh and Ashok[25], the EOR 4 reservoir being studied is in the Upper Cruse sands which is underneath the Upper and Lower Forest reservoirs and consists of sand grains which range from fine to very fine. EOR 4 has a depth of 4,200 ft. and a mean temperature of 54.44°C. The EOR 4 is located near to an actual geothermal hotspot in South Trinidad near mud volcanoes, which has a geothermal gradient of up to 32°C per km[26] with a reservoir temperature of 100°C. With a reservoir temperature of 54°C and a geothermal gradient of 32°C per km, a downdip of 1,500 m is required to achieve the temperature of 100°C.

2.2 Mathematical Modelling

The mathematical model was developed to simulate the reservoir's response as described by Randolph and Sarr[14]. Using the Didger software[18], a digitised copy of the contour map was created and is shown in Figure 3. The contour map and well log data were obtained from previous work done on CO_2 immiscible projects by Mohammed-Singh and Asok[25] was then imported into CMG (Computer Modelling Group) Builder and using the STARS software and a dual permeability model of the reservoir was created[21]. The reservoir data was also obtained from the study by Mohammed-Singh and Asok[25] (shown in Table 1 and Table 2) and were inputted into the modelling software. The model also considered the different vertical layers and the Type Log data shown in Figure 3. The simulation modelling employed the temperature field to demonstrate the heat transmission methods from the reservoir to be retrieved at the surface. In terms of fracture, a fracture spacing of 10 metres in the I and J directions was assumed[27], with no fracturing in the K direction.

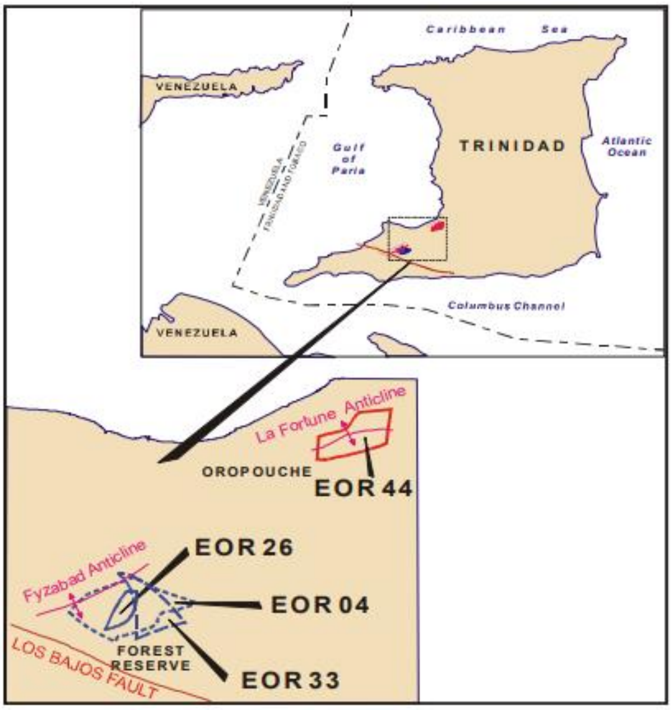

Figure 2. Location of the selected field containing EOR 4[22].

The fracture permeability and fracture porosity were calculated by the software since their values change with the fracture spacing during simulation[27]. They were calculated using the following Equations 1 and 2.

a. Fracture porosity (Frac Por) equation

$$\text{Frac Por} = 0.002\left(\frac{2}{x}\right) \quad (1)$$

where x is the value of fracture spacing (10 m).

b. Fracture permeability (Frac Perm) equation

$$\text{Frac Perm} = \frac{50}{x} \quad (2)$$

where x is the value of fracture spacing (10 m).

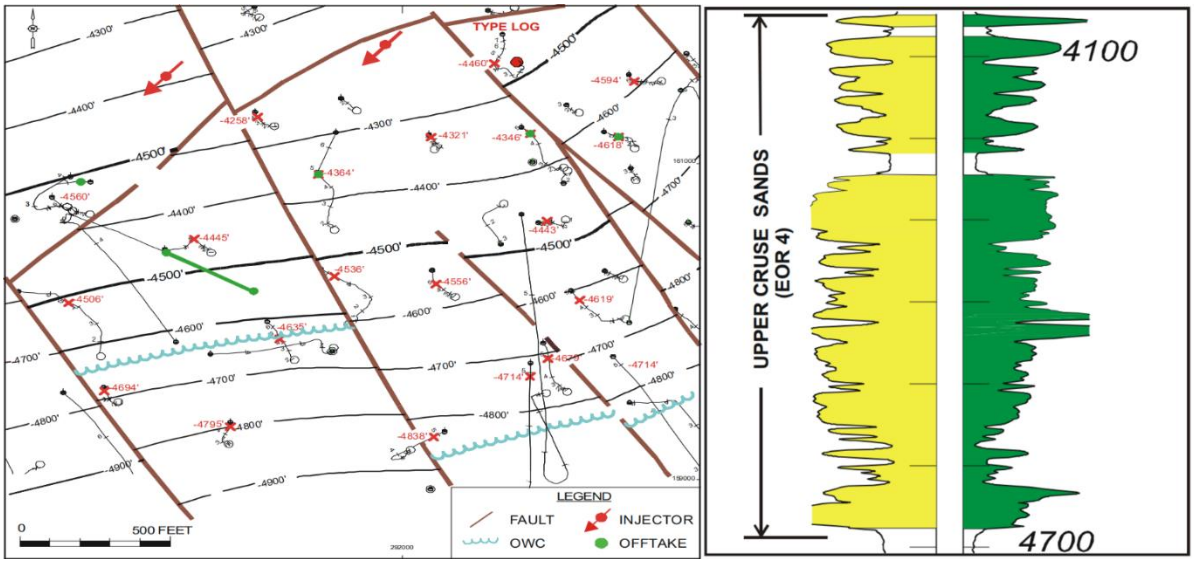

Figure 3. Structure contour map and the type log data for the selected field[25].

Table 1. Reservoir data for the selected field[25].

Property	Value	
Depth	4,200 ft	1,280.16 m
Thickness	196 ft	59.74 m
Porosity	31 %	31 %
Permeability	334 md	334 md
Temperature	130 °F	54.44 °C
Reservoir Pressure	2,200 psi	15,168.47 kPa

Table 2. Specific Properties used to develop the dual permeability model[25].

Parameter	Value	Unit
Temperature	100	°C
Matrix porosity	0.31	%
Permeability I	334	md
Permeability J	334	
Permeability K	33.4	
Reservoir pressure	15,200	kPa
Rock compressibility	4.5×10^{-7}	1/kPa
Reservoir top depth	1,280	m
Rock thermal conductivity	1.5×10^{5}	W m^{-1} K^{-1}
Rock heat capacity	2.347×10^{6}	J K^{-1}

2.3 Well Spacing

Since well spacing has been shown to have a positive effect on enthalpy produced[21], in the simulation, the distance between the wells were varied at 100 m, 200 m, 300 m and 400 m and the amount of energy produced during the geothermal process for each distance measured. The value of 400 m was the maximum distance that could be used without going beyond the boundaries of the reservoir.

2.4 Fluid Injection

To investigate the potential of EGS combined with CCS, the model will be used to compare the effect of enthalpy produced when using water and CO_2 as the geothermal fluid as described by Randolph and Sarr[14]. A comparison of the amount of energy generated during the entire lifetime of the plant (25 years or 788,940,000 seconds) for each fluid will be converted to power in order to show the capacity of both plants[21]. Equation 3 shows how power is calculated.

$$\text{Power } (W) = \frac{\text{Energy Produced } (J)}{\text{Time } (s)} \tag{3}$$

2.5 CMOST Sensitivity Analysis

The CMG's CMOST software was used to conduct a sensitivity analysis of the following parameters: matrix porosity, matrix permeability, fracture spacing in the i-direction, permeability in the K-direction, thermal conductivity, and heat capacity of the rock.

2.6 Carbon Capture and Emission Reduction

In order to model the amount of CO_2 stored in the reservoir during the runtime of the plant, the CMG GEM simulator was used. The geothermal model developed was configured to model CCS. Since CO_2 would be constantly injected and produced, it would be stored via Hysteresis, Solubility, and Mineralization phenomena. The model was run for 25 years with the amount of CO_2 stored determined. For this study, the amounts of CO_2 per kWh of energy generated will be calculated for the geothermal and the natural gas power plants as TT natural gas for all its energy production. These values were added to the amount of CO_2 stored in the reservoir in order to determine the total amount of CO_2 emissions reduced.

3 Results & Discussion

3.1 Mathematical Modelling

The base model was constructed on CMG Builder using the reservoir data shown in Table 1 and Figure 4 to simulate the geothermal model. Equations 1 and 2 were used to calculate the fracture permeability and porosity of the model, which were calculated to be 5 md and 0.4%, respectively.

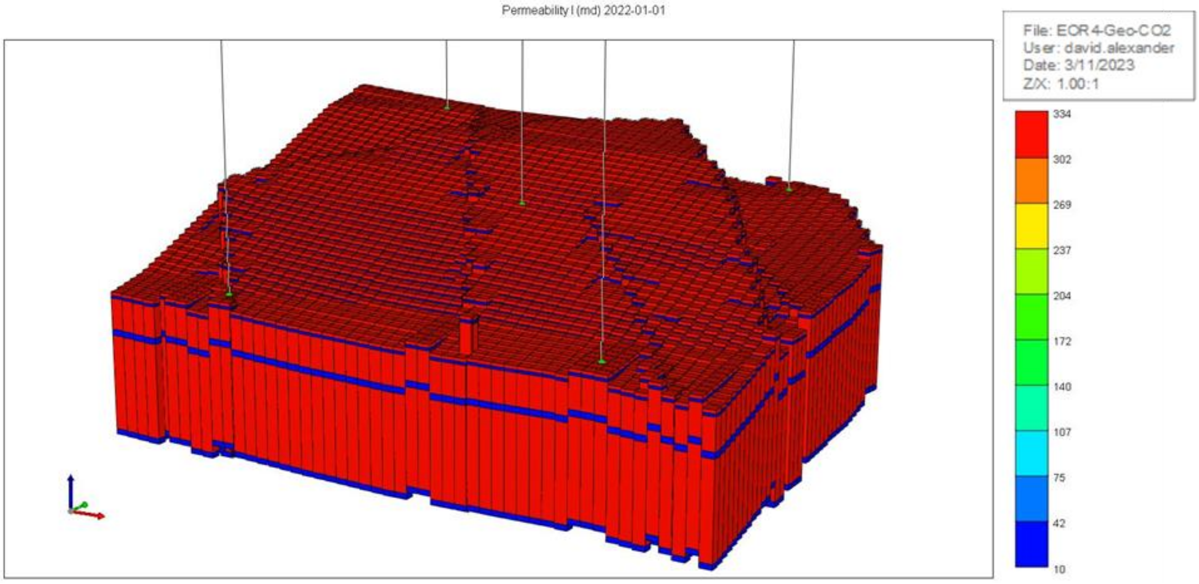

Figure 4. 3D model of the reservoir on CMG.

3.2 Well Spacing Analysis

Once the base model was created, multiple models were developed at distances of 100 m, 200 m, 300 m and 400 m between the injector well and producer wells under the constant injection pressure of 20,000 kPa and the amount of energy produced was determined. The results are shown in Figure 5. The placement was in the form of inverted 5-spot wells, with 4 producer wells forming a square and one injector well in the middle. The results showed a steady increase in enthalpy produced as the well spacing was increased. This was due to the fluid being able to exchange heat with the reservoir over a longer period while travelling a longer distance from the injector well to producer wells (Residence time). However, the increase in the amount of enthalpy produced was progressively lower with each increase in well spacing, meaning there is a limit to the positive relationship between well spacing and enthalpy produced as it approached the maximum amount of energy it could absorb from the reservoir. The reservoir was only big enough to support well spacing up to 400 m.

Figure 5 shows the amount of energy produced over the lifetime of the plant when using different well-spacings. The increase in energy produced was smaller with each increase in well-spacing, shown by the reduction in the gap between each graph line. The observation is further demonstrated in Table 3. From these results, the selected well spacing is 400 m as higher values are not possible due to the size of the well.

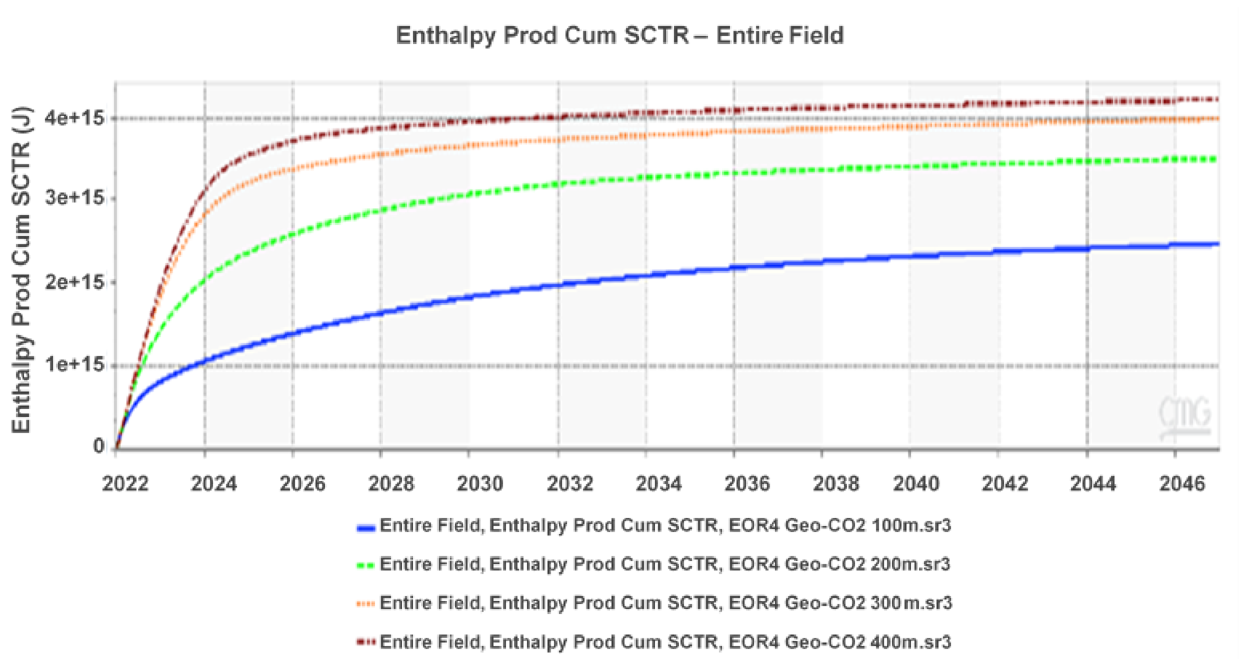

Figure 5. Cumulative enthalpy produced for different well spacings.

Table 3. The total enthalpy produced at different well distances.

Distance (m)	Energy Produced ($\times 10^{15}$ J)	Increase in Energy Produced from Previous Well-Spacing ($\times 10^{15}$ J)
100	2.48	-
200	3.51	1.03
300	3.99	0.48
400	4.22	0.23

3.3 Fluid Injection Analysis

In order to test the suitability of CO_2 as a working fluid, the geothermal model was implemented using water and CO_2 as the working fluids. Once the simulations were run, the cumulative and rate of enthalpy produced from the water model were compared to that of the CO_2 model in order to determine which had the better result. The results, shown in Figure 6, reveal that the cumulative enthalpy produced using CO_2 is higher than that produced using water. The results as depicted in Table 4 showed that the total amount of energy produced was 1.997×10^{16} J and 8.475×10^{15} J for CO_2 and H_2O, respectively, indicating that the model using CO_2 as the fluid resulted in an improvement of 1.1495×10^{16} J over the entire 25 years. This is a significant improvement considering that mass of CO_2 used is 5.3 times lesser than that of water. The CO_2 produced 2.36 times the amount of energy as water, while only using 18.7% of the amount of fluid. A very clear show of how much more capable CO_2 is in harnessing geothermal energy than water. Water was produced at a rate of 1×10^7 kg per day while CO_2 was produced at a rate of 1.87×10^6 kg per day and the amount of each fluid used was modified to achieve similar energy outputs. The superior performance of CO_2 as the fluid can also be seen in Figure 7. The rate at which enthalpy is produced is higher compared to that of water.

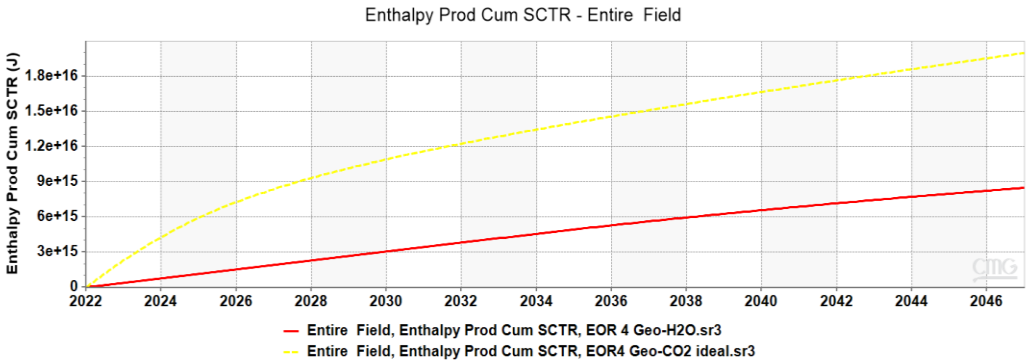

Figure 6. Cumulative enthalpy production using H_2O and CO_2.

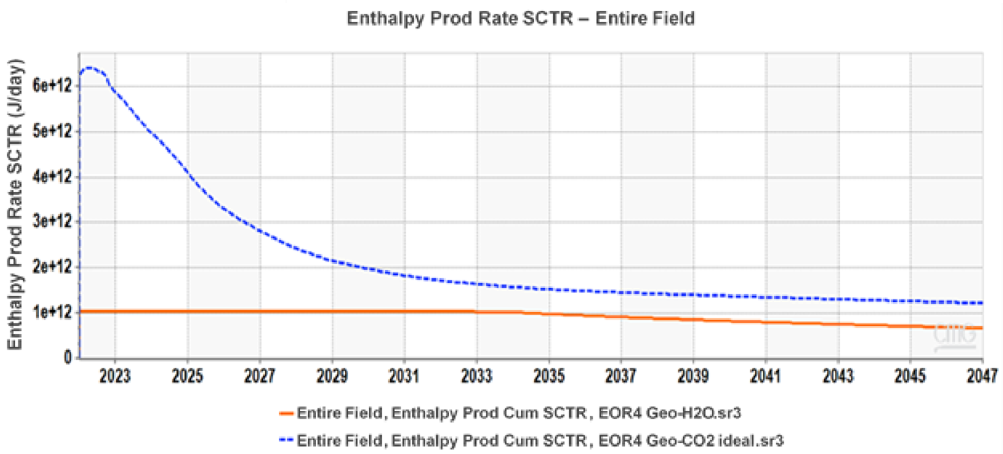

Figure 7. Enthalpy production rate using H_2O and CO_2.

Table 4. A comparison of performance parameters using different working fluids.

Fluid	Energy Produced (J)	Time period (years)	Power Capacity (MW)	Fluid production rate ($\times 10^6$ kg per day)
CO_2	1.997×10^{16}	25	25.31	1.87
H_2O	8.475×10^{15}	25	10.74	10

3.4 *CMOST Sensitivity Analysis*

CMOST was used to ascertain the effect of various factors on the overall amount of enthalpy produced in the simulation. Factors which included matrix porosity, matrix permeability, fracture spacing, permeability anisotropy, thermal conductivity of reservoir rock and heat capacity of reservoir rock are shown in Table 5. It can be seen in Figure 8 that fracture spacing accounted for 96% of the increases, while the rock heat capacity accounted for 2.1%. This is because fracture spacing directly affects the permeability of the natural fracture, which determines how well the fluid and heat flow. Fracture spacing also determines the shape factor as in Equation 4.

$$\text{Shape factor} = \frac{1}{L_i^2} + \frac{1}{L_j^2} + \frac{1}{L_k^2} \tag{4}$$

where L_i, L_j and L_k are the fracture spacing in *i*, *j* and *k* directions[28].

When the fracture spacing is large, the shape factor is small. This means that the fluid and heat flow favour fracture flow instead of matrix flow and the fluid travels fast through fractures. The base case used was the simulation of the actual values of the reservoir properties which produced

7.2×10^{14} J of energy and is shown by the black line in Figure 9. Also shown in the sensitivity analysis in Figure 9, the amount of energy produced increased to a maximum of 1.57×10^{15} J, with Fracture Spacing being the main factor causing the increase. The other factors all had a less than 2% contribution to the increases. The matrix properties such as porosity and permeability have a much smaller effect on the enthalpy produced. This also goes for the thermal conductivity and heat capacity of the rock. This is because the heat transfer is mostly between the fluid and the natural fractures and not heat transfer between the fluid and the rock.

Table 5. Input parameters for CMOST analysis.

Parameter	Lower limit	Base case	Upper limit	Unit
Matrix porosity	0.05	0.1	0.15	%
Matrix permeability	5	10	100	md
Fracture spacing, I	2	10	50	M
Permeability, K	0.05	0.1	0.25	md
Rock thermal conductivity	1.12×10^5	1.5×10^5	1.88×10^5	$W\ m^{-1}\ K^{-1}$
Rock heat capacity	1.760×10^6	2.347×10^6	2.934×10^6	$J\ K^{-1}$

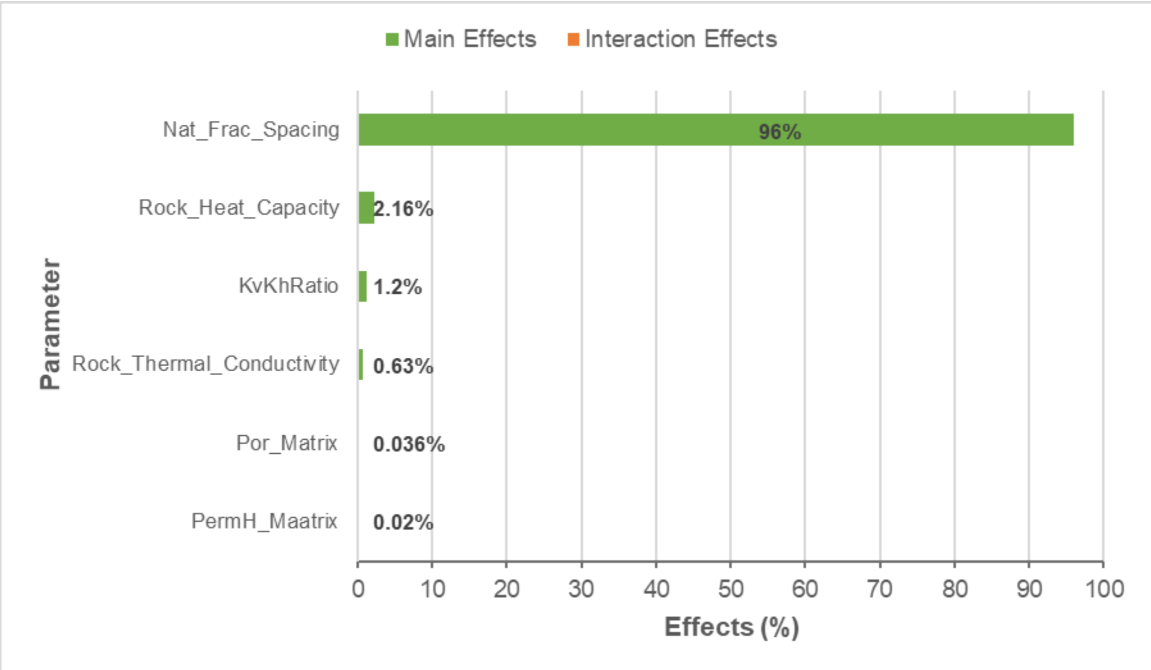

Figure 8. The overall effect of each parameter on the enthalpy produced.

3.5 Carbon Capture and Sequestration

The CMG GEM simulator was utilized to model carbon capture during the harvesting of geothermal energy. The model was developed utilizing the same parameters as the geothermal model, with constant fluid injection and production, and the CO_2 being stored via Hysteresis, and Solubility. The results shown in Tables 6 and 7 indicate that of the 1.70663×10^9 kg of CO_2 injected, 1.75129×10^7 kg was stored via hysteresis, and 2.94907×10^7 kg was stored in solution (dissolved in water), which gives a total of 4.7004×10^7 kg of CO_2 stored in the reservoir over the 25-year period. Since the use of geothermal energy systems in TT is in the exploratory stage, there is an absence of field case projects locally. Verification of the numerical simulations was achieved utilizing real field data as analogue from a previously established methodology for performing the numerical simulations[21]. The results from the simulated sensitivity analyses performed in this study were compared to those from previous studies in TT. The results indicated that the cumulative enthalpy obtained was comparable to those obtained by previous studies in TT offering further validation[18,21].

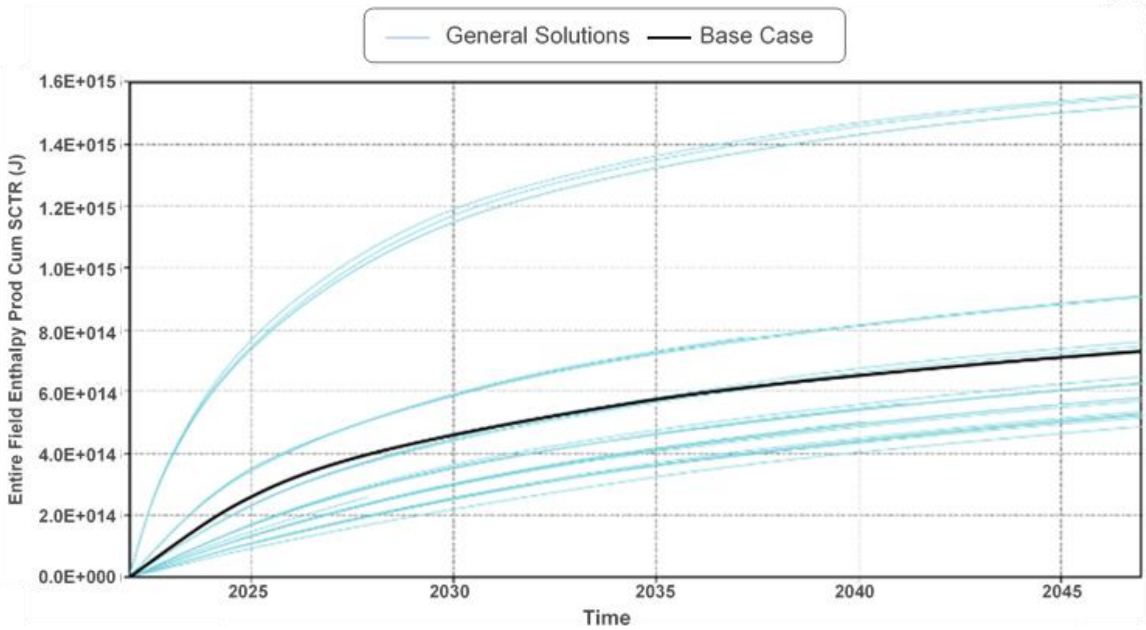

Figure 9. CMOST sensitivity analyses.

Table 6. CO_2 storage capacity in the reservoir by component.

Component	Injected / gmole	Produced / gmole	Accumulated / gmole
CO_2	3.87788×10^{11}	3.81356×10^{11}	6.43302×10^{9}
CH_4	0	0	0
H_2O	0	1.24568×10^{12}	-1.24568×10^{12}

Table 7. CO_2 storage capacity in the reservoir by trapping mechanism.

CO_2 storage capacity in the reservoir	Moles	kg
Trapped / Hysteresis	3.97931×10^{8}	1.75129×10^{7}
Dissolved in Water	6.70092×10^{8}	2.94907×10^{7}
Total	1.06802×10^{9}	4.70036×10^{7}

3.6 CO_2 Emission Reduction Analysis

According to the research done so far, geothermal energy generation has significantly less negative impact on the environment when compared to hydrocarbon energy generation and a comparison between the estimated emissions of a geothermal plant and hydrocarbon power plants[29] is shown in Table 8.

Table 9 clearly shows that Geothermal energy produced significantly less CO_2 emissions even when compared to natural gas power plants which are used in Trinidad and Tobago. The reduction in emissions would be equal to 1.937×10^{9} kg of CO_2, producing 1.7973×10^{16} J of energy over the 25-year period. When added to the 4.7004×10^{7} kg of CO_2 stored in the reservoir via Hysteresis and Solution, this increases the amount of CO_2 reductions to 1.984×10^{9} kg of CO_2.

Table 8. Predicted CO_2 emissions from hydrocarbon and geothermal plants[29].

Energy production method	Total CO_2 emissions / 10^6 kg
Coal	4,842
Petroleum	3,545
Natural Gas	2,346
Geothermal	409

Table 9. CO_2 emissions from various energy production methods[29].

Emissions	Geothermal	Coal	Petroleum	Natural Gas
lbs CO_2 per kWh	0.180	2.13	1.56	1.03
kg CO_2 per kWh	0.082	0.97	0.71	0.47

3.7 Cost Analysis

For a standard geothermal plant that uses water, the capital cost is approximately US$ 2,500 per kW[30]. Since the geothermal reservoir simulation in this study produced 10.74 MW of power and assuming it is 90% efficient, this equates to 9.67 MW, which translates to US$ 24,175,000 for the cost of the plant. For this study which considers a geothermal plant using CO_2 as the working fluid, if the capital cost is constant (although it is expected to be lesser due to the lighter nature of the CO_2), the geothermal plant produces 22.78 MW and with a 90% efficiency equating to 25.31 MW of power. The plant would effectively cost US$ 1,061.24 per kW, which is superior in cost efficiency.

4 Conclusion

This study demonstrated that CO_2 efficiently works as a geothermal fluid. When using CO_2, the amount of energy produced was 1.997×10^{16} J with a fluid production rate of 1.87×10^6 kg per day, whereas water produced 8.475×10^{15} J of energy with a 1×10^7 kg per day fluid production rate, an improvement of 1.1495×10^{16} J while using 0.187 times the amount of fluid for CO_2. This amount of energy produced via geothermal energy resulted in a reduction of 1.937×10^9 kg of CO_2 when compared to the emissions from a natural gas power plant such as those in TT. In terms of carbon storage, the reservoir can store 4.7004×10^7 kg of CO_2 via hysteresis and dissolving in water. When the amount of CO_2 sequestered is combined with the amount of emissions reduced by using geothermal energy, the total amount of emissions reduction was 1.984×10^9 kg of CO_2, highlighting the excellent capability of using CO_2 as the geothermal fluid. The plant would effectively cost US$ 1,061.24 per kW which is superior in cost efficiency. This paper shows that there is an enormous potential in using CO_2 as the working fluid for geothermal power generation in abandoned oil wells such as EOR4 in Trinidad and Tobago. It offers a low-carbon energy generation strategy associated with a carbon emission reduction technology.

Conflict of Interest

The authors declare that there was no conflict of interest.

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Author Contribution

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Data curation: Alexander, D., Boodlal, D., & Maharaj, R.
Methodology: Alexander, D., Boodlal, D., & Maharaj, R.
Formal analysis: George, T.
Visualisation: Not applicable
Software: George, T., & Alexander, D.

Writing: George, T.
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