PERFORMANCE OF A GEOTHERMAL SYSTEM IN PETROLEUM FIELDS OF THE TARANAKI REGION, NEW ZEALAND

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ABSTRACT

Extracting energy from petroleum fields is an attractive topic for research. In the Taranaki region, some of the depleted oil and gas reservoirs are prospective candidates for low-temperature geothermal development. This is because the hydrocarbon wells produce a large amount of coproduced water at the surface.

Therefore, we analyse one of the hydrocarbon fields encountering fractured reservoirs in the Taranaki region. We aim to estimate the production rate and well separations to sustain generation capacity from the field for 10 years.

We used the Volsung reservoir simulator to simulate the reservoir models using the MINC (the Multiple INteracting Continua) formulations and representative rock properties. Then we analysed the behaviour of the petroleum reservoir over time with the extraction of geothermal energy.

It was found that a flow rate of 180 kg/s is sufficient to produce 6 MW of electricity and could be sustained for at least 10 years. The work suggests that the theoretical maximum production rate between production and reinjection well separated by 500 m would be 220 kg/s before the production enthalpy declined below 20% of the initial value. But the field has several wells and larger separation between the production and injection wells. The model of the field has seen production rates of 180 kg/s to sustain a generation capacity of more than 6 MW without the evidence of any thermal breakthrough from the injection well over a period of 10 year. The model demonstrates the effective movement of the warmer fluids from the lower formations to the upper reservoir for higher production rates before the arrival of the cold waterfront from the reinjection well.

For future analysis, it is recommended to conduct optimisation of the operation strategy in the field. A detailed thermo-economic study could also be performed to analyse the benefits of ultimate oil recovery, aquifer effect, and the onsite power demand.

1. INTRODUCTION

Geothermal energy extraction from petroleum fields is being actively explored around the world (Horvath et al., 2018; Kurnia et al., 2021; Li et al., 2018; Nian & Cheng, 2018; Sui et al., 2019). It may be possible to achieve low-risk, affordable, and commercial development from an already producing field at the end of its life (Kharseh et al., 2015; Reyes, 2015). The drilled wells in place, the infrastructure to collect fluid at the surface, the years-old information about the field operation and behaviour, and the skills and expertise available from the petroleum industry would benefit any geothermal evaluation efforts. Such mature oil and gas fields co-produce hot water along with the hydrocarbons as a waste stream that could be utilised to harness geothermal energy. In a thermo-economic analysis, Kharseh et al., (2015) report a levelized cost of electricity to be below US$ 0.06 /kWh for such plants.

Additional challenges are associated with energy extraction from petroleum fields. First, the temperatures found in petroleum reservoirs are mostly low (<170 ℃) which means a lower inherent thermal energy potential than the typical high temperature reservoirs.. Second, these fields usually produce at lower rates than those found in typical geothermal counterparts. Third, the long-time hydrocarbon production may have depleted the reservoir of its initial pressures in the absence of any pressure support, e.g., from an aquifer or reinjection. Consequently, it becomes important to evaluate the geothermal prospects of a mature petroleum field.

Recent literature has reported that naturally fractured reservoirs have considerable potential and could be used for extracting geothermal energy (Montanari et al., 2017; Trumpy et al., 2016). The heterogeneous nature of a fractured reservoir creates additional challenges during energy extraction. It is important to predict the reservoir temperature and production behaviour of the field to develop a successful project.

Several researchers have performed a similar analysis in oil and gas fields which may or may not include fractured reservoirs. LB oil reservoir in Huabei oilfield, China, has an operational power plant on a depleted field (Xin et al., 2012). The reservoir simulation study in this naturally fractured carbonate reservoir showed the importance of an appropriate reinjection rate and reinjection temperature (Gong et al., 2011). Similarly, Naval Petroleum Reserve No. 3 (NPR3) at Teapot Dome Oilfield, US is another example of a successful geothermal power generation operation from co-produced fluid from a fractured reservoir (Nordquist & Johnson, 2012). Several other successful examples of low-temperature geothermal developments in typical fields other than petroleum ones are available in the literature (Febrianto et al., 2019). Only a few investigations in the petroleum fields have revealed energy extraction attractive for electricity generation (Kurnia, J. C. 2021). A heat transfer study conducted in the Shunbei field, China, suggests that the reservoir heat storage ratio and the heat inter-porosity coefficient can be useful to evaluate the feasibility of geothermal generation in an abandoned field (Wei et al., 2021).

The present work attempts to evaluate the feasibility of geothermal energy generation from one of the petroleum fields of the Taranaki region, New Zealand. The document is structured as follows: Section 2 introduces Waihapa/Ngaere field which is a potential candidate for geothermal development. Section 3 briefly highlights the methodology and discusses the results for estimating the suitable flow rate and distance between the injection and production wells to sustain the generation capacity. Section 4 describes a more realistic model of the field to estimate the generation capacity from the field. Conclusions from our analysis are listed in Section 5 before the future work which is outlined in Section 6.

2. WAIHAPA/NGAERE FIELD

Waihapa/Ngaere is the only naturally fractured reservoir in the Taranaki region, New Zealand (Hood, 2000). New Zealand Energy Corp. operates this field, which was discovered in 1988 (Hood et al., 2002; Lock et al., 1986). The reservoir depth is around ~2500 m TVSS (True Vertical Sub-Sea) (Adams, 2019) and the Original Oil In Place (OOIP) was about 32 million barrels (MBIE, 2020). The field saw a peak oil production of more than 27.6 kg/s (Adams, 2019). By the end of 2018, it had produced 24 million barrels of oil.

Petroleum production in this mature field is continuously reducing (Adams, 2019; MBIE, 2020). The reservoir in the field is connected to a stable aquifer and maintains constant pressure support (Adams, 2019). The reservoir temperature is greater than 140 ℃ at a depth of 4,823 m, which represents a substantial in-situ thermal energy resource (Lock et al., 1986, p.376). The reservoir porosity is low; however, the existing network of fractures provides a high permeability of around 5 D (Adams, 2019, p.7). In this field, some wells are still producing oil along with water indicating the pressure at the wellhead above the corresponding bubble point pressures (Adams, 2019).

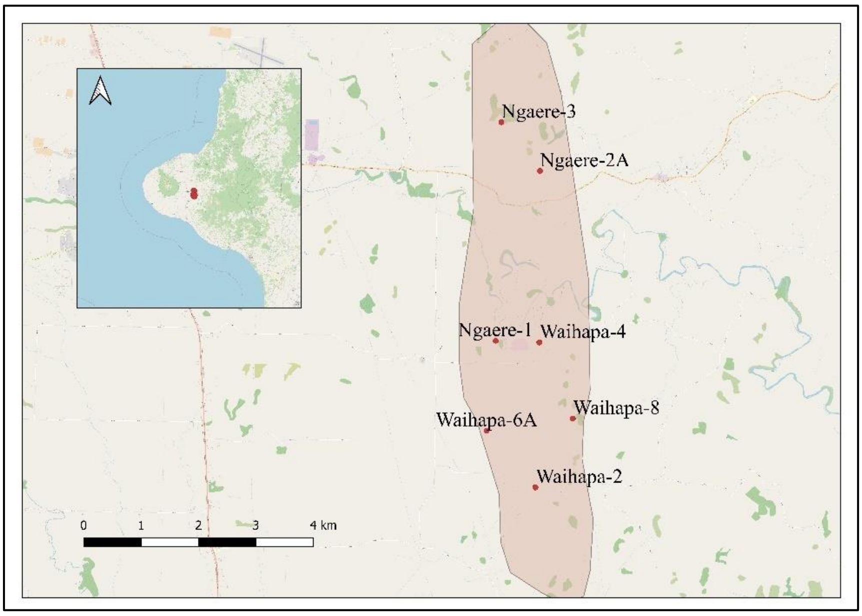


Figure 1: Waihapa-Ngaere field in the Taranaki region of New Zealand.

The co-produced fluid's temperature is around ~89 ℃ and the flow rate is around 3.8 kg/s of hot water at the wellhead. The reservoir pressure measured in Waihapa-1A was around 689.48 bar (Lock et al., 1986, p. 16). The field has around ~33 kg/s water injection capacity and about 46 kg/s oil handling facility (Adams, 2019). This field is considered to evaluate the potential to support a geothermal development project.

3. PRELIMINARY MODELLING

A preliminary model was first set up to constrain some of the parameters such as the flow rate, separation distance, and the input conditions for our field model later (see Figure 2). This model has a doublet system, i.e., a production and an injection well. A 1 km by 1 km extent of the field is simulated with all the layers below the fractured reservoir to 2000 m (GNS, n.d.). The Kaimiro formation is the deepest formation tested in this field, and temperatures around 145 ℃ were measured (Lock et al., 1986). The model is run for 10 years to see if the enthalpy of production drops below 20% below its initial value as a threshold for having an impact.

This modelling considers a 100 m fracture spacing in the reservoir with 5% porous matrix rock. The MINC (the Multiple INteracting Continua) formulations (Pruess, 1999) is used to model the fractured reservoir using the Volsung reservoir simulator (Franz & Clearwater, 2019). Fractures contribute significantly to the flow of fluid in the reservoir, and therefore 100 m spacing and 50% porosity is assumed for the fractured medium (Adams, 2019). The Kaimiro formation in the model is at a higher pressure and temperature, i.e., around ~689.48 bar and ~145 ℃, respectively (Lock et al., 1986). The reservoir elevation used for production is at a pressure of ~329.57 bar and a temperature of ~90 ℃ (Lock et al., 1986). The other formations are given average values of the interpolated pressure and temperature during the simulation.

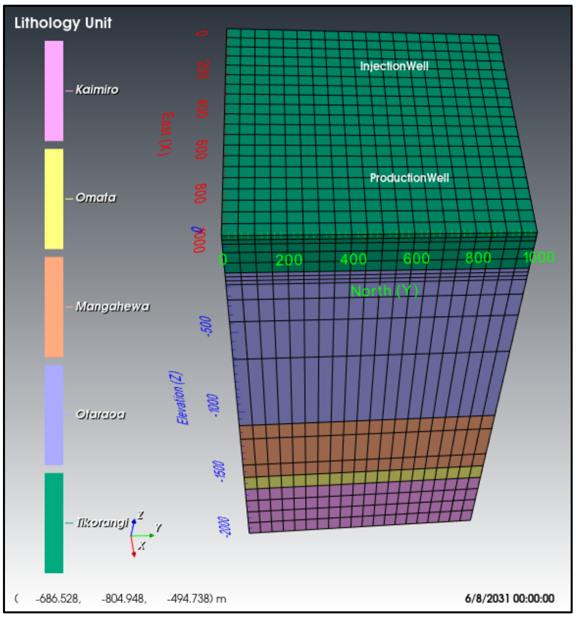
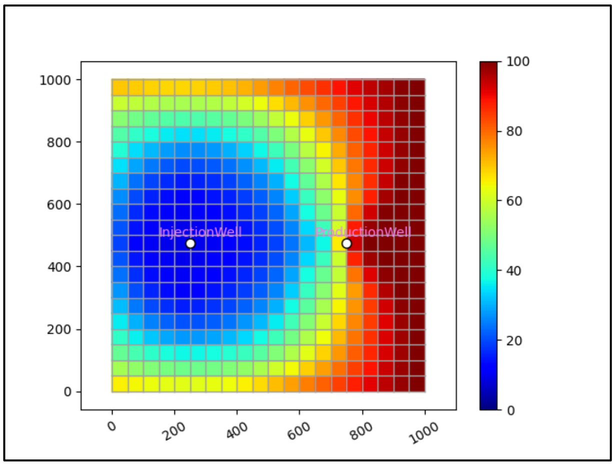
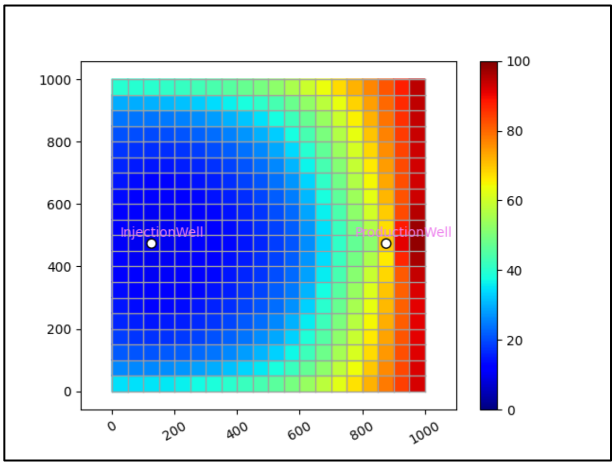


Figure 2. Preliminary model grid with 2000 m depth layers showing different geological units.

Figure 3 shows the distribution of temperature after a decade of production. The cold waterfront from the injection well reaches the production well. The higher temperature is farther from the production well to the right Figure 3(a), and the peak in the curve shown in Figure 4 depicts induced to flow from lower warmer formations. In the case of a decade-long production, the relative movement of the cold waterfront is greater than the thermal exchange with lower formations and therefore, results in an overall enthalpy decline. Thus, it is estimated that a production rate of 220 kg/s for 500 m distant wells can be sustained over a decade-long generation from a plant.



(a) Horizontal slice of the reservoir temperature distribution at a depth of 130 m after 10 years for 220 kg/s production rate for a 500 m separation between the wells.



(b) Horizontal slice of the reservoir temperature distribution at a depth of 130 m after 10 years for 355 kg/s production rate for a 700 m separation between the wells.

Figure 3. Temperature distribution is shown for a doublet producing at 220 kg/s and 355 kg/s for 500 m and 700 m distant wells.

From Figure 4 we can also conclude that as the separation increases, it is possible to draw more amount of fluid from the system without a significant decline in the production enthalpy. It was found that 355 kg/s of fluid provides sustainable energy output when the distance between the injection and the production well is 700 m. This model has served to constrain some conditions for a more realistic model of the field. Also, we have found estimates of sustainable flow rates and suitable separations between injection and production well for ten years.

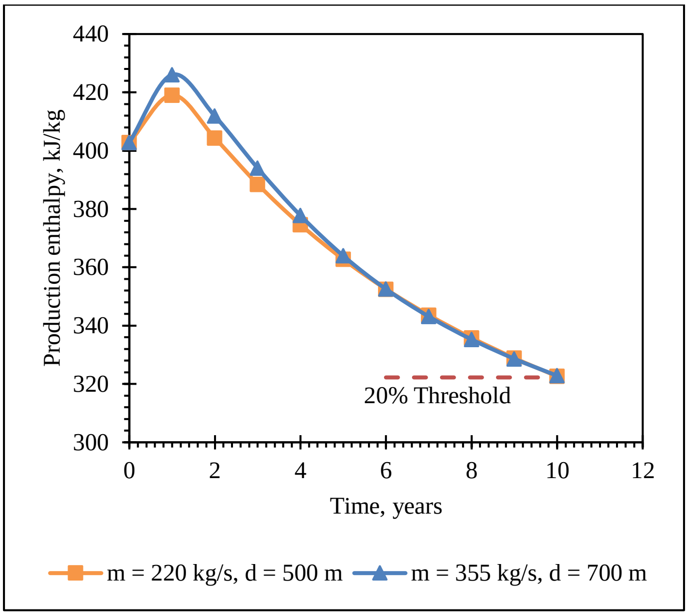


Figure 4. Decline in production enthalpy with respect to time for 220 kg/s and 355 kg/s production rate after 10 years for 500 m and 700 m apart wells, respectively.

4. FIELD MODEL

4.1 Model set-up

Results of the preliminary model suggest a minimum variation of temperature below 1100 m depth. This understanding helped improve and develop a more realistic field model as shown in Figure 5. The model is based on known reservoir conditions, with 6 production wells and 1 reinjection well in an 11 km long and 3.5 km wide field with two geological units extending to 1100 m depth. Overall, this model allows more flexibility in terms of choosing the number of wells and the distances between different production and reinjection wells. The analysis assumes the reservoir is initially filled with water.

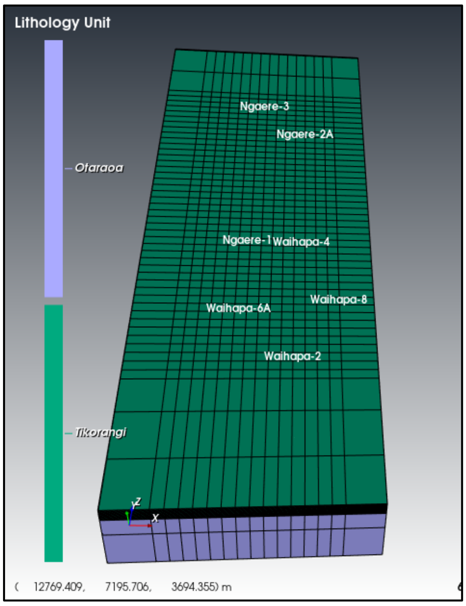


Figure 5. Model based on the Waihapa/Ngaere field with the recent producing wells and their locations.

At the initial reservoir conditions, 25 kg/s of flow would produce 1 MW of electricity. This assumes an Organic Rankine Cycle (ORC cycle) which generally operates on a 10% conversion efficiency (Eyerer et al., 2020; Zarrouk & Moon, 2014) for a typical geothermal system. The present analysis assumes that the binary plant reduces temperatures from 90 °C to 19 °C. A flow rate of 30 kg/s would be sufficient to generate 1 MW of power. For testing resource limits, we assume maximum production flow of 30 kg/s, and reinjection of 40 kg/s which are consistent with current well output. Higher injection is chosen because lower enthalpy systems have more wastewater available to reinject (Kamila et al., 2021). For scenarios with more than 30 kg/s of total production, new reinjection wells are required.

4.2 Estimating the generation capacity of the field.

Figure 6 shows the change in enthalpy over time for three different total production rates. The average production enthalpy increases over the production time for all the production rates. The greater separation between production and injection in this field has contributed positively to energy extraction.

The thermal energy from the lower formations is effectively utilised by the production wells. The hotter fluid from the lower formation moves into the upper production reservoir and contributes to the overall increase in the total production enthalpy. 180 kg/s was assumed to be a possible maximum extraction rate for the field with the current production wells, requiring 4 new reinjection wells.

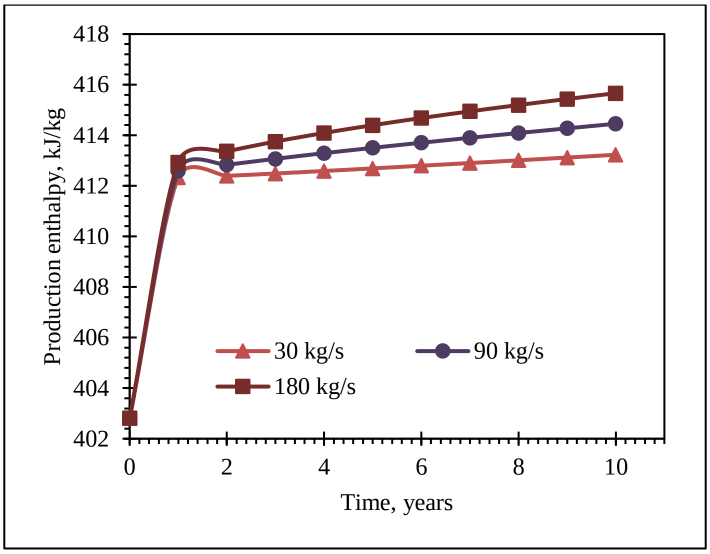
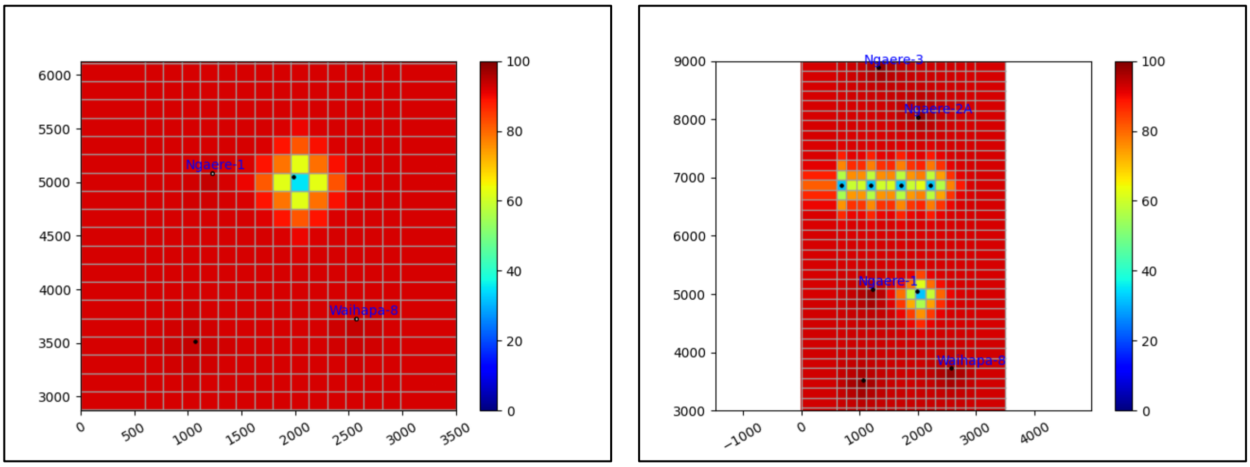


Figure 6. Simulated average enthalpy change over the production time of 10 years for the field showing three different total production rates.

But a more detailed analysis is needed to assess this assumption.



(a) Horizontal slice of the reservoir temperature distribution at a depth of 180 m after 10 years for 30 kg/s total production rate in the field.

(b) Horizontal slice of the reservoir temperature distribution at a depth of 180 m after 10 years for 180 kg/s total production rate in the field.

Figure 7. Temperature distribution for 180 kg/s and 900 kg/s total production rate from the field.

Figure 7 shows the temperature distribution in the field for both 30 kg/s and 180 kg/s total production rates. In Figure 7(a), the two wells shown are separated by nearly 1000 m distance. The cold waterfront from the injection well did not reach the nearest production well after 10 years. Moreover, the heat from the lower formations is effectively produced from the production well even after an operation period of a decade. Figure 7(b) shows that when each well is contributing 30 kg/s, and 4 additional wells for complete reinjection, assuming 40 kg/s as the maximum injection rate possible, cooling is not observed at the production wells. Apart from this, the hotter fluid from the lower formations is drawn to the production wells and contributes to an overall increase in the production enthalpy. It is concluded that the field could be operated successfully with a total production rate of 180 kg/s, thermal energy of around 333.39 kJ/kg, to sustain a generation capacity of 6 MW.

This is a preliminary model, and more detailed analysis is required to estimate the sustainable energy capacity of the reservoir, including oil recovery. Oil recovery from the field can contribute to improving the economics of setting up a geothermal power plant. Therefore, the effects of the aquifer, ultimate oil recovery, fluid handling issues, selling price, levelized cost of electricity, power purchase agreement, and onsite power demand should be considered in a detailed thermo-economic study of the field.

5. CONCLUSION

Waihapa-Ngaere field is the only naturally fractured reservoir in the Taranaki region of New Zealand. It has seen some of the highest production rates in the history of operation of the field (i.e., > 25 kg/s). The deepest formation tested in the Waihapa-Ngaere field has an average reservoir temperature of more than 140 ℃. Moreover, there is a large aquifer connected to the field which supports the pressure in the reservoir. The field is selected to evaluate the prospects of geothermal energy extraction. Following conclusions have been made after evaluating the field using reservoir simulations:

1. A doublet configuration having injection and production well located 500 m apart would encounter a 20% drop in the production enthalpy after 10 years when produced at 220 kg/s.

2. Waihapa-Ngaere field offers flexibility with the selection of the number of injection and production wells and the distance between these wells. The greater separation between the wells in the field allowed effective utilisation of the thermal energy from lower formations and did not encounter thermal breakthrough.

3. A total production rate of 180 kg/s can sustain a generation capacity of 6 MW for 10 years. A generation capacity of slightly above 6 MW could be sustained; however, further analysis is needed to understand the sensitivity to reservoir properties, assumed production and reinjection rates.

4. A thermo-economic study should be undertaken in the future to evaluate the cost-benefit analysis of having aquifer support, ultimate oil recovery, and onsite power demand.

6. FUTURE WORK

1. The field should be considered for operation and production strategy optimisation to achieve maximum benefit from energy extraction in the field.

2. The prospects of using alternate fluids such as supercritical CO_2 for enhancing energy extraction from the field should be considered in some of the dry wells of the field. There is a growing interest in the CO_2-EGS system which can be developed in petroleum fields utilising abandoned and/or dry wells.

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