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Evaluating the Cost-efficiency and Sustainability of Geothermal Projects: A Study on Onshore Oil Wells in the United Arab Emirates

BY

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Abstract

The United Arab Emirates (UAE) has long been recognized as a global leader in the oil and gas industry. However, the UAE's ambitious vision for sustainable energy and the pressing need to diversify its energy portfolio have led to increased interest in alternative energy sources, including geothermal energy. Although the resource is continuously available, geothermal energy production involves high exploration, drilling, and completion costs. This study explores the cost-efficiency of repurposing existing hydrocarbon wells for geothermal production or co-production, as a solution to mitigating the high costs of drilling new wells.

The research framework encompasses a thorough review of existing literature, case studies of successful geothermal projects worldwide, feedback from industry experts, and on-site data (primary data) collection from selected hydrocarbon wells. The study employs a quantitative research method to evaluate the operating parameters of onshore hydrocarbon wells to develop financial models for geothermal energy production units. Through a detailed economic assessment, the study investigates the financial benefits of adapting existing oil wells for geothermal energy production, considering the geological and geothermal characteristics of the UAE's subsurface. The resulting financial indicators are compared to those of geothermal projects from newly drilled wells.

The key findings of the research are that geothermal energy production from the studied hydrocarbon wells exhibit an average Levelized cost of energy (LCOE) of 0.055 USD/kWh which is lower than the market sales price for electricity by 0.025 USD/kWh, and lower than the reference geothermal projects from new wells by 0.007 USD/kWh. The proposed co-production model promises higher returns for a shorter period, with better resilience to high costs of capital. The study concludes by offering valuable insights into the potential for geothermal energy and recommendations to complement the UAE's energy mix while contributing to its sustainability goals. The recommendations are aimed at guiding policymakers, oil and gas and geothermal industry stakeholders, and future researchers in fostering a more sustainable energy future for the UAE and beyond.

Introduction

Amidst the global climate crisis, major energy industry stakeholders are seeking ways to decarbonize their operations. Because the oil and gas value chain accounts for (directly and indirectly) 42 % of global greenhouse gas emissions (Beck, et al., 2020), governments and leading industry players in the Middle East have started to move towards a cleaner future by facilitating initiatives that foster sustainable energy production. In addition to its $40 billion investment in clean energy over the last 15 years, the United Arab Emirates (UAE) has announced $160 billion investment in clean and renewable energy sources over the next 30 years as its commitment to a net-zero future (Trade Arabia, 2022). Among these renewable energies sources is geothermal, which has been lagging due to slow technological developments and poor scalability when compared to other more popular sources – wind, solar, and hydro (Li, 2013). The exploration of the geothermal resource, which consist of drilling deep into water reservoirs to harness heat which can then be used to warm households, or to generate electricity, or to do both, exhibits several similarities to oil and gas exploration and production. Empowered by their years of exploration and drilling experience and threatened by the volatile prices and the cratering oil and gas demand due to the pandemic, several oil and gas players are adopting geothermal ventures as a fitting path into the energy transition (Roberts, 2020). While most start-ups focus their R&D teams on the development of resilient and long-reach geothermal technologies, oil and gas companies with existing technological infrastructure seek ways to repurpose the latter for a cost-effective geothermal exploration (Jello, et al., 2022). Oil wells drilled into mature reservoirs with a high water cut which makes oil and gas production either challenging or non-profitable, alongside an ascertained

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porosity and permeability, may be significant assets in the extraction and valorisation of hot water from the earth.

Sustainability

The United Arab Emirates is home to vast oil reserves. However, onshore exploration, extraction, and production have far-reaching environmental and social consequences, leading to unique sustainability challenges that policymakers continue to mitigate. Given the arid nature of the land, the development of every new drilling project requires substantial amounts of water which exacerbates water scarcity concerns. The delicate ecosystems and biodiversity (flora and fauna) are also at risk due to habitat destruction, soil contamination, and degradation due to the release of pollutants during drilling and extraction activities. Repurposing depleted oil wells eliminates the need for a new geothermal drilling project and eliminates the risk involved in oil well disposal. Furthermore, the economic dependency on fossil fuels poses long-term social challenges and sustainability challenges, hinting towards a diversification of portfolio for several oil and gas industry players. Ultimately, the use of depleted oil wells for geothermal energy production provides a low-carbon option to addressing the ever-increasing energy demand, thereby controlling the impact of energy production on the environment.

Geothermal Technology – Development and Scalability

The concept of repurposing oil wells for geothermal production emerged as a means of leveraging on existing infrastructure and expertise while fostering renewable energy sources for sustainable and efficient power generation. In the 1960s, The Geysers geothermal field in California, United States, known for its high-quality steam, was discovered within an oil field. The oil wells were transformed into geothermal wells, and The Geysers became the world's first large-scale geothermal power plant, producing electricity from the Earth's heat. In the 1970s, the oil crisis and growing environmental concerns prompted further exploration of repurposing oil wells for geothermal energy. In Canada, the Leduc oil field was converted into a geothermal energy production site, utilizing the heat stored within the reservoirs.

More recently, countries with significant oil and gas reserves have recognized the potential of repurposing oil wells for geothermal production. In locations where existing oil wells are too shallow, geothermal energy production may not be cost-effective, and deeper drilling may be required. That notwithstanding, recent technological advancements of geothermal technologies such as innovative binary and closed-loop systems may allow for lower-temperature geothermal resources to be utilized effectively.

The scalability of geothermal technologies is evident in large-scale projects, like the Hellisheidi geothermal power plant in Iceland, which supplies electricity and heating to a significant portion of the capital city. Additionally, modular designs and standardized components facilitate the replication and expansion of geothermal installations, enabling the deployment of geothermal systems in diverse geographical regions. Oil and gas companies with sound experience in standardizing drilling and extraction operations can play a key role in the development of the geothermal technology.

Economic Viability

Although several decision makers may use policy and legislation to drive the energy transition, economic viability continues to play a crucial role in the transition towards sustainable energy sources. As countries seek to reduce their reliance on fossil fuels and mitigate climate change, it is essential to ensure that renewable energy technologies are economically feasible and competitive. Economic viability drives investment and market adoption where environmental stewardship and corporate social responsibility alone are ineffective. Investors and businesses are more likely to allocate resources towards low-risk renewable energy solutions with ascertained cost-competitiveness and financial gains. Oil and gas companies are therefore exploring low-carbon solutions that align with the current drilling and production operations: geothermal production, and Carbon Capture and Underground Storage (CCUS). This will lead to increased deployment of clean energy technologies and stimulates economic growth, job creation, and innovation in the renewable energy sector. Adding geothermal energy production to the energy portfolio can only be sustainable if it is cost-effective. The economic viability of the technology will promote affordability, thereby boosting adoption and stabilizing the overall cost of energy within the fossil fuel-dominated portfolio.

Problem Statement

As a leading contributor to greenhouse gas emissions, the oil and gas industry has the responsibility to participate in addressing the global climate crisis. According to Oil and Gas Middle East, GCC upstream carbon emissions could increase 30% by 2030 if steps are not taken (Oil and Gas Middle East, 2020). In this pursuit of sustainable energy development, Oil and gas companies within the region are seeking environment-friendly solutions that are also economically viable. Considering the wide network of existing oil wells, geothermal energy production appears to be one of the low-hanging fruits as its development exhibits several similarities with oil and gas operations. The nature of depleted reservoirs with water drive mechanisms make repurposing existing oil wells an interesting option since it eliminates the substantial financial and technological challenges involved in drilling a new well. However, these wells – drilled for oil exploration – have been in operation for years. The current geothermal heat content and state of the infrastructure must be evaluated to confirm the economic benefits of repurposing over geothermal development from scratch.

Aim of the Research

This study aims to investigate the cost-efficiency of using depleted onshore oil wells in UAE for sustainable geothermal energy production.

Research Question

The main question to be answered by this study is as follows: "Is repurposing depleted oil wells in the UAE for sustainable

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geothermal production more economically viable than drilling new geothermal wells?"

LITERATURE REVIEW

Energy Transition and the Oil and Gas Industry

While the global energy crisis rages, energy transition gains significant momentum. Governments worldwide have implemented policies and enabled favourable infrastructure for industries to drive the technological advancement and shift towards sustainable, affordable, and secure energy production. Global investment in renewable energy is steadily and significantly surpassing that in fossil fuels and is expected to reach $ 1.7 trillion in 2023.

This rapid development and adoption of renewable energy sources has reduced reliance on fossil fuels and begun to curb the increase in greenhouse gas emissions, thereby mitigating the impacts of global warming. A regression analysis of 43 most resource-dependent countries from 2000 to 2015 revealed that 1 percentage point increase in renewable energy consumption leads to 1.25% decrease in CO_2 emissions per capita (Szetela, et al., 2022).

Despite these early promising results, the United Nations Environment Program (2022) reported that the current trend points to a 2.8°C increase in global temperature by 2100. A full implementation of Nationally Determined Contributions (NDCs) and additional net-zero commitments are required to stay below 2°C, the political consensus from the Paris Agreement (Gao, et al., 2017). Furthermore, the rapid recovery from the COVID-19 pandemic and the setbacks from the Russian invasion of Ukraine have significantly challenged fuel selection, thereby hindering global access to energy (IEA, 2022). To adapt to this changing landscape, major players of the oil and gas industry are either integrating low-carbon initiatives into oil production or expanding beyond oil production to clean energy technologies.

Renewable Energy Targets of Major Oil and Gas Companies (IRENA, 2021), (ADNOC, 2023)

Oil and Gas Company	Renewable Energy Target, Deadline
British Petroleum PLC	50 GW, 2030
ENI S. P. A	15 GW, 2030 and 55 GW, 2050
Equinor ASA	4-6 GW, 2026 and 12-16 GW, 2035
Royal Dutch Shell PLC	$ 3 billion annual investment, 2030
Total Energies SE	35 GW, 2025
ADNOC (with TAQA & MUBADALA)	100 GW, 2030

In 2022, the Middle East witnessed a 12.8% increase in renewable energy capacity (3.2 GW) (IRENA, 2023), with the UAE ranking third for renewable energy deployment. The country boasts of a 3 GW renewable energy capacity, with an ambitious target to generate 50% of its energy from clean sources by 2050. Besides major projects such as the Mohammed bin Rashid Al Maktoum Solar Park, one of the largest solar projects worldwide, the UAE demonstrates its commitment to sustainable energy production by investing in feasibility studies for other renewable energy sources. In 2017, ADFEC initiated a 5 MW geothermal project in Masdar City. The $ 25 million project involves a 95°C closed loop geothermal system with two 2.5 km deep wells. While serving the cooling needs of nearby communities, these wells provide reference data for major research and future development (RG Thermal Energy Solutions, 2013). Furthermore, in March 2023, ADNOC Drilling signed a Memorandum of Understanding with MASDAR to invest in the development of geothermal energy in the UAE and globally (MASDAR, 2023).

Underground heat is a source of renewable and sustainable energy, with the potential to meet global primary energy needs without producing any greenhouse gases. The outermost 10 km of the earth's crust along contain about 1.3×10^{27} J, which can sufficiently supply energy globally for almost 217 million years (Lu, 2018). Geothermal energy projects therefore have a significant role to play in the global energy transition. Representing only 0.5% of the global installed renewable energy capacity as of 2021, the geothermal energy technology is considered to hold an immense potential for growth. Indeed, unlike solar, wind, ocean, and some hydro plants, geothermal is a reliable and continuous source of energy, available round the clock. This makes the latter source attractive for future sustainable energy portfolios. Geothermal energy development has also come under the spotlight recently as a solution of choice give the vast expertise of oil and gas industry professionals with well-completion techniques drilling techniques.

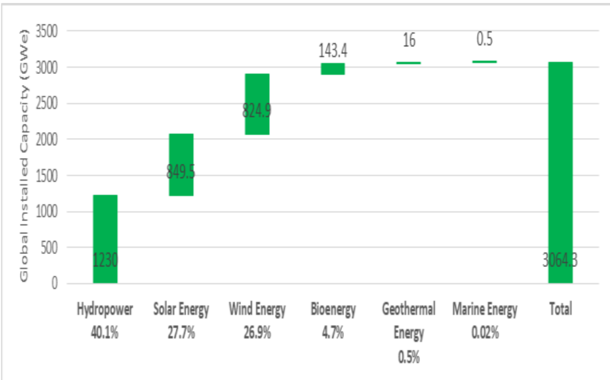

Figure 1. Total Installed Global Renewable Electricity Capacity 2021 (IRENA and IGA, 2023)

Geothermal energy, although uninterrupted, its use in the different applications is predominately dependent on the geothermal source temperature. Temperatures above 150°C are better to be used in electricity production and for fuel production. Although lower temperatures of about 95°C may be used to generate electricity using binary plants, they are often developed to address heating and cooling requirements,

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for better productivity and cost-efficiency (Dincer & Ezzat, 2018).

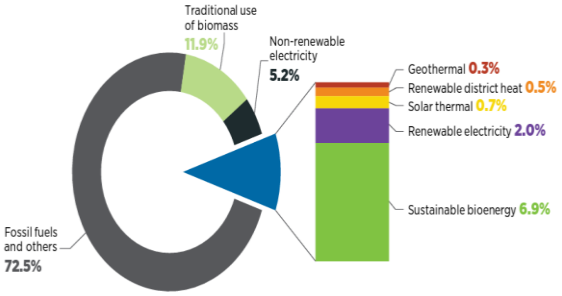

Figure 1. Shares of energy sources in final energy consumption for heating and cooling, 2019

Another drawback to the development of geothermal energy globally is the required proximity with the target market. Due to the high cost of insulation required to transport the resource across long distances, cost-effective geothermal systems for heating and cooling must be set up near the targeted consumer factories or accommodations. That notwithstanding, the development of new combined renewable technologies has opened avenues for the conversion of geothermal output into chemical energy types such as green hydrogen, which can then be stored or easily transported (Osman Awaleh, et al., 2022).

<u>Geothermal Energy Development and Profitability</u>

<u>Resource Evaluation</u>

Underground heat migrates to the surface everywhere around the globe, especially on the edge of tectonic plates (Hamm & Metcalfe, 2019). Located on the edge of the Arabian tectonic plate with the major Dibba fault stretching into its territory, the United Arab Emirates presents a place of interest for geothermal exploration. Five fault categories are identified in Figure 5 (left): the N-S trend (green ellipse) which stops along the ENE trend (move ellipse), which in turn dissipates stresses along the NW-SE (red ellipse), the NE (blue ellipse) trending faults (lineaments) which also transfers stresses along the NW and the NNW (yellow ellipse) trending faults.

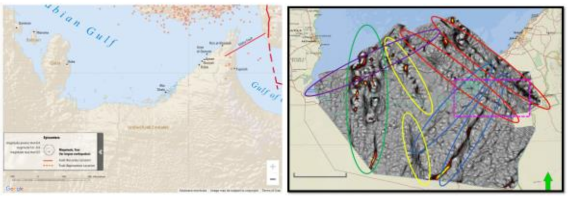

Figure 1. United Arab Emirates – Tectonic Plate Boundaries (Environment Agency - Abu Dhabi, 2023) and Main Fault Zones in Abu Dhabi Emirate (Noufal, et al., 2016).

According to the Maximum Entropy model used to draw up a global geothermal suitability distribution based only on the most important parameters, the warmest regions in the United Arab Emirates sit between the balanced and optimal threshold entropies, with the more suitable regions located in the north-eastern half of the country (Coro & Trumpy, 2020). These results were further supported by an assessment of potential areas of geothermal energy utilization which revealed that the current geothermal resources across thirteen Middle East countries (MECs) are mostly in medium (100–150 °C) and low (< 100 °C) enthalpy reservoirs (Amoatey, et al., 2021). A more localized assessments of two locations with three hot springs – Green-Mubazzarah & Ain Faidha and Ain Khatt (AK) – revealed similar results with potential interconnectivity of GM-AF hot springs at depth. The reservoir temperatures were estimated using magnetic and gravity modelling - 273 gravity stations and 603 magnetic stations for Green-Mubazzarah and Ain Faidha (GM–AF) springs in Abu Dhabi, and 65 gravity stations and 109 magnetic stations for Ain Khatt in Ras Al Khaimah (Saibi, et al., 2022).

Table 1. Estimated Reservoir Temperatures of studied hot spring locations in UAE

Location	Surface Temperature	Reservoir Temperature
Green-Mubazzarah and Ain Faidha (GM–AF)	32 °C to 49 °C	151 °C
Ain Khatt (AK)	39 °C	*Figure 112.* °C

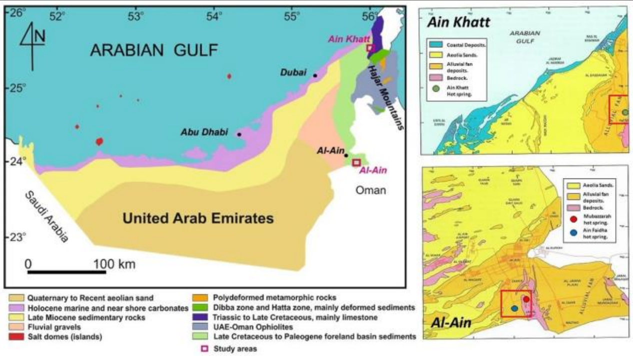

Figure 4. Geological map of the UAE showing the locations of the studied geothermal fields, together with the gravity and magnetic survey locations. Green-Mubazzarah–Ain Faidha hot springs are in Al-Ain city and Ain Khatt in Khatt city

Due to the several underground parameters involved, the methods of estimation of energy stored in geothermal reservoirs may be flawed, leading to an overestimation (Franco & Donatini, 2016). The possibility of drilling into non-transmissive reservoirs poses a considerable risk to geothermal development, thereby imposing the integration of uncertainty in simulations. The accuracy and detection limits of the characterization methods are critical for their applicability in geothermal reservoirs. Some are limited with wellbore diameters, while others might provide large-scale information about fractures (Aydin & Temizel, 2022). While several pre-deployment resource assessments still rely on the simple Monte Carlo simulation to allow for uncertainty in the model parameters (rock permeability, and the magnitude and location of the deep-up flow sources), advanced numerical modelling have helped to evaluate geothermal resources with more accuracy using simulators such as Waiwera geothermal simulator (Dekkers, et al., 2022). One way to control this

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uncertainty is by repurposing existing oil wells drilled into reservoirs with ascertained porosity and permeability levels.

Exploration and Drilling

To harness the greater available heat underground, wells need to be drilled up to depths with higher temperatures. Around the ductile zone in the earth's crust where formation fluid exists in the supercritical state (pure water reaches 374 °C and 221 bar), geothermal production yields remarkably high efficiencies (Reinsch, et al., 2017). Unfortunately, the cost and risk of deep drilling increases with the depth, owing to problems such as equipment choice, poor cement jobs, drilling rate and plan, time management, and lost circulation (Denninger, et al., 2015). In locations with low to medium enthalpy level reservoirs, the financial value of the overall power generated may not be sufficient to make up for the costly and lengthy exploration phase of new geothermal projects. While innovative drilling method that use jets, laser beams, and other thermal-shock failure phenomena induced at the bottomhole (Naganawa, et al., 2017) to mitigate some of the drilling challenges and enable access to higher enthalpies and temperatures, most of aforementioned problems have been faced and addressed by R&D teams within the century-old oil and gas drilling industry. While geothermal energy experts continue to engage with peers from the oil and gas industry for transfer of savoir-faire, Oil and gas companies with extensive experience and capabilities for drilling into high-temperature and pressure reservoirs are looking to geothermal energy solutions as an avenue for growth. To further mitigate these costs of drilling, depleted oil wells drilled into water-flooded reservoirs may be used to produce underground heat. By integrating the accomplishments and key challenges faced from projects that converted hydrocarbon production in geothermal renewable energy, Santos et al. demonstrated that utilizing repurposed oil and gas wells can lower the levelized cost electricity generation by at least 11% (Santos, et al., 2022).

Geothermal Plant Installations – Types, Efficiency, and Profitability

Geothermal installations for electricity production can be categorized into three main types: dry steam, flash steam, and the binary cycle. All three types rely on the same principle of power production: a fluid in gaseous state operates a turbine coupled with a generator to produce electricity. They differ primarily in their wellbore fluid characteristics, their steam extraction process, and their efficiencies.

Typical Characteristics of the different geothermal plant types (IRENA and IGA, 2023) (Moon & Zarrouk, 2014)

Type	Well Fluid State	Min Well Fluid Temperature (°C)	Reservoir Enthalpy Range (kJ/kg)	Overall Conversion Efficiency (as a function of enthalpy, h)
Dry Steam	Steam	150	800-2800	8.7007ln(h) - 52.335
Flash Steam	Steam + Hot Water	150	Single: 800-2800 Double: 750-1900	Single: 8.7007ln(h) - 52.335 Double: 10.166ln(h) - 61.680
Binary Cycle	Hot Water	70-80	0-1010	6.6869ln(h) - 37.930

In 2014, Dry Steam technology represented 23% of the global geothermal capacity, generating a total of 2863 MW from 63 operating plants (Anderson & Rezaie, 2019). In this technology type, dry steam produced from the geothermal well directly rotates the turbine. In the Flash Steam system, which is the most common worldwide, the fluid produced from the well is two-phased, and the steam which operates the turbine is extracted from this well bore fluid through a process called flashing. This extraction process may be repeated several times to produce more steam and improve the efficiency of the installation. In the binary cycle system, heat from the primary wellbore fluid is transferred to a secondary fluid with a lower boiling point than water. The secondary fluid vaporizes to steam and rotates the turbine and generator. The binary system is mostly used in cases where the wellbore temperatures are too low to produce enough steam for electricity generation.

RESEARCH METHODOLOGY

Research Design and Approach

To focus on the most effective energy solutions and initiatives, governments and their stakeholders exploit the findings of scientific research and sharpen their approach and commitments to energy transition. This research aims to provide such relevant and informed recommendations.

Methodological Choice – Mono-method Quantitative

The **mono-method quantitative** analysis shall collect well and reservoir characteristics to evaluate the geothermal potential and cost-efficiency of projects. By focusing on mature oil wells within the UAE, the study shall use the **case study** strategy to let the data inform the local economic opportunities for geothermal repurposing. The elements of the population for this study are mature and depleted onshore production wells drilled into water-drive reservoirs across the UAE. The population comprises several groups (oil and gas fields) that may exhibit homogeneity in terms of geographical proximity and reservoir characteristics. The onshore oil fields are mostly located in the southwest while the onshore gas fields are found in the northeast.

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Table 1. List of major oil and gas fields

Fields (Strata)	Date of Discovery	Emirate
Murban-Bab	1958	Abu Dhabi
Bu Hasa	1962	Abu Dhabi
Asab	1965	Abu Dhabi
Northeast Bab (Dabbiya, Rumaitha, & Shanayel)	1983	Abu Dhabi
Sahil	1967	Abu Dhabi
Shah	1966	Abu Dhabi
Sajaa	1980	Sharjah
Margham	1981	Dubai

Surveys

While drilling oil wells, formation characteristics are measured and recorded. This data shall be collected through **questionnaires** submitted to operators of oil wells in mature fields. To provide reliable insight on the geothermal potential of oil wells, 150 questionnaires shall be sent out and at least 70 % (105 wells) shall be analysed.

Data Analysis Techniques and Tools

Using quantitative data analysis methods, **inferences** about the geothermal potential of each well shall be drawn from the characteristics of the well itself and the reservoir into which it is drilled. The geothermal potential shall be used to compute the four financial indicators selected for the study (Net present value, Internal rate of return, Payback period, Return on investment).

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Limitations

- The study assumes that water cut of the well is constant throughout the life of the well whereas, the water cut increases as the well ages. This implies that the overall water production rate, hence heat content and consequently revenues from geothermal valorisation are higher than evaluated, ceteris paribus.
- The study assumes that the costs of drilling the well at the first installation date will be equal to that of drilling a new well today for geothermal development. However, the costs of drilling two wells, albeit within the same vicinity, can hardly be estimated with such accuracy.
- The study does not take into consideration the impact of social resistance to change on the overall efficiency of geothermal plants. A qualitative analysis of how stakeholders' readiness to welcome change affects the implementation of geothermal repurposing will be a fitting follow up topic for this study.

RESEARCH FINDINGS & DISCUSSION

The analysis of the data collected from oil production wells in onshore fields is aimed at answering the research question raised in the first chapter. In this chapter, the well data is analysed to evaluate the economic benefits of coproduction and repurposing, in comparison to those of new geothermal wells. The economic assessment parameters for geothermal repurposed wells (NPV, IRR, payback period, and ROI) are evaluated from primary well data collected through surveys, and secondary data from previous research. These reference parameters for new geothermal wells are evaluated from the secondary data on two geothermal wells drilled and currently in operation. A discussion follows to investigate the hypothesis that repurposing oil wells is more cost-efficient than drilling new geothermal wells. The reliability and sensitivity of the data shall be presented.

Data Analysis

Assessment of Geothermal Repurposing Potential - Screening

Out of 150 questionnaires sent to well operators, 135 were completed and received. The well data gathered from respondents is presented and analysed below. The screening of wells suitable for geothermal repurposing shall be done following the layers of criteria discussed in chapter 2.

Recoverable Resource and Capacity

Temperature

The fluid temperature at surface for the studied wells varies as per below distribution. The study wells have an average temperature of 114.76 °C with a standard error of ± 0.86 °C. Over 98.5% of the surface temperatures for the studied wells were below 150 °C, confirming the expectation that most wells in the Middle Eastern region have low to medium temperatures.

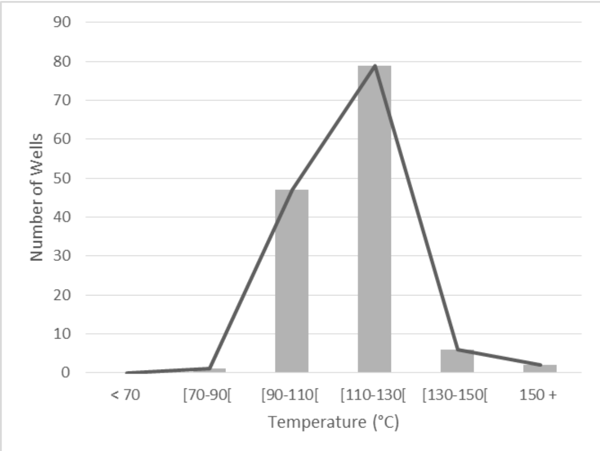

Figure 5. Distribution of Study Wells by Temperature

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Distribution of study wells by temperature

Screening Criteria	Mean	Standard Error	Standard Deviation	Kurtosis	Skewness	Min	Max
Surface Temperature	114.76	0.862	10.018	2.395	0.634	80.36	150.36

Water Production

The water production was calculated from the two primary parameters (production rate (Question 4) and water cut (Question 5)) for the studied wells varies as per below distribution. All the wells showed a lower water cut than the average economic water cut of 95.5% (Question 11), hence this study considers co-production rather than a complete conversion to geothermal production. The 135 study wells showed an average water production rate of 365.20 bpd and a standard error of 9.03 bpd.

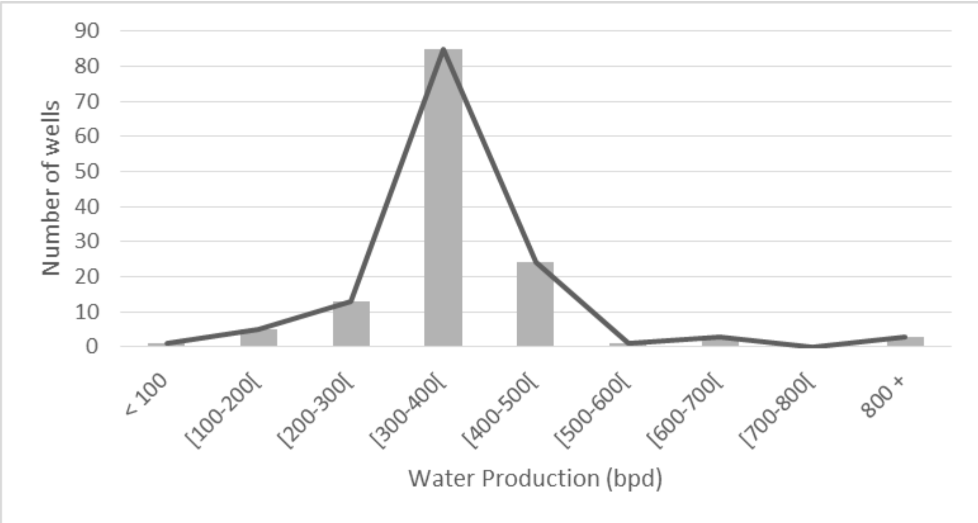

Figure 6. Distribution of Study Wells by Water Production

Table 2. Distribution of study wells by water production

Geothermal System Efficiency

Based on the classification summarized in Table 3 and the Lindal Diagram, the temperatures and enthalpies of the studied wells are too low for Flash or Dry Steam Geothermal power plants, and for Hydrogen production. The proposed applications are the binary cycle and other direct-use applications.

The inlet enthalpy for each well is calculated as a product of the specific heat capacity and the difference between surface temperature and ambient temperature. The system efficiency is then calculated from enthalpy using the formula proposed by Moon and Zarrouk (2014).

$$\eta = 6.6869 \times ln(h) - 37.93$$

$$h = c_w \times (T_1 - T_2) + \frac{P_w}{\rho_w}$$

Where:

η *is the system efficiency*

h *is the inlet enthalpy*

c_w *is the specific heat capacity of produced water*

T_1 *is the temperature of the produced fluid at surface*

T_2 *is the temperature at the discharge of the heat exchanger*

P_w *is the pressure of produced water after separation*

ρ_w *is the density of water produced from the well*

Based on the density of water produced (Survey Question 6) which yielded an average of 8.56 ppg (with a standard error of 0.017 ppg), the specific heat capacity was estimated at 4.005 kJ/kg/K (Cox & Smith, 1959). The discharge temperature T_2 was estimated at 27.9 °C. This is the average ambient temperature in Abu Dhabi calculated by studies of the local climate zone (Manandhar, et al., 2020). Due to the transportation of produced fluid, and the separation of crude from formation water in surface pipelines, pressure is expected to drop from the wellhead to the inlet of the geothermal system. Moreover, the partial pressure of the formation water to be used is only a portion of the leftover pressure. To account for these losses, the pressure enthalpy $(\frac{P_w}{\rho_w})$ is not included in the inlet enthalpy used to calculate the system efficiency. Eight (8) wells with enthalpies lower than 290.68 kJ/kg yielded negative system efficiencies and were excluded from the rest of the study.

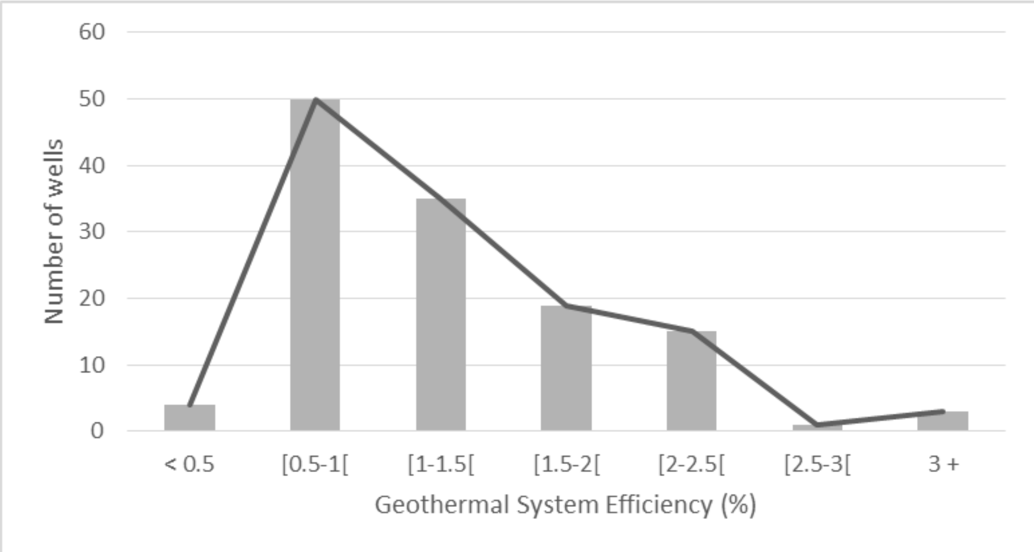

Figure 7. ***Distribution of Study Wells by System Efficiency***

Table 7. Distribution of study wells by system efficiency

Screening Criteria	Mean	Standard Error	Standard Deviation	Kurtosis	Skewness	Min	Max
System Efficiency	1.26	0.057	0.644	1.333	1.026	0.005	3.500

Installed Capacity

After excluding the 8 wells with low enthalpies, the installed capacity was calculated for the remaining 127 wells using below formula:

$$P_e = \eta_e \times q_w \times \rho_w \times h$$

Where:

$$P_e \text{ is installed capacity of the geothermal system}$$
$$\eta_e \text{ is the efficiency of the system}$$
$$\rho_w \text{ is the density of produced water}$$
$$q_w \text{ is the water production rate}$$
$$h \text{ is the inlet enthalpy}$$

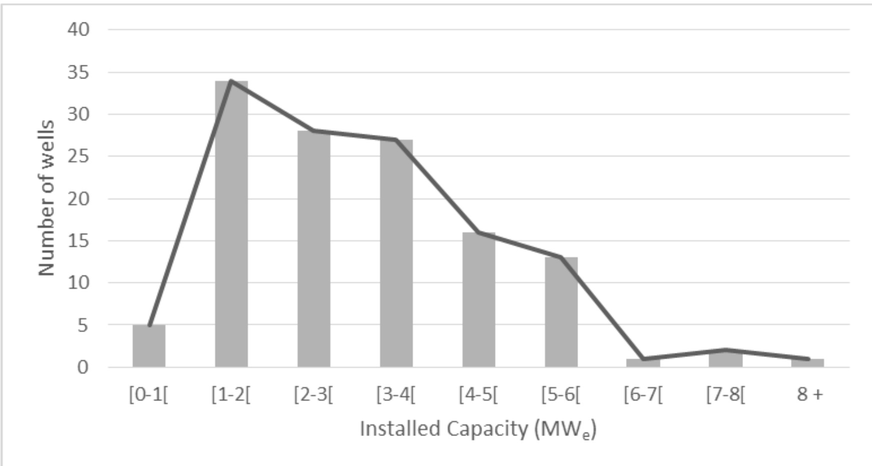

Figure 8. Distribution of Study Wells by Installed Capacity

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Table 8. Distribution of study wells by installed capacity

Screening Criteria	Mean	Standard Error	Standard Deviation	Kurtosis	Skewness	Min	Max	Sum
Installed Capacity (MW)	3.15	0.149	1.677	3.717	1.322	0.01	11.34	399.92

Discussion

Due to low and medium temperatures, and the pressure losses incurred upon separation of the water from produced fluid, the inlet enthalpies for the geothermal systems are in the range 210-490 kJ/kg/K. This results in overall low efficiencies of energy conversion, with an average of 1.26 % and a standard error of 0.06%. On average, the geothermal systems to be installed at each well will have a capacity of 3.15 MW_e. Despite the low individual capacities, the results show a potential 399.92 MW_e, a considerable addition to the existing energy supply portfolio.

Available Market and Operating Time

Available Energy Market

The UAE hosts a growing population and economy with increasing energy demands. The national energy consumption is estimated at an average of 131,561.41 GWh for the period of 2017 to 2021. The additional electricity production capacity from geothermal repurposing is expected to be connected to the national grid and contribute to the national portfolio.

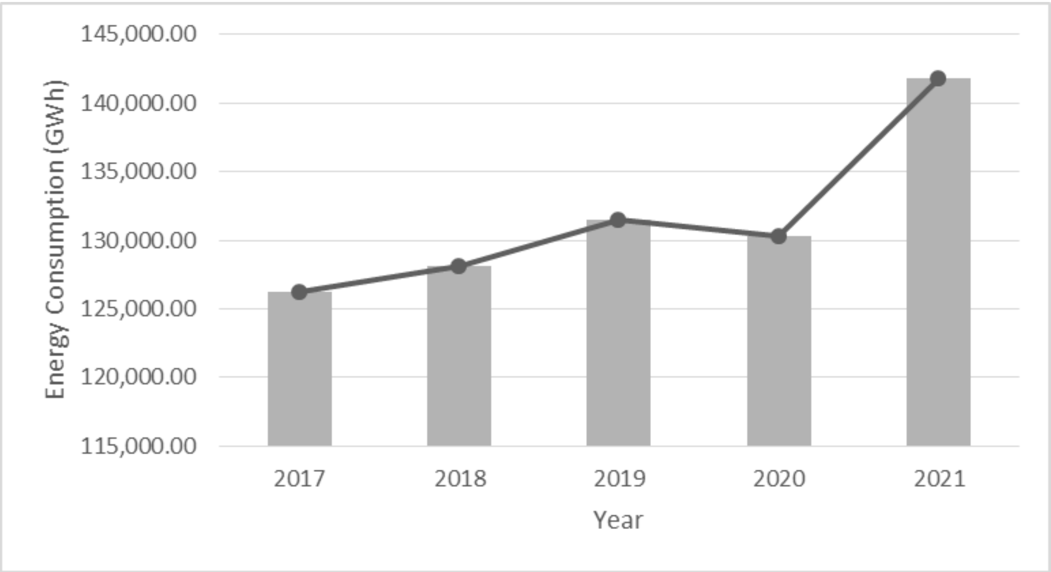

Figure 9. UAE Energy Consumption Trend (2017-2021) (CEIC Data, 2021)

Because geothermal energy source is continuous, the supply from these plants is given priority over other supply sources such as hydrocarbon power plants that have depleting reserves. All the energy produced shall therefore be used to address the growing market discussed above.

Remaining Well Lifetime

The lifetime of geothermal energy production for each well represents the remaining period of well operation (Survey Question 3) until the scheduled plug and abandonment operation. The remaining lifetime of the 127 wells varies as below.

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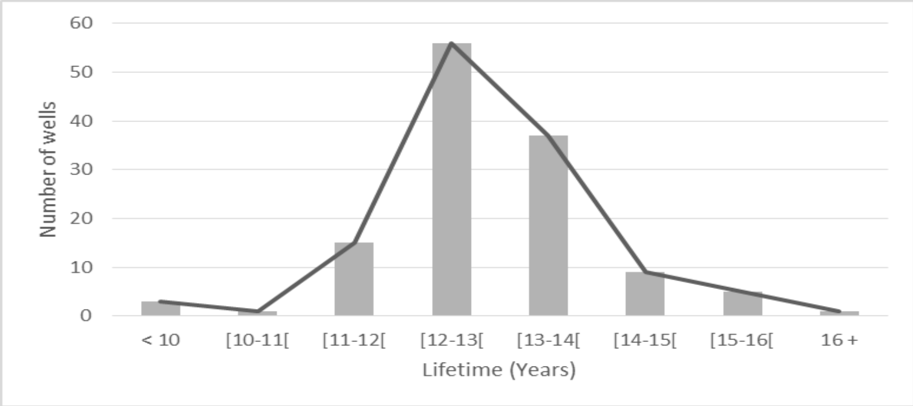

Figure 10. Distribution of Study Wells by Lifetime

Table 9 Distribution of study wells by remaining well lifetime

Screening Criteria	Mean	Standard Error	Standard Deviation	Kurtosis	Skewness	Min	Max
Remaining Lifetime (Years)	12.79	0.120	1.353	8.984	-1.806	6.051	16.18

Discussion

The operating time is calculated by adjusting the lifetime to account for O&M downtimes. A one-month downtime was considered every two years to account for the repair of geothermal systems and scheduled well workover operations. Hence operating time was calculated as follows:

$$Operating\ time\ (t) = lifetime(1 - \frac{1}{24})$$

Hence, the average operating time for the geothermal units is 12.30 years, with a standard error of 0.12 years. As expected, this operating time is lower than that of systems with newly drilled wells.

Installation, Maintenance, and Abandonment Costs

The overall costs were evaluated as a sum of installation costs (the electric system and pipeline requirements for geothermal systems), the operation and maintenance costs, and the eventual abandonment cost for each well.

Installation Costs

The installation cost of the geothermal surface system to be connected at surface is evaluated based on the installed capacity and the distance of the well from the existing electricity grid (Survey Question 12). The installation costs vary as below

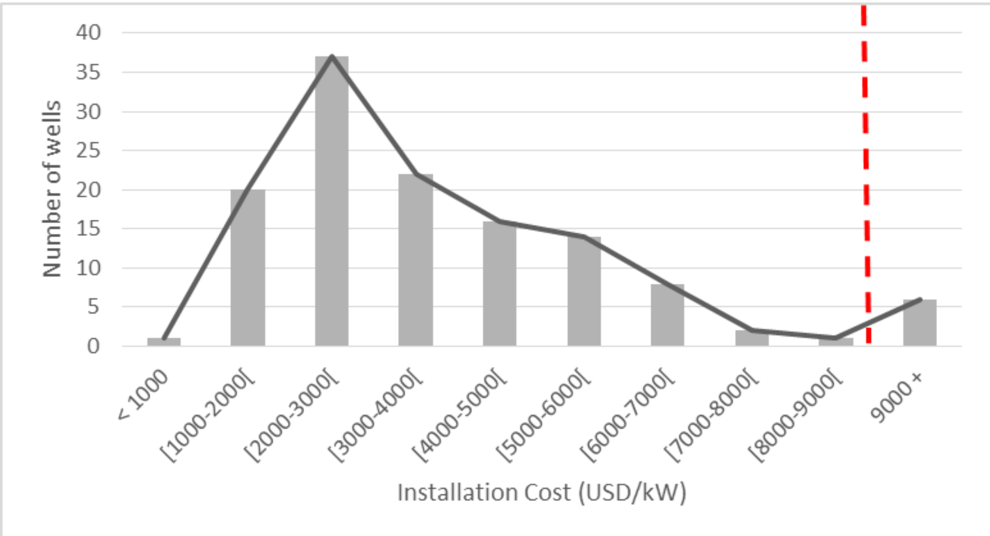

Figure 11. Distribution of Study Wells by Installation Cost

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The installation costs are reported per unit kW installed to compare with industry standards previously illustrated in Figure 8. As reported by IRENA (2017), the maximum installation cost for geothermal systems involving newly drilled wells is 9000 USD/kWh.

Considering that the current study only involves installation of surface system, any installation costs above 9000 USD/kWh are considered non-competitive and excluded from the rest of the analysis. Six wells showed installation costs higher than the cut-off and were excluded.

The analysis of the remaining 121 wells showed below results. The installation costs vary significantly from one well to the next, and the standard deviation equals about half of the mean.

Table 10 Distribution of study wells by installation costs

Screening Criteria	Mean	Standard Error	Standard Deviation	Kurtosis	Skewness	Min	Max
Installation cost (USD/kWh)	3530.13	149.665	1646.319	-0.128	0.766	1142.21	8400.59

Operation and Maintenance

Out of 135 wells, only 24 had O&M costs referenced (Question 13). To proceed with the analysis, O&M costs of the studied wells was estimated using an exponential function of installed capacity (Hackstein & Madlener, 2021).

$$c_{O\&M} = 20 \times e^{(-0.0025 \times (P_e - 5))}$$

Where:

$$P_e \text{ is installed capacity of the geothermal system}$$
$$c_{O\&M} \text{ is the O\&M cost}$$

The operation costs show little variation from one well to the next, with an average of 20.09 USD/kWh, and a standard error of 0.007 USD/kWh.

Discussion

The average installation cost of 3530.13 USD/kW already suggests lower investment as compared to the average installation costs geothermal systems with newly drilled wells. This highlights the immediate benefits of eliminating drilling and completion costs.

Economic Assessment and Cost Efficiency

Net Present Value

The cash flows are calculated as proceedings from the sales of energy produced throughout the operating time of the geothermal units. Hence the net present value can be calculated as follows:

$$NPV = \sum_{y=1}^{t} \frac{((p_e \times t \times P_e) - c_{O\&M})_y}{(1+r)^y} - Initial\ Investment$$

Where:

$$r \text{ is the annual discount rate}$$
$$p_e \text{ is the price of a unit kWh of electricity supplied}$$

The cost of the electric kWh in Abu Dhabi varies for different customer categories (Abu Dhabi Distribution Co., 2023). However, the average cost p_e used for this analysis is 0.293 AED/kWh (0.08 USD/kWh). The annual discount rate r in the UAE is at 5.4 % (CEIC, 2023).

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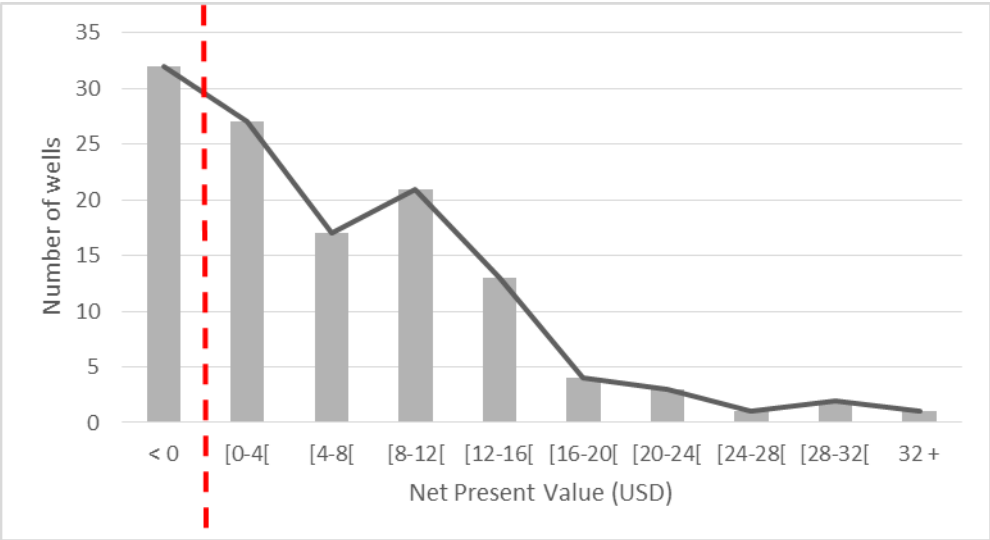

Figure 12. Distribution of Study Wells by Net Present Value

Out of 121 wells, the geothermal units for 32 wells returned a negative net present value. They are therefore not considered a good investment and will be excluded from the next stage of the analysis. This is explained by the fact that, unlike new geothermal wells, repurposed wells may not have sufficient remaining lifetime to break even before the well is plugged and abandoned.

The analysis of the net present value for the 89 remaining wells is summarized below.

Table 11 Distribution of study wells by net present value

Screening Criteria	Mean	Standard Error	Standard Deviation	Kurtosis	Skewness	Min	Max	Sum
Net Present Value (MM USD)	9.096	0.783	7.383	2.922	1.411	0.201	38.189	809.545

LCOE

The Levelized cost of energy is calculated as a ratio of the net present value of costs to the net present value of the energy output. The results are summarized below.

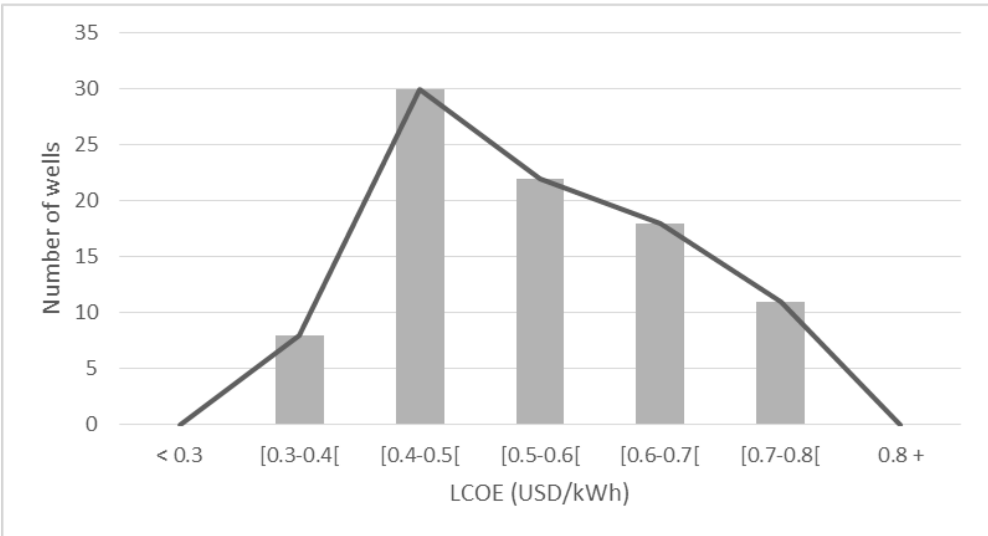

Figure 13. Distribution of Study Wells by LCOE

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Because the units with negative net present value have been discarded, all the LCOEs are below the sales price of electricity within the available market.

Considering the global average LCOE of 0.056 USD/kWh (IRENA, 2022), the average LCOE of 0.054 USD/kWh for the study wells is considered competitive. The 38 wells with LCOE lower than 0.050 USD/kWh are of particular interest and will support initiatives to provide more affordable energy.

Table 12 Distribution of study wells by LCOE

Screening Criteria	Mean	Standard Error	Standard Deviation	Kurtosis	Skewness	Min	Max
Levelized Cost of Energy (USD/kWh)	0.0546	0.0013	0.0122	-0.8321	0.3958	0.0328	0.0788

Break Even Point

The breakeven year is calculated as a ratio of installation cost to annual cashflow. The results are summarized below

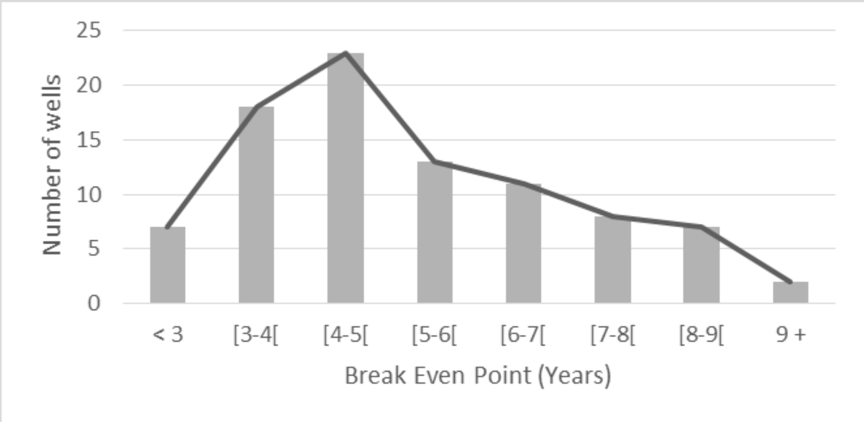

Figure 14. Distribution of Study Wells by Break-Even Point

Table 13. Distribution of study wells by break-even point

Screening Criteria	Mean	Standard Error	Standard Deviation	Kurtosis	Skewness	Min	Max
Break Even Point (Years)	5.235	0.193	1.824	-0.502	0.548	2.168	9.461

RR

The IRR is calculated as the annual discount rate at which the net present value is zero. The IRR for the 89 wells varies as follows.

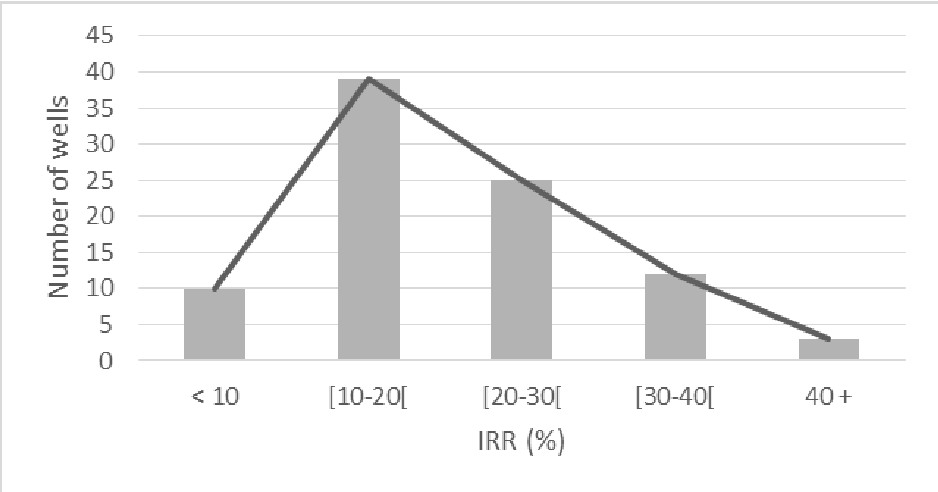

Figure 15. Distribution of Study Wells by IRR

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Table 14. Distribution of study wells by IRR

Screening Criteria	Mean	Standard Error	Standard Deviation	Kurtosis	Skewness	Min	Max
Internal Rate of Returns (%)	20.17%	0.92%	8.64%	0.275	0.687	6.98%	46.01%

ROI

The return on investment is calculated as a ratio of the net present value on project investment. The ROI for the 89 wells varies as follows.

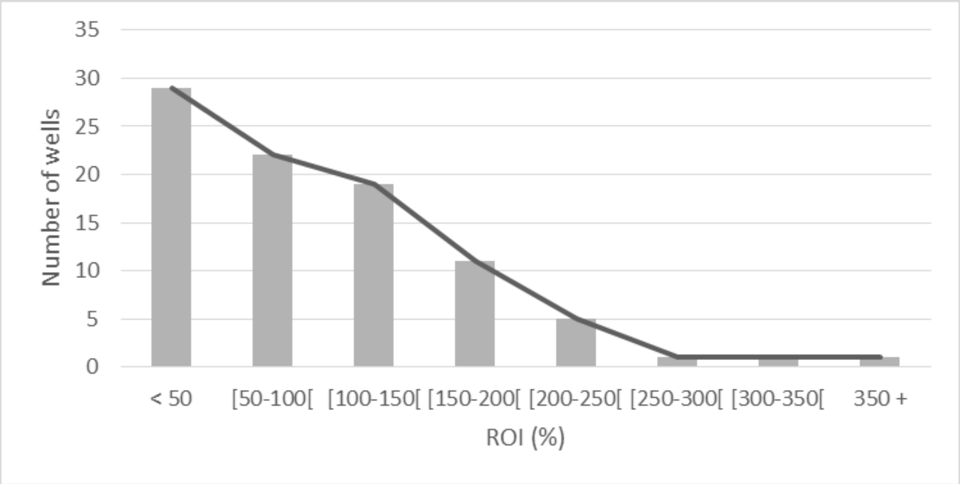

Figure 16. Distribution of Study Wells by ROI

Table 15. Distribution of study wells by ROI

Screening Criteria	Mean	Standard Error	Standard Deviation	Kurtosis	Skewness	Min	Max
Return on Investment (%)	97.23	8.004	75.507	1.6681	1.1141	2.13	366.00

Results and Discussion

Sensitivity Analysis and Risk Assessment

After screening through all the criteria, the results of the 89 wells are summarized in the table below. They are considered potent opportunities for the following reasons:

- Installation costs within the range of costs for similar systems within the industry
- Positive net present value
- LCOE lower than the current sales price of electricity within the target market

Skewness

Of all the indicators, only the LCOE exhibits fair symmetry. While the Break Even Point and IRR are moderately positively skewed (0.5<skewness<1), the NPV and ROI are highly positively skewed (skewness>1). This indicates that the performance of the geothermal units is not evenly distributed across the wells. For each of the parameters, the mean value is higher than the mode. For the NPV and ROI, the mean is therefore not a good indicator of central tendency.

Kurtosis

The excess kurtosis of the LCOE and Break Even Point are negative, hence, these distributions are Platykurtic: outliers (extremely good or bad) are unlikely. The excess kurtosis of the IRR is positive, and not too far from a normal distribution (excess kurtosis of 0). However, the excess kurtosis of NPV and ROI are greater than 1. This indicates a high risk around the right tail of each parameter: outliers (extremely good or bad) are likely.

Standard Deviation

Apart from the LCOE, all other indicators exhibit a standard deviation that equals about half of the mean. This suggests that the datasets are spread out, away from the mean. All data points at over 3 standard deviations above or below the mean are considered

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outliers. Based on this fact, three wells were excluded for generating outlier NPVs, and one well was excluded for generating an outlier ROI. The results of financial indicators for the remaining 85 geothermal systems are summarized below.

Table 16. Sensitivity Analysis of the Financial Indicators for the selected wells

Screening Criteria	Mean	Standard Error	Standard Deviation	Kurtosis	Skewness	Min	Max	Sum
Net Present Value (MM USD)	8.029	6.010	5.542	-0.614	0.447	0.201	21.447	682.433
Levelized Cost of Energy (USD/kWh)	0.055	0.001	0.012	-0.901	0.459	0.037	0.079	-
Break Even Point (Years)	5.363	0.191	1.764	-0.524	0.601	2.758	9.461	-
Internal Rate of Returns (%)	19.213	0.812	7.489	-0.705	0.317	6.977	35.996	-
Return on Investment (%)	87.783	6.668	61.477	-0.523	0.492	2.132	245.596	-

Comparative Analysis

The UAE boasts of two operational geothermal wells drilled and completed at Masdar City. The parameters for these wells are inferred from the case study report of the energy company RG-TES (RG Thermal Energy Solutions, 2013) and the released parameters upon confirmation of successful breakthrough with geothermal energy production (Benny, 2023). The two wells are operated to address the cooling needs of the Masdar City community. Because the provision of cooling services may involve different model, the energy units were assumed to be sold at the price of electricity in Abu Dhabi, to set a basis for comparison with repurposed wells. Below table compares the average indicators for the 85 selected wells to the indicators of the two geothermal newly drilled wells.

Table 17. Financial Model Results for New Geothermal and Geothermal Repurposing

Parameter	Units	New Geothermal	Geothermal Repurposing
LCOE	$/kWh	0.062	0.055
Internal Rate of Return	%	9.40	19.21
Net Present Value	$M	10.59	8.03
Breakeven Year	Years	9.51	5.36
ROI	%	42.39	87.78

The LCOE of geothermal co-produced from hydrocarbon wells is lower than that of geothermal from new wells as expected. This is mainly attributed to the elimination of drilling and completion costs which are estimated at 40% of total investment in new geothermal projects (Gul & Aslanoglu, 2018). However, due to their longer lifespan, new geothermal wells produce more energy to offset the higher costs. Hence the consequent drop in LCOE is only of 11.29%.

The IRR of geothermal co-produced from hydrocarbon wells is lower than that of geothermal from new wells. This suggests that geothermal co-produced from hydrocarbon wells has a greater margin of cost of capital, hence, a wider group of investors to attract. New geothermal wells are limited by the IRR and cannot afford any cost of capital higher than 9.40%.

The Net Present Value of geothermal co-produced from hydrocarbon wells is lower than that of geothermal from new wells. Again, this is indicative of the fact that despite the higher costs, new wells live long enough to generate gains that offset the costs and surpass the gains of geothermal co-produced from hydrocarbon wells. It is worthy of note

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however that the average lifetime of co-produced wells is only half that of new wells. Hence the drop in NPV is only 2.56 million USD (24%) for over 12 years (48%) reduction of the project's lifespan.

The Break Even Year of geothermal co-produced from hydrocarbon wells is lower than that of geothermal from new wells by about 44%. This is close to the difference in lifetime. Due to their relatively shorter remaining lifetime, co-produced wells must have a short payback period to have positive financial indicators. This also suggests that geothermal from co-produced wells is more attractive for investors who seek quicker returns.

The ROI of geothermal co-produced from hydrocarbon wells is higher than that of geothermal from new wells. The increase in ROI from 42% to 88% indicates that geothermal from co-produced wells is better at using investment to generate high returns than geothermal from new wells.

CONCLUSION

Geothermal is a continuously produced energy type that is expected to play a major role in the energy transition and the global walk to net-zero emissions. However, its development faces several challenges such as the cost and uncertainty associated with exploration, drilling, and completion of wells. Amongst the solutions for mitigation of these costs is the repurposing of existing hydrocarbon wells for geothermal production. This stems from the assumption that eliminating drilling costs improves the economics of geothermal projects. Although this assumption seems obvious from a macro perspective, the reduced lifetime of existing wells may significantly affect their financial performance. Hence, a thorough analysis of the resource, lifetime, and market availability for each project is required to conclude.

Summary of Key Findings

The main objective of the study was to evaluate if repurposing depleted oil wells in the UAE for sustainable geothermal production or co-production is more economically viable than drilling new geothermal wells by comparing five financial indicators: LCOE, Net present value, IRR, Break Even Year, and ROI.

The temperatures of the studied wells were found to be below 150 °C. In addition, the distance of the fields from the main cities makes it challenging to envisage direct use without incurring huge losses. Hence a binary cycle system was selected as the best option to valorise the produced energy.

Out of the 135 wells for which the data was analysed, 8 wells were found to have inlet enthalpies lower than 290.68 kJ/kg/K. Based on the efficiency-enthalpy charts developed by Moon and Zarrouk (2014), these wells do not mean the requirement to host a binary cycle geothermal system with positive efficiency. Hence, they were excluded from the study.

Out of the remaining 127 wells, 6 wells were found to have installation costs higher than 9000 USD/kW – the maximum cost reported from IRENA's analysis of geothermal costs globally (IRENA, 2022).

Out of the remaining 121 wells, 32 wells presented a negative net present value. They were excluded from the next stage of the screening as non-viable options.

Out of the 89 remaining wells, 3 were found to have an outlier net present value (higher than the mean plus three standard deviations). Out of the 86 wells, 1 well was found to generate an outlier ROI (higher than the mean plus three standard deviations).

In summary, 85 wells were identified as potential options presenting viable financial models that can be compared to geothermal projects from newly drilled wells.

The key findings are as follows:

- Geothermal co-produced from the hydrocarbon wells exhibited a 11.29% drop in LCOE for an estimated 40% drop in total project investment when compared to geothermal projects from newly drilled wells.
- Geothermal co-produced from hydrocarbon wells was higher by 9.81% when compared to geothermal projects from newly drilled wells.
- Geothermal co-produced from hydrocarbon wells generated a lower NPV. A drop of only 2.56 million USD (24%) was observed for over 12 years (48%) reduction of the project's lifespan.
- Geothermal co-produced from hydrocarbon wells exhibited a shorter payback period by 4.15 years, almost half the payback period of projects from newly drilled wells.
- Geothermal co-produced from hydrocarbon wells generated an ROI of 88%, which is twice that of geothermal projects from new wells.

Recommendations for Policymakers, Industry Stakeholders, and Future Researchers

Recommendations for Industry Stakeholders

- Collaboration between oil and geothermal industry stakeholders to leverage existing infrastructure, knowledge, and expertise. Joint ventures and partnerships can further reduce project costs and risks.
- Allocate resources for geothermal resource exploration and assessment. Conduct thorough geological surveys to identify the most promising areas for geothermal development within the UAE and map against oil fields.
- Invest in research and development to enhance geothermal technology and improve technological efficiency.

Recommendations for Policymakers

- Policymakers should develop and implement financial incentives (subsidies and tax breaks) and support mechanisms (guaranteed power purchase agreements to attract private sector investments) for geothermal energy projects.

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- Set clear and ambitious sustainability targets, including renewable energy capacity goals and emissions reduction targets to guide the adoption of geothermal energy.
- Launch public awareness campaigns to educate citizens and oil-dependent communities about the opportunities of co-production and the benefits of geothermal energy and its role in the UAE's sustainable energy future.

Recommendations for Future Researchers

- Expand on geothermal resource assessments to UAE offshore fields where deeper wells may have reached higher temperatures.
- Focus on advancing geothermal drilling techniques and heat extraction methods to improve the efficiency and cost-effectiveness of geothermal energy production.
- Investigate the effectiveness of policy initiatives and incentives in driving geothermal development and recommend adjustments as needed to maximize their impact.

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