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Review

Power from Geothermal Resources as a Co-product of the Oil and Gas Industry: A Review

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Cite This: *ACS Omega* 2022, 7, 40603–40624

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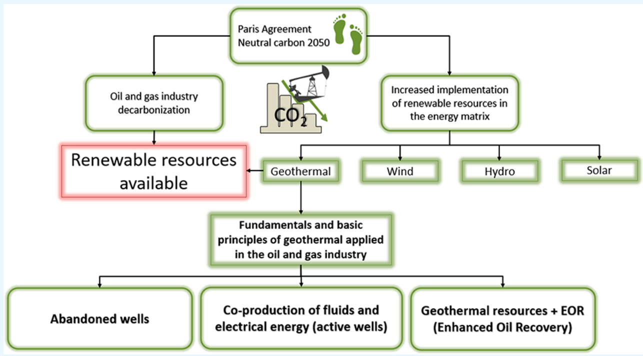

ABSTRACT: The increase in the global demand for energy and fossil fuel dependency is hindering efforts to reduce greenhouse gas (GHG) emissions. Geothermal resources supplement this increase in energy demand with reduced emissions because of their availability, base-load production profile, and climatic independence. Despite these advantages, the development of geothermal energy is limited because of different reasons such as subsurface exploration risk and high upfront capital cost for drilling and facility construction. However, similarities in infrastructure and operations between the oil and gas industry and the geothermal industry can optimize expense and development when exploiting geothermal resources. Thus, in this review, we present recent advances and applications of geothermal power systems in the oil and gas industry starting from the fundamentals and basic principles of geothermal energy and the organic Rankine cycle (ORC). These applications include the use of geothermal resources via abandoned wells, active wells, and paired thermal enhanced oil recovery processes with injection for fluid heating and energy production. Abandoned wells are alternatives that reduce costs in geothermal energy-use projects. The use of geothermal resources via active wells allows the valorization of a resource, such as the production of water, which is considered a byproduct of production activities in an oilfield. The use of thermally enhanced oil recovery processes enhances the energy conditions of fluids produced in the field, improving geothermal systems with fluids at higher temperatures. Finally, an overview is presented of the challenges and opportunities of geothermal energy in the oil industry where the requirement to improve the usage of technologies, such as the ORCs, with the working fluids used in the cycles, is highlighted. Furthermore, the importance of environmental studies and use of novel tools, such as nanotechnology, to improve the efficiency of geothermal energy usage is highlighted.

1. INTRODUCTION

During the first quarter of 2020, the health crisis caused by COVID-19 caused a 3.8% decline in global energy demand compared with the same quarter in 2019.[1,2] However, per the International Energy Agency (IEA),[3] this demand will return to prepandemic levels by 2023 in scenarios where COVID-19 was under control in 2021. Global energy demand might reach close to 29,000 TWh by 2030, thus necessitating a supply of ~33,000 TWh.[3] Fossil fuels will remain the principal source of electricity generation to 2030, thus contributing ~52% of the total global power supply with 38 and 10% contribution from renewable and nuclear energy sources, respectively. Despite the predicted high contribution from fossil fuels, it is estimated that between 2018 and 2030, most fossil fuel-derived power will reduce because it will be replaced by renewable sources. This situation will increase per the Paris Agreement (COP21) and 2021 United Nations Climate Change Conference targets (COP26), which will lead to a maximum increase in average global temperature of 2 °C.[3−5] The industry has a higher primary energy consumption (42%), followed by buildings (30%), transport (17%), and noncombusted sector (11%) globally, and this trend will be maintained for the next 30 years.[6] These projections lead to a scenario where 900 Mt will cause CO_2 emissions associated with power production from 2019 to 2030.[3]

In 2019, it was estimated that 770 million people did not have access to electricity; however, by 2030, it is expected that 660 million people will remain without access to electrical power.[3] Therefore, renewable energy sources should be

Received: July 11, 2022
Accepted: October 11, 2022
Published: October 31, 2022

considered as an option for zones without access to this service. Moreover, in addition to energy efficiency, carbon capture, and storage, it is an important decarbonization pathway to net-zero emissions.[7]

Wind power, solar power, and hydropower are the most examined and extensively deployed renewable energy sources.[8−12] Wind power converts wind's kinetic energy to power using wind turbine systems, comprising rotors with turbines, electric generators, and electronic power converters. Solar power is derived from the Sun and maybe harnessed for electrical generation or direct applications where a heat source is required.[13] Solar power is derived from concentrated solar power or photovoltaic cells. In concentrated solar power, heat or electricity is generated by coordinating an array of mirrors that focus sunlight to heat a solid or fluid to temperatures up to 1,000 °C.[13] Photovoltaic power uses photovoltaic cells, comprising Si compounds, which convert sunlight to electricity.[13] Finally, hydroelectric power is a renewable source that uses hydraulic potential energy differences to generate electricity or mechanical movement.[14] Currently, it is estimated that power generation for wind, hydro, and solar resources will grow from 1272, 4513, and 332 TWh to 2681, 5677, and 846 TWh by 2035, respectively.[15]

However, solar power and wind power have multiple disadvantages. Wind power is an expensive technology that depends on climatic forces that produce a variable and unpredictable electrical output.[16] Furthermore, wind power is challenging to integrate in conventional power grids because of issues related to energy storage.[17,18] Moreover, the remoteness of multiple wind power sources complicates its integration because many favorable locations for producing wind power are far from power grids, and thus additional investment is required in transmission to bring this power to the market.[9] The impact of wind power on the environment is non-negligible. In addition to the noise pollution and landscape considerations of wind turbine operation, they are known to harm fauna such as insects and birds.[10,13] However, it is difficult for solar power to realize its full potential, although the energy from the Sun is sufficient to supply 7900 times the world's energy demand.[13] Similar to wind or hydropower, solar power depends on climatic conditions for sufficient production of electrical power.[19] Solar power depends on solar radiation, diurnal cycles, temperature, humidity, and wind speed.[13,20] The minerals required in the construction phase, as well as the structure of solar and wind energy impact the environment. Moreover, hydropower is critical in the CH_4 emissions for submerged vegetation and flooded lands.[21,22] Geothermal energy does not require technologies that are periodically modified because of climatic changes or the use of minerals with an important environmental impact on their extraction.[23]

It is estimated that 43,000,000 EJ of geothermal energy is stored in 3 km of Earth's surface; it could then be converted to ∼1,200,000,000 TWh of power.[24] This quantity demonstrates the potential of geothermal energy for power generation. Unlike other renewable energy sources, energy supply can be constant and climatically independent.[25] Certain disadvantages in applying geothermal energy are the high cost justified by the exploration and drilling of wells and the uncertainty of identifying sources with high quality, which justify the project's start.[26,27] The application of geothermal energy is not limited to electricity generation. Geothermal heat is harnessed in multiple residential and commercial applications, which use the heat or concentrate the heat as in geo-exchange technologies such as the heating of crude oil to facilitate fluid transportation,[28] heat exchange in the process and service fluids,[29−31] and other applications.[32]

In 2019, geothermal energy contributed 92 TWh of electricity production to global supply, which is expected to increase by 106% by 2030.[3] However, despite its high availability, the contribution of geothermal power represents ∼1% of the global supply.[3] One of the primary challenges in the use of geothermal energy is the considerable investment required in exploration and drilling, for which costs can increase to 50% of a geothermal energy project.[33,34] For developing geothermal power, a well might not have the expected temperatures or fluid rates to support economic production, thus depicting a significant financial risk.[32] However, capital expenditure related to drilling may be eliminated by developing applications that can integrate the oil and gas industry's knowledge, experience, and infrastructure.

In both the oil and gas industry, the temperatures of produced fluids, depending on reservoir conditions, can be classified as medium enthalpy (temperature between 90 and 150 °C) or low enthalpy fluids (temperatures below 90 °C) geothermal resources.[35] Electricity generation is considered to be feasible as long as the temperature of produced fluids is at least 70 °C; otherwise, the resource may only be helpful in direct or geo-exchange applications.[36]

Medium- and low-enthalpy fluids can generate electricity by installing binary cycle power plants. A binary cycle power plant comprises an evaporator, expander, pump, condenser, and heat source.[37−40] Countries, such as Germany,[41] France,[42,43] the United States,[44,45] Indonesia,[46] Austria,[47,48] and Portugal,[49] have used the organic Rankine cycle (ORC), a form of binary cycle power generation technology, which is the primary mechanism for electrical production from geothermal resources. The working principle of the ORC is similar to that of the conventional Rankine cycle. However, rather than water, the working fluid is an organic fluid with a higher molecular mass and a lower boiling point than that of water.[38,39]

Geothermal energy is a power source having relatively low environmental impact such as land transformation[25] and greenhouse gas emissions. On an average, conventional geothermal plants (flash or dry steam) produce 8.2 kg CO_2 MWh^{-1}, whereas solar power, wind power, and hydropower produce 1.1 CO_2, 0.02 CO_2, and 0.8 CO_2 MWh^{-1}, respectively.[50] However, binary power plants produce virtually zero emissions[25] because of their closed-loop configuration in which the fluid is constantly reused, thus avoiding the direct exposure of organic working fluids in the environment. This renewable source has one of the lowest carbon footprints compared with fossil fuel sources and other renewables.[25] Geothermal fluids are reinjected in the reservoir to avoid discharge subsidence (gradual caving in or sinking of an area of land) or dissolved solids.

Moreover, in a world in which the dependency on fossil fuels, such as oil and gas, indicates considerable impact on carbon emissions, coupling geothermal energy with oil and gas operations is a decarbonization alternative. Therefore, the environmental impact of oil and gas operations can be reduced if the energy generation is sufficient to replace fossil fuels such as diesel and natural gas. Moreover, the use of geothermal energy from oil and gas operations will reduce carbon emissions, supply electricity to remote areas, where conven-

https://doi.org/10.1021/acsomega.2c04374
ACS Omega 2022, 7, 40603−40624

tional power grids are difficult to connect, or even be employed in direct heating applications.[51]

The use of geothermal resources has been studied in the oil industry because of its potential.[51] Well production with high water cuts and high temperatures of fluids on the surface has the capacity for energy production in countries such as the United States and China.[31,52,53] Furthermore, the structure of wells in the oil industry facilitates the implementation of projects related to geothermal resources.[52,54] Geothermal energy sources can be improved from operations conducted in the oil industry, such as thermal enhanced oil recovery (TEOR), where the temperature of the fluids in the reservoir increases.[55,56]

However, despite multiple applications proposed to couple the oil and gas industry with energy generation from geothermal resources, knowledge about the potential and real applications worldwide is limited. Therefore, this review highlights the potential application of geothermal energy co-production and examines the current implementations of the technology in oilfields.

This study presents relevant research on the use of geothermal resources in the oil industry and the basic principles that define the relationship between geothermal and fluid extraction in the oil industry; for this purpose, three sections are shown. The first section focused on abandoned wells, which was the first application, where the infrastructure set up by the oil industry was used for a geothermal purpose. The second section shows geothermal resource use in active wells where evaluations are shown together with applications globally. Finally, the joint work of enhanced oil recovery (EOR) processes is presented with the heating of fluids to take advantage of high surface temperatures. This document presents the projects and research related to geothermal energy in the oil industry in detail. The study of the synergy between these fields will allow the use of renewable resources to decarbonize the oil industry.

2. GEOTHERMAL ENERGY: FUNDAMENTALS AND BASIC PRINCIPLES

Geothermal energy is a renewable and alternative source of energy extracted from the heat stored below Earth's surface.[26,57,58] Below Earth's crust, a magmatic layer generates heat because of the continuous decay of radioactive materials such as uranium, thorium, and potassium.[59−61] Heat is transported to the surface because of the crustal movement, caused by convective heat transfer,[58,62] where high-temperature and -pressure conditions cause plastic behavior in the rocks in Earth's mantle. Density differences lead to lighter and hotter portions of the mantle to move upward, heating rocks and water present in Earth's crust to temperatures of >370 °C.[59] Conduction is the primary heat transfer mechanism in Earth's crust[63] caused by interactions between lithospheric plates.[62] Earth's geothermal energy will last for 4−5 billion years, and that heat stored in 10 km of Earth's surface holds heat equivalent to 50,000 times more energy than all of the world's oil and gas reserves.[59] On a yearly basis, 10,000,000 GWh of heat is conducted from Earth's interior to the surface.[58]

A conventional geothermal system comprises a reservoir rock, caprock, heat source, and on some occasions, permeable structures such as fractures.[62] For high enthalpy geothermals, heat sources may include plutonic intrusions. In low-enthalpy geothermals, the flux of heat escaping from Earth's interior with the heat derived from the radioactive decay of crustal minerals produces a geothermal gradient where temperatures increase with depth, as in sedimentary basins.[55] Permeable structures, caused by faults or fractures, produce the surface manifestations of geothermal systems such as geysers, fumaroles, or hot springs.[62]

Geothermal resources may be classified as low, medium, or high enthalpy based on the geothermal resource temperature and thermodynamic properties. The United States Geological Survey (USGS) establishes the boundaries between low, medium and high enthalpy resources as <90 °C, between 90 and 150 °C and >150 °C, respectively.[35] Moreover, Figure 1 shows the alternative classifications proposed by other authors for which the criteria for each type of geothermal resource vary per the temperature.[35]

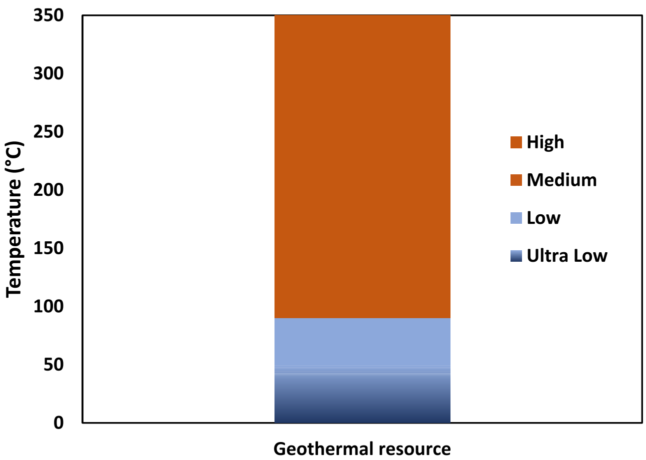

Figure 1. Classification of geothermal resources based on temperature. Color scale from blue (ultralow enthalpy geothermal resource) to red (high enthalpy geothermal resource). Adapted with permission from Williams.[35] Copyright 2011 Stanford Geothermal Program.

Despite the structural similarities between geothermal and oil/gas reservoirs, there are complications in the drilling of geothermal reservoirs. Geothermal reservoirs may comprise igneous or metamorphic rocks, which are more difficult to drill compared to sedimentary rocks found in oil and gas reservoirs. Moreover, the high temperatures associated with geothermal drilling require special consideration and design to maintain the wellbore's integrity and ensure the longevity of assets.[60]

Lindal's diagram is used to show potential applications of geothermal energy as a function of the temperature of the extracted geofluid.[64] Direct heating applications are applicable to the complete spectrum of temperatures encountered in association with geothermal resources. Low- or medium-enthalpy geothermal resources can be harnessed for power production using binary cycle technology such as the ORC. High enthalpy geothermal resources can take advantage of dry steam or flash generation technologies.

3. ORGANIC RANKINE CYCLE (ORC): CYCLE POWER PLANTS FOR GEOTHERMAL ELECTRICITY GENERATION

In the oil and gas industry, the ORC is the most extensively used technology for energy generation from geothermal resources.[30,65,66] It follows a process similar to the conventional Rankine cycle, although it uses an organic compound as a working fluid rather than water.[7,68] Figure 2 shows a basic

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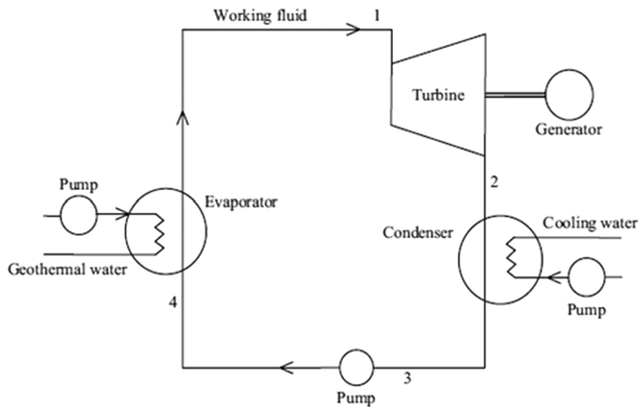

Figure 2. Schematic of basic organic Rankine cycle. Components: turbine, condenser, pump, evaporator, and working fluid. Reprinted with permission from ref 70. Copyright 2007 Elsevier.

diagram of the ORC, which starts with the geothermal water entering through the evaporator where the working fluid is boiled (Process 4-1). The resulting vapor after phase change is used to drive the turbine (Process 1-2). In this study, the generator converted kinetic energy to electricity.[69] Then, the working fluid leaves the turbine and changes phase from vapor to liquid in the condenser (Process 2-3). Finally, the liquid phase working fluid is pumped back to the evaporator (Process 3-4) to then begin the cycle.[69−71] This cycle demonstrates an average thermal efficiency between 9 and 12%.[36]

Babatunde et al.[72] highlighted certain performance advantages of ORC systems compared with the conventional Rankine cycle when the operational temperature was considered to be low. Using organic fluids makes it possible to use one expander or turbine, decreasing capital and operational expenditure because of the simple unit design. Moreover, the maximum operating pressure that an ORC system must tolerate is lower than that of the conventional Rankine cycle equipment, thus reducing costs. ORC systems are preferred for power generation with low to medium enthalpy thermal sources and design considerations must be made to accommodate the working fluid that was selected. Therefore, the ORC system's performance, costs, and safety partly depend on the selection of working fluids.[27,73]

There are multiple important considerations in the selection of an ORC working fluid. It must have optimal physical and thermodynamical properties for the given heat source[67] to maximize thermal efficiency and power output.[71] Organic compounds must not degrade or react within the ORC system as these could pose operational and industrial safety risks.[74] Working fluids should not threaten the environment or human health.[67,71,73] Low flammability, toxicity, and global warming potential (GWP) are desirable properties.[67,71,73] Refrigerant fluids, such as R123, R113, R114, R134a, Rc-318, and R245fa, are used as working fluids in ORCs.[72]

Velez et al.[74] and Pethurajan et al.[73] show relationships between multiple fluid properties, such as latent heat and molecular weight, and the operational and economic parameters of an ORC system. These properties affect parameters, such as power output, pump requirements, and the generation equipment's overall size. The freezing point of the working fluid must be higher than the minimum temperature expected in the system to avoid crystallization; furthermore, the boiling temperature of the working fluid should be lower than the input heat source to prevent the entrance of liquids inside the turbine. High-specific-heat and high-viscosity working fluids increase pump work and friction losses, reducing the system efficiency.[73] There are fluids with suitable properties for current ORC applications; fluids, such as R245fa, have shown promising results in their application.[67,74]

4. GEOTHERMAL ENERGY IN ABANDONED WELLS

One of the principal challenges of geothermal power projects is the cost of drilling and completion, which can account for 30%−40% of the total project cost.[76−78] Similarities in equipment, materials, and drilling practices between geothermal and oil/gas wells could benefit both industries.[76,79] The repurposing of abandoned oil and gas wells has been proposed as a possible source of renewable power that benefits from the preexisting knowledge of the reservoirs and fluids in the subsurface by oil and gas exploration.[77,80−82] This may eliminate the requirement for drilling new wells. It has been proposed that the retrofitting of oil and gas wells for geothermal projects could reduce the costs of well abandonment.[76,80] The presence of >2 million abandoned wells in the United States alone highlights the potential footprint for applying this technology.[76,81,83] Oil and gas companies could add productive geothermal assets to their portfolios or sell abandoned wells to geothermal developers.[76]

Certain studies examined the feasibility of extracting geothermal energy using abandoned oil and gas wells. Bu et al.[54] developed a mathematical model via numerical methods, which described heat exchange between fluid and rocks using a double-pipe heat exchanger and demonstrated the interdependence between geothermal gradient, resource flow rate, and power generation in abandoned wells. This study concluded that it would be possible to establish a power plant with a net power output of 54 kW given a geothermal gradient of 45 °Ckm^{-1} and a geothermal resource temperature of >120 °C, which was relatively constant with time.[54] A study by Cheng et al.[52] evaluated the effects of formation heat transfer and analyzed a geothermal power installation in abandoned wells in northern China using a double pipe as a heat exchanger and isobutane as the working fluid for the ORC. The results demonstrated that after 300 working days in one well with a temperature of ∼400 K for the transport fluid, maximum net power of 154 kW can be obtained with an overall efficiency of >13%.[52] Moreover, the abandoned horizontal oil and gas wells can be repurposed for power production, as shown by Harris et al.[28] Their study quantified the amount of electricity produced by developing a closed-loop system using directionally drilled wells and an ORC system. The Haynesville Shale formation, located in Northwest Louisiana and East Texas, was the subject of this work, which has been drilled and features high bottom-hole temperatures. Parameters such as flow rate, inlet temperature, geothermal gradient and thermal properties of the rock formation were examined. After a simulation, the electrical power generated starts at 500 kW and decreases to ∼300 kW after 50 years of operations. The study ran cases assuming ORC efficiencies (thermal to power efficiency) of 6 and 10%; after 20 years of operations, the generation output is 120 and 200 kW, respectively.[28] Hu et al.[84] presented a case study of a developed simulation model to determine the feasibility of retrofitting deep petroleum well in a coaxial bottom-hole heat exchanger in Canada's Western Canadian Sedimentary Basin. The study evaluated multiple operational conditions for 25 years of geothermal energy production. Per

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ACS Omega 2022, 7, 40603−40624

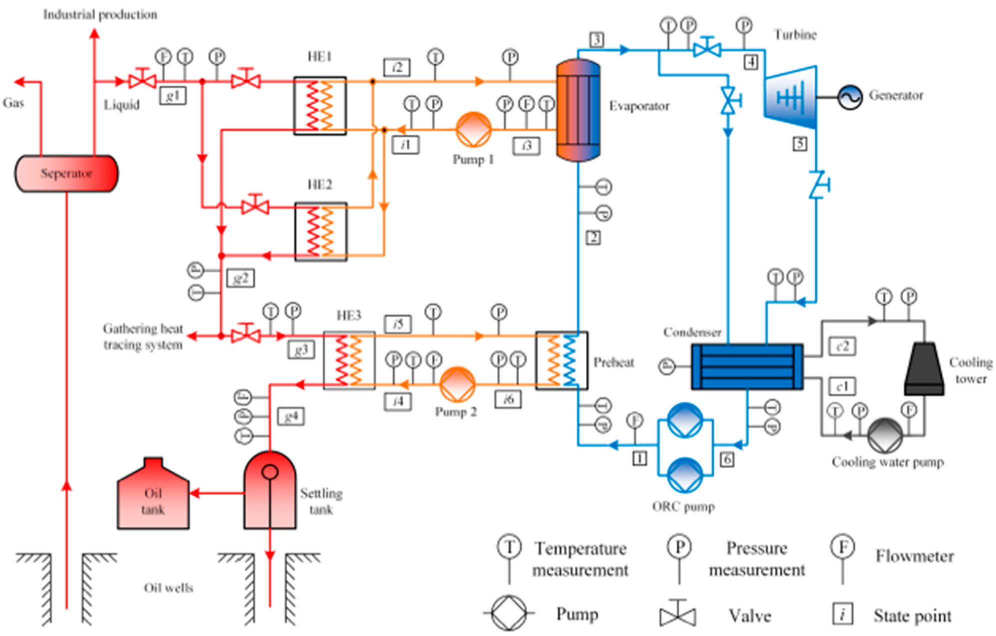

Figure 3. Schematic of ORC system in Huabei oilfield. Geothermal water (red), intermediate water (orange), R245fa (blue) cycles. Reprinted with permission from ref 86. Copyright 2017 Elsevier.

the simulation results, the energy production during the first five years of operation decreased from 0.8 to 0.4 MW because of a decrease in the temperature caused by a thermal equilibrium reached by the rocks in the subsurface. Moreover, the power generation shows a more controlled decline down to 0.38 MW in the 25th year simulation.[84] To analyze the heat transfer and fluid flow through the reservoir over 50 years of operation, Mehmood et al.[85] developed a mathematical model for thermal- and hydraulic-coupling processes to represent an abandoned gas well located in the Chiltan formation in Pakistan. This study uses a doublet well system comprising injection and production wells used for heat extraction. These wells were separated by a distance of 200 m, and the initial temperature in the reservoir was 194 °C.[85] The results demonstrated a heat production and power generation of 49.4 MWt and 12.6 MWe, respectively, during the first five-year simulation. After 40 years of heat recovery, heat production decreased to 43.8 MWt, and power generation decreased to 5.6 MWe because of decreased reservoir temperature.[85] Despite the decrease in power generation and heat production, the authors concluded that the project was economically feasible because these parameters were above the commercialization target of 25 MWt and 3.5 MWe for heat production and power generation, respectively.[85] A preliminary test of a 500 kW ORC system using oilfield-derived geothermal resources in abandoned wells in the Huabei oilfield in China was conducted by Yang et al.[86] Figure 3 shows the schematic of the ORC system, including the geothermal water (red cycle), intermediate exchange (orange cycle), ORC (in blue), which used R245fa as the working fluid, and the cooling water (black cycle) cycles.[86]

Per the authors, although the intermediate heat exchange cycle reduces the system's thermal efficiency, it was necessary to implement this measure to reduce equipment cleaning costs. The oil in the produced fluids can cause blockages that reduce the thermal efficiency of the evaporator and preheater. In addition to mitigating possible working fluid, losses during the intermediate cycle improve the power plant uptime because cleaning requires a complete shutdown of generation equipment. After ~16 h of operation, the results reveal a power output between 60 and 160 kW. The average efficiencies of intermediate heat exchange and ORC cycles (thermal to power generation) were 77.98 and 4.46%, respectively.[86]

Moreover, Wight et al.[87] proposed the use of abandoned oil wells to produce geothermal energy. Their modeling approach considered water circulation through the annulus of an abandoned well between insulated production tubing and casing. After water is heated in the wellbore bottom, it is lifted to the surface and passed via a binary cycle for electricity production. The energy produced using the binary cycle is between 108 and 630 kW using 2.5 and 15 kg s^{-1} mass flow rates, respectively.[8]

Alimonti et al.[88] developed a numerical model to evaluate the possible application of a "WellBore Heat eXchanger" (WBHX) in the Villafortuna Trecate Field, located in Trecate, Italy. This heat exchange technology prevents corrosion and scaling that may occur with other approaches by avoiding the direct application of geothermal fluids in the wellbore. The proposed WBHX is a coaxial heat exchanger, a closed-loop system in which the bottom of the well is sealed, and a heat carrier fluid is pumped via the annulus space between the well casing and an insulated production pipe. The fluid returns to the wellhead at the surface via the internal diameter of the insulated pipe.[88] Extracted heat can then be converted in electricity through an ORC installation, as shown in Figure 4.[88] R600a, R-C318, and R-3-1-10 were evaluated as working fluids for ORC optimization.

Simulations of this technology using water and diathermic oil as heat carrier fluids in the WBHX were conducted to examine the optimal configuration for the system. The study concludes that the optimal working fluid in the ORC unit is R-C318, and the best performing heat carrier fluid in the WBHX was water. The simulations estimate that net electrical power of up to 134 kW per well is possible using water as the heat carrier fluid at a flow rate of 15 m^3 h^{-1} per well, which represents a thermal extraction rate of 1.5 MW.[88] In this study, two scenarios were considered: a low case, where eight wells

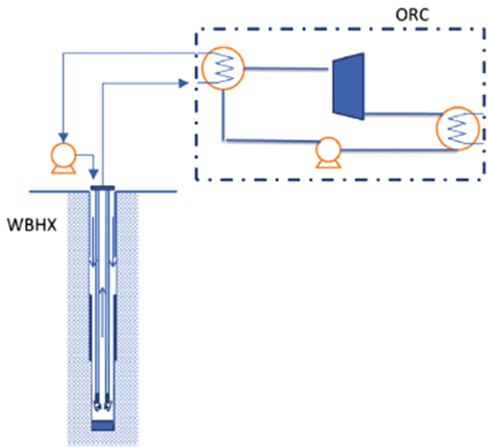

Figure 4. Schematic of WellBore Heat eXchanger (WBHX) and ORC for electricity generation. Reprinted with permission from ref 88. Copyright 2016 Elsevier.

were available for heat extraction, and a high case, where 40 wells were available for this operation. In the low case, the net electrical power generated for the worst case is ∼1 MW, whereas the high case could produce up to 5.2 MW of electrical power.[88] A complementary study[29] evaluated the power produced by the WBHX over time and compared the efficacy of ORC systems and Stirling motors in converting thermal energy in electrical power. In this study, the WBHX with a flow rate of 20 m^3h^{-1}, an inlet temperature of ∼100 °C, and an outlet temperature of 40 °C were capable of extracting 1.3 MWt of thermal energy after a year of operation. The ORC plant used R-C318 as a working fluid in the original study.[29,88] Air is the working fluid in the Stirling motor with maximum and minimum volumes of 150 and 50 L, respectively.[29] From the 1.3 MW thermal energy extracted from a single well using the WBHX, the ORC plant could generate 121 kW of net electrical power. However, the Stirling motor produced 152 kW, suggesting that a Stirling motor is more efficient for electrical power generation.[29] Considering the same high and low cases from the original WBHX study,[88] the ORC plant would have an electrical generation potential between 968 and 4.84 MW, and the Stirling motor would be capable of generating power between 1.21 and 6.08 MW.[29]

The use of abandoned wells in the oil industry for geothermal resources can be highlighted; simulations and models have allowed the use of this technology that saves investment in projects related to geothermal energy. By identifying the geothermal resource as a resource of medium and low enthalpy, the models presented show the development of ORC systems using working fluids such as Rc318. Moreover, the direct use of the geothermal resource is analyzed using an injection fluid, such as isobutane and a turbine on the surface, thus creating a closed cycle between the surface and reservoir. These investigations open a novel panorama in using the geothermal resources for both the oil and gas industry. Table 1 shows the most outstanding investigations related to the use of abandoned wells in the oil industry for geothermal resource use.

5. CO-PRODUCTION OF FLUIDS AND ELECTRICAL ENERGY (ACTIVATE WELLS) FROM THE WATER PRODUCED

5.1. Assessments of Co-produced Fluid Geothermal Power.

Per Raos et al.,[89] in a typical producing oil well, the water cut (the relative percentage of water in the produced fluids of the well) can increase from low values, close to zero, up to values exceeding 95% as time passes and the field "matures." When the temperature of produced water is high, the thermal heat can be either harnessed to produce electricity or for direct applications such as space heating. The implementation of heat recovery in oilfields is an opportunity to save money, reduce fuel consumption, extend the economic life of an oilfield, and reduce greenhouse gas emissions for external electricity consumption. Consequently, many studies examined the potential to co-produce hydrocarbons and geothermal energy considering the produced water.[31,53,65,90−105]

Li et al.[100] presented an approach in which an ORC plant was combined with a gathering heat tracing subsystem (GHT)—a system to maintain or increase the temperature of pipes or vessels—and an oil recovery subsystem. A numerical model was developed to simulate the performance of various working fluids in an ORC power generation system based on the previously published data. As a base case in this study, the R123 refrigerant was selected as the working fluid whose net power output was 270 kW, and a thermal efficiency of 3.96% was achieved. Other working fluids were employed in the model to evaluate possible efficiency gains. The maximum power output in the ORC system was obtained using R601a and R601 as working fluids, 380 and 376 kW, respectively. In an oil facility, boilers must maintain the oil viscosity at an optimal value; a GHT subsystem that uses co-produced water as a heating source is a viable substitute for the boiler, lowering fuel costs and mitigating greenhouse gas emissions.[101] Another research by the same lead author[100] proposed and modeled a cascade uses system based on a power generation system, Li−Br absorption refrigeration, oil gathering, and transportation heat tracing (OGTHT) direct heat applications. In this system, produced fluids are separated using a three-phase separator in gas, oil, and geothermal water. The water stream passes via two-stage series ORC subsystem (TSORC) using an R245fa working fluid, during which a temperature of 20 K decrease occurs as the geothermal water exchanges heat in the ORC system. Subsequently, the water enters the Li−Br absorption chiller unit. After its exit from the absorption chiller, the water enters the OGTHT subsystem to provide heat that facilitates the transportation of produced oil. Finally, before its reinjection in the reservoir, the remaining heat in the geothermal water is directly used for heating. In this approach, the TSORC achieved a maximum net power output of 580 kW with a thermal efficiency of 9.5% where the inlet temperatures of these two evaporators were 98 and 92 °C. Moreover, despite considering the revenues from oil production, a payback period of 3.07 years was calculated, thus yielding good technical and economic performance.[100]

Co-produced fluid-geothermal potential in the United States was estimated by Augustine et al.[103] using three models for electricity-generation potential: exergy, the Massachusetts Institute of Technology (MIT) model, and the commercially available "off-the-shelf" (COTS) model. The authors consolidated a database with well production data, including

Table 1. Summary of Research on the Use of Abandoned Wells in the Oil Industry to Provide Geothermal Resources

title	authors	year	temperature range for produced fluids	power output in a single well	physical model for wells	energy carrier fluid	country	modeled well feature
geothermal energy production utilizing abandoned oil and gas wells	Bu et al.[54]	2012	130−128 °C	53.7 kWe	double-pipe heat exchanger	water		abandoned well with a depth of 4 km and geothermal gradient of 25 and 45 °C/km inner radius of the extraction well is 0.0500 m; the radius of the injection well at the top is 0.1700−0.1500 m, and the length is 2.5 km; the bottom diameter is 0.1700−0.1500 m with a length of 1.5000 km
studies on geothermal power generation using abandoned oil wells	Cheng et al.[52]	2013	127 °C	239 kWe	double-pipe heat exchanger directly connected to ORC	isobutane	China	abandoned well with a depth of 6 km; the inner radius of the injection well is 0.1400 m; the internal radius of the injection well is 0.1250 m; the external radius of the recovery well is 0.1600 m; the internal radius of recovery well is 0.0500 m
geothermal energy from abandoned oil and gas wells using water in combination with a closed wellbore	Wight et al.[87]	2015	130 °C	109 kWe	double-pipe heat exchanger	water		the geothermal gradient is 31.1000 °C/km; abandoned well with a depth of 4.2000 km; the external radius of the hole is 0.3112 m; the casing radius is 0.2445 m
study of geothermal power generation from a very deep oil well with a wellbore heat exchanger	Alimonti and Soldo[88]	2016	120 °C	134 kWe	WellBore Heat eXchanger	water	Italy	the geothermal gradient is 25 °C/km; the well has a depth of 6.1000 km; the external radius of the injection well is 0.1390 m; the internal radius of the injection well is 0.121 m; the external radius of the recovery well is 0.0900 m; the internal radius of recovery well is 0.0780 m
potential for heat production by retrofitting abandoned gas wells into geothermal wells	Mehmood et al.[85]	2019	193−167 °C	12000−3000 kW	injector well/producer well	water	Pakistan	the geothermal gradient is 43 °C/km; well with a depth of 4.5000 km; the wellbore radius is 0.2160 m
numerical modeling of a coaxial borehole heat exchanger to exploit geothermal energy from abandoned petroleum wells in Hinton, Alberta	Hu et al.[84]	2020	40−29 °C	380 kWe	borehole heat exchanger	water	Canada	the geothermal gradient is 38.1000 °C/km; the well has a depth of 3.5000 km; the external radius of the injection well is 0.0889 m; the external radius of the recovery well is 0.0380; both tubes have a wall a thickness of 0.0100 m
a numerical investigation into the use of directionally drilled wells for the extraction of geothermal energy from abandoned oil and gas wells	Harris et al.[28]	2021	90−100 °C	400−120 kWe	injector well/producer well	water	United States	the geothermal gradient is °C/km; the well has a depth of 4 km

https://doi.org/10.1021/acsomega.2c04374
ACS Omega 2022, 7, 40603−40624

production volume, flow rate, and bottom-hole temperatures. Temperature maps were used as a complementary source of information. They conclude that 4.2 billion bbl of co-produced water suitable for power production is extracted every year. Consequently, an estimated 1300 MWe co-produced fluid-power potential is available based on the exergy model, 560 MWe based on the MIT model, and 276 MWe based on the COTS model. The authors note that the exergy model corresponds to the theoretical upper limit for electrical generation, whereas the COTS model is the most realistic approach.[103] Auld et al.[104] assessed the potential power generation from co-produced brines in fields located in the North Sea to determine whether it would be possible to meet the power requirements of an offshore oil platform with an ORC generation unit fed using co-produced water. Power generation from the ORC was simulated using an analytical model that used co-produced brines from oil and gas fields in Brent Province. The lowest potential identified was 0.45 MW, and the largest potential identified was 31 MW. Simulations demonstrated that 6 of these 21 evaluated fields had an electrical generation potential of >10 MW. This study concludes that electricity generated from co-produced water could contribute to the electrical supply on offshore platforms where power requirements vary between tens of MW and several hundred MW.[104]

Banks et al.[105] examined the gross geothermal power potential of the Virginia Oil Field. Their investigation used three different methods to assess gross power production potential during 25 years of operation. Using a reservoir volume method, an average power potential of ∼172 MWt and 28 MWe was calculated through a different deterministic method based on information from 190 wells, including bottom-hole temperatures historical water production. An average power potential of 115 MWt and 16 MWe was estimated. Finally, a total power potential of 199 MWt and 32 MWe was estimated using a Monte Carlo approach for heat power. Differences in these estimations can be attributed to the different assumptions inherent in each model and the different data inputs required for each model.[105]

Akhmadullin et al.[102] analyzed the potential of co-produced fluid geothermal power generation in the petroleum industry using a numerical model that represented an ORC power generation system using R134a as a working fluid. The mathematical model developed in MATLAB was validated using preexisting data from the geothermal power installation in Chena, Alaska. Simulations were conducted using temperatures ranging between 135 and 91 °C. Turbine inlet pressures were manipulated to maintain the working fluid in the vapor phase. The results of this study demonstrated that at temperatures of 135 °C, a maximum of 1.6 MW of electric power could be generated using a flow rate of 80,000 barrels of water per day (BWPD), and 200 kW could be produced using a flow rate of 10,000 BWPD.[102] A carbon dioxide emission analysis demonstrated that in the 200 kW power case, up to 397,347 kg of carbon dioxide emissions per year could be avoided compared to alternative power sources such as the combustion of nonrenewable resources.

Many studies on co-produced fluid geothermal power have focused on the Williston Basin, located between the U.S. states of North Dakota and Montana and the Canadian province of Saskatchewan.[53,92] This basin has 20 formations producing oil and water where temperatures in the subsurface vary between 65 and 150 °C. Two of the most heavily exploited formations for oil and gas are the Three Forks and Bakken formation, a prolific unconventional reservoir. With estimated resources exceeding 400 billion barrels OOIP, significant infrastructure and power supply must support this development.[92] Two different studies were proposed to demonstrate the viability of co-produced fluid geothermal energy at the Williston Basin.[53]

The first project examined the Eland-Lodgepole Field located in North Dakota. Between 2008 and 2015, this field produced 12,600 barrels of fluid per day from 12 wells, including 11,350 barrels per day of water. The water in this field was collected in a central facility at temperatures of over 100 °C which made it possible to implement the co-production project. Assuming thermal-to-power efficiencies of 8 to 12%, a power generation potential ranging between 350 and 568 kW was projected. Despite this power potential, this project never progressed beyond the feasibility study due to its sale by the original field operator.[5] The second project involved the University of North Dakota and focused on a Continental Resources field in North Dakota that was undergoing a secondary recovery caused by flooding. The geothermal resource in this study was the 30,000 barrels of water per day being produced from two water supply wells.[53] The two ORC units selected for power generation in this project used R245fa refrigerant as the working fluid[112] and could produce 125 kWe with efficiencies close to 14% with a resource temperature of 98 °C at the system's inlet.[93] The study notes that, once implemented in the field, only one of the proposed units was operational providing an average production of 124 kW/day of electricity.[90,93] Despite having produced power at the expected rates, unanticipated problems with the refrigeration system led to a shutdown of the ORC unit after only 2 days of operation.[31] During this operation, a winter storm froze the water present in the system and caused extensive damage to the generation unit. The estimated repair costs exceeded the available funding, and the decision was made to abandon the project.[90,93]

A separate study on the Williston Basin investigated the viability of co-produced fluid geothermal power in the Banks Field. In 2018, the overall production among the 260 active wells in the Banks Field amounted to 1.9 million barrels of oil and 2.4 million barrels of water.[91] This study proposed using small, 20−23 kWe ORC power generation units. The wells in this field are pumped at low rates to maintain a favorable oil to water production ratio which is why the individual ORC units proposed have such a limited generating capacity. According to the authors, the power generated from the ORC units could be used on-site to supply electricity to the electro-submersible pumps or for other field activities.[91] Based on the petrophysical properties and fluid temperatures, the Williston Basin has an estimated 4.0×10^{19} J of thermal energy that could be used to generate 1.36×10^{9} MWh of electricity.[90,93] Gosnold et al.[53] estimated that by 2032, oil and gas production from the Bakken and Three Forks Formations will require 2600 MW of electrical power. If an ORC network capable of producing 2900 MW of geothermal energy is developed in this basin, its power demand could be fully satisfied through geothermal energy, and 10 million metric tons of CO_2 emissions could be avoided during the entire producing life of the project.

The study of the Wytch Farm oilfield in the U.K. is another assessment of co-produced fluid geothermal power generation using an analytical model based on thermodynamic heat-balance along with mass balance and the use of RefProp (version 9.1).[95] Located in Dorset, England, the study focuses on two sites, designated as the M site and the F site. Site M can treat between 160,000 and 180,000 BWPD, which exits the separator system at temperatures ranging between 65 and 67 °C. Site F treats between 90,000 and 130,000 BWPD with a temperature of 66 °C at the separator outlet. In this study, the co-produced water was supposed to pass through an ORC unit after being separated from the hydrocarbons produced. A power generation efficiency must be assumed in this model to determine electrical generation potential. Using data from other operational ORC power plants, and applying linear regression analysis, the authors developed a function relating the thermal efficiency of the power plant as a function of the inlet temperature of the geothermal resource.[95] Using a calculated efficiency of 5.2%, derived from correlations and employing the parameters in Table 2, the useful thermal heat available ranged between 1100 and 1450 MW for site M and 700−1120 MW for site F.[95]

Table 2. Design Parameters for the Wytch Farm Oilfield Case Study (Adapted with Permission from Ref 95. Copyright 2017 Stanford Geothermal Workshop)

site M		site F	
T_{in} (°C)	67	T_{in} (°C)	66
η (%)	5.2	η (%)	5.2
mass flow rate (kg s^{-1})	290−330	mass flow rate (kg s^{-1})	170−220
t_{out} (°C)	50−55	t_{out} (°C)	41−46
Q (kW)	1100−1450	Q (kW)	700−1120

Isobutane, butane, propane, ammonia, R134a, and R152a were used as the simulated working fluids in the model. The most suitable fluids for the modeled ORC unit were determined to be isobutane and butane due to their moderate mass flow rate and low turbine inlet pressure. Using isobutane as the working fluid, the generation potential was estimated at 1.4 MW for site M and 0.85 MW for site F. The economic analysis considered a production period extending from 2018 to 2040, when the production license for the Wytch farm field expires. Assuming a resource temperature of 65 °C, the cumulative power generated during this period, for both fields, would be approximately 301 GW. Assuming a discount rate of 10%, throughout the production period, then the Net Present Value (NPV) of this project is estimated to be between £0.72 and £6.10 million for site M and between £0.47 and £3.88 million for site F, highlighting the economic feasibility of co-produced fluid geothermal power generation at this location.[95]

The Villafortuna-Trecate oilfield, located in Italy, was a separate study on co-produced fluid geothermal power generation. Having started production in 1989, current production of the field has experienced declines and high-water cuts.[133,134] Alimonti et al.[106] built a one-dimensional reservoir model to simulate single-well production. Based on parameters derived from the subject field, this model assumed that the well was placed in the middle of a circular reservoir with aquifer pressure support, where oil and water are the only fluids in the reservoir. Ten years of production were simulated, after which the cumulative amount of oil production was approximately 3.2 million barrels, and the water cut was close to 100%. The temperature of the co-produced fluids varied between 100 and 130 °C so that an ORC unit with a power output of 500 kW was proposed. During this same simulated 10 year production period, 25 GWh of power was generated using the 500 kW ORC. This study also evaluated a scenario where geothermal energy was exploited in a direct-use application. According to that evaluation, more than 230 houses could be heated from a thermal heat source of 2.5 MWt. The most favorable arrangement considered was a combined power and heating scheme, where each well could provide 143 kWe of electrical power and 660 kWt of heat for direct use.[106]

Bennett[94] investigated the feasibility of co-produced fluid geothermal power across nine oilfield operations in the Los Angeles Basin. Initially, each oilfield was modeled with STARS software to define the changes in various reservoir parameters that would change over the project's lifetime, including water cut, fluid rates, and the temperature of the produced fluids. An estimated electrical output in the assets of interest was then generated with the modeled reservoir data and assumptions derived from low enthalpy geothermal projects currently in operation, similar to the method proposed by Singh et al.[95] Once the power generation figures were estimated, an economic feasibility assessment investigated the financial dimension.

The model constructed in STARS consisted of an injector-producer well pair representing one-quarter of an inverse five-spot pattern. The model assumed a homogeneous reservoir, no aquifer support, and two-phase fluid flow (water and dead oil).[94] Owing to the lack of information available for the fields of interest, some of the model input values were assumed or derived from other, similar models. Table 3 highlights which properties were specific to each oilfield and the assumed values.

Table 3. Oilfield Properties for Simulation in Previous Research[94] (Adapted with Permission from Ref 94. Copyright 2012 Stanford University)

porosity	specific for each oilfield
water saturation	specific for each oilfield
reservoir pressure	specific for each oilfield
reservoir temperature	specific for each oilfield
initial water saturation	specific for each oilfield
depth	specific for each oilfield
fluid rate	specific for each oilfield
geothermal gradient	specific for each oilfield
permeability	300 mD
oil molecular weight	300 lb mol^{-1}
liquid compressibility	5×10^{-6} (psi^{-1})
coefficient of thermal expansion	3.8×10^{-4}
coefficient of liquid heat capacity	300
oil partial molar density	0.1 lb $lbmol^{-1} \cdot ft^{-3}$

Several threshold criteria were established to assist in selecting the most suitable fields for co-produced fluid geothermal power generation. The author asserts that the minimum geothermal fluid temperature, the minimum generation unit size, and the reinjection temperature must be 70 °C, 20 kW, and 40 °C, respectively.[94] These threshold values helped to identify nine suitable oilfields for power generation from 49 active oilfields in the Los Angeles Basin. The Sawtelle, Beverly Hills, Seal Beach, Rosecrans, Inglewood, Santa Fe Springs, Huntington Beach, Wilmington, and Long Beach fields are among these. Following the STARS simulations, and the estimations of power generation from each oilfield, four oilfields (The Sawtelle, Seal Beach,

https://doi.org/10.1021/acsomega.2c04374
ACS Omega 2022, 7, 40603−40624

Table 4. Summary of Power Plant Parameters for Oilfields Able to Generate Power (Adapted with Permission from Ref 94. Copyright 2012 Stanford University)

	Wilmington Oilfield	Beverly Hills Oilfield	Inglewood Oilfield	Long Beach Oilfield	Santa Fe Springs Oilfield
total production (bbl day^{-1})	97,435	26,833	19,727	124,683	53,816
water cut (%)	96	92	98	97	98
production temperature (°C)	70	78	70	70	70
reinjection temperature (°C)	40	40	40	40	40
power plant efficiency (%)	4.46	5.16	4.45	4.42	4.45
power plant size (kW)	1,015	406	205	1273	558
NPV	\$895,818	−\$270,916	\$1,747,426	\$8,262,660	\$3,143,029

Rosecrans, and Huntington Beach fields) were considered incapable of electrical power generation due to heat losses in the wellbore that caused the temperature of the produced fluid to fall below the temperature threshold of 70 °C. The wellbore heat losses in these excluded fields were associated with low flow rates.[118] An economic analysis was carried out on the remaining fields to determine the NPV of co-produced fluid geothermal power generation. During this analysis, The Beverly Hills field project was NPV negative.[94] A power generation potential of 3000 kW was identified for the remaining prospective oilfields, amounting to a total NPV of \$14 million.[94] Table 4 summarizes the power plant parameters of several oilfields in this study.

Studies evaluating the geothermal resources in oilfields have made it possible to elucidate the potential for the use of these resources, as well as the techniques needed to optimize their use. Among the research reviewed, we highlight the analysis of different working fluids, ORC efficiencies, production fluid temperatures, and the use of waste heat using different techniques and simulation software. A summary of the research having the greatest impact regarding the study of the viability of the use of geothermal resources in oilfields can be seen in Table 5.

5.2. Field Applications of Co-produced Fluid Geothermal Power. One of the first co-produced fluid geothermal energy applications in the field was implemented in Pleasant Bayou[108] on the Texas Gulf Coast.[109,110] Pleasant Bayou was identified as a geo-pressured resource. Under a U.S. Department of Energy (DOE) program a pilot production well was drilled.[111] The fluids produced consisted of brine and gases in solution. The gas composition included methane (≈85%), heavier hydrocarbons (≈5%), and carbon dioxide (≈10%).[110,112] To take advantage of the heat of this resource, a hybrid power plant composed of a gas engine and a binary cycle power generation unit was proposed. The main advantage of this configuration was that the waste heat from the gas engine could be used to increase the temperature of the fluids produced in the binary cycle. This temperature boost improved the overall efficiency of the binary cycle generation unit. Brine production rates in the test-well were estimated at 20,000 bbl day^{-1} with 22 SCF bbl^{-1} of gas solution and temperatures of ≈137 °C. After its exit from the power generation unit, the brine was reinjected into the reservoir and any unused gas in the engine was sold. The gas engine was designed to produce 650 kW of electrical power. The binary cycle generation unit, harnessing isobutane as a working fluid, was sized to produce 541 kW of electrical power. The parasitic loads in the system were estimated to be 209 kW, resulting in an overall anticipated net power generation of 982 kW. Power generation, after 5 months of operation, was 680 and 520 kW for the gas engine and binary cycle unit, respectively. Factoring in a parasitic load of 280 kW, the net power obtained in the field was 920 kW.[111,112] The increase in parasitic load can be attributed to higher-than-expected power requirements for pumping the produced fluids. It was noted that if the gas engine were turned off, the brine flow had to be increased from 63 to 72 m^3 h^{-1} to compensate for the heat that would have been obtained from the gas engine exhaust. In this way, the binary cycle alone could produce the same 520 kWe of gross power, and 305 kW of net power.[112] Importantly, this demonstration sold 3,445 MWh of power to the local utility during the pilot test while plant availability and capacity factors were 97.5 and 80.2%, respectively. From a technical point of view, the Pleasant Bayou pilot was successful.[111]

An experiment was conducted in the Huabei Oilfield, located in the LB Reservoir in China.[99] Water produced from several wells in this reservoir reached temperatures between 100 and 120 °C. The average formation temperature measured was in the range of 120 °C, and the geothermal gradient was found to be approximately 0.035 °C m^{-1}. The LB Reservoir began production in June 1978, and by 2012, the production wells had water cuts of approximately 98%. A geothermal power plant was installed in April 2011 to harness electrical power from the heat in the fluids produced. The generation unit installed was a 400 kW unit with a screw expander turbine which generated 310,000 kWh of power during 2880 h of operation.[99] The specifications for this ORC are listed below in Table 6.

The geothermal power plant operated with the fluids produced from eight wells in the LB Reservoir. The authors estimate that, over a period of 6 months, 2000 tons of fuel were saved, 6000 tons of carbon dioxide emissions were avoided, and the project resulted in an additional 19,214 barrels of oil being recovered by using the additional heat in the recovery processes. Xin et al.[99] estimate that 2,700,000 kWh per year will be generated from this field when the geothermal plant is fully operational.

The Naval Petroleum Field No. 3 (NPR-3) is a producing oilfield owned by the U.S. Department of Energy near Casper, Wyoming. Full development of NPR-3 was achieved in 1976. The potential for geothermal energy co-production in this field was identified based on the disposal of 40,000 bbl day^{-1} of water at temperatures of ≈88 °C.[65,96] Original estimates asserted that 300 kWe of electrical power generation was possible from this heat source. Consequently, the U.S. Department of Energy and Ormat Nevada, Inc. cooperated on a research project to produce geothermal energy from NPR-3.[65] This project was divided into two phases. The first phase took place from September 2008 until February 2009; technical problems plagued this phase. The unit had significant downtime due to issues with field production and problems with the turbine and generator systems.[98] Ormat designed and

Table 5. Investigations in the Study of the Viability of Geothermal Resources in Oilfields

title	authors	year	analysis type	geothermal resource temperature	power and thermal output/efficiency	energy utilization system	energy carried fluid	working fluid	fluid for cooling system	country
cascade utilization of low-temperature geothermal water in oilfield combined power generation, gathering heat tracing, and oil recovery	Li et al.[107]	2012	single well	110.9 °C	270 kWe/3.96%	ORC + gathering heat tracing subsystem (GHT) + oil recovery system	water	R123 R601a R601 R141b R245f R600	water	
power generation potential from co-produced fluids in the Los Angeles basin	Bennett et al.[94]	2012	set of reservoirs	100–63 °C	3550–530 kW	power plant	water			United States
potential for harnessing the heat from a mature, high-pressure-high-temperature oilfield in Italy	Alimonti et al.[106]	2014	single well	110–120 °C	660 kWt, 146 kWe, 500 kWe	heating, ORC, co-generation of heat and power	water			Italy
estimate of the near-term electricity-generation potential of co-produced water from active oil and gaswells	Augustine et al.[103]	2014	set of reservoirs	80–200 °C	1300000 kWe, 560000 kWe, 276000 kWe		water			United States
utilization of co-produced water from oil production: energy generation case	Akhmadullin[102]	2017	single well	135 °C	1000 kW	ORC	water	R134a		
geothermal power potential of the Virginia Hills Oilfield, part of the Swan Hills Carbonate Complex; Alberta, Canada,	Banks et al.[105]	2020	set of reservoirs	102 °C	172000–115000 kWt 28000–16000 kWe	oower and thermal plant	water			Canada
techno-economic performance of multigeneration energy system driven by an associated mixture of oil and geothermal water for oilfield in high water cut	Li et al.[100]	2021	single well	85 °C	550 kWe/9.5%	ORC + Li–Br adsorption refrigeration, oil gathering and transportation heat tracing, heat	water	R245fa ammonia/water	water	China

https://doi.org/10.1021/acsomega.2c04374
ACS Omega 2022, 7, 40603–40624

Table 6. Design Parameters for ORC Geothermal Power Plant in Huabei Oilfield (Adapted with Permission from Ref 99. Copyright 2012 Geothermal Resources Council Transactions)

flow rate (m^3 day^{-1})	2880
inlet produced water temperature (°C)	110
outlet produced water temperature (°C)	85−90
inlet cooling water temperature (°C)	21.1
outlet cooling water temperature (°C)	35.8
working fluid	R123
nominal power (kW)	400
output power (kW)	360
net power (kW)	310

implemented a 250 kW air-cooled power unit during the first phase. It was impossible to use water cooling due to the cold temperatures and high winds that could cause freezing in water-cooled systems.[97] The system was designed to handle 40,000 bbl day^{-1} of produced water at temperatures of ≈77 °C with isopentane as the working fluid.[65] By the end of this phase, 586 MWh of electricity was produced from 3.05 million barrels of produced water, with an average net power output of 171 kW.[98] In the second phase, which spanned the months between September 2009 and November 2010, an average net power production of 185 kW was achieved, resulting in 1332 MWh of power generated from 7.9 million barrels of water.[98] The operational parameters for both phases are highlighted in Table 7.

Table 7. Operation Parameters for the NPR-3 Field (Adapted with Permission from Ref 98. Copyright 2011 Stanford Geothermal Program)

	design	phase 1	phase 2
flow rate (bbl day^{-1})	40,000	12,000−40,000	11,000−50,000
produced water (bbl)		3,047,192	7,860,737
inlet water temperature (°C)	77	195−198	196−198
outlet water temperature (°C)	67	80−170	47−150
average ambient temperature (°C)	10	−7−85	−2−81
generator gross power (kW)	180	105−305	105−300
average net power output (kW)		171	185
total power produced (MWh)		586	1,332

Following 3.5 years of full operation from the beginning of the first phase, the total cumulative power produced reached 2120 MWh, obtained from 11,400,000 barrels of produced water.[97] The study concludes that enough electricity was produced to power 120 homes.[121]

A small-scale demonstration of co-produced fluid geothermal energy was made in a Mississippi Oilfield by Electratherm using its "Green Machine" ORC technology.[30] The field operator, Denbury Resources Inc., was using electric submersible pumps (ESPs) to develop the wells in this field, producing 100 bbl day^{-1} of oil and 4000 bbl day^{-1} of water. The temperatures of the fluids averaged ≈96 °C. During this pilot project, the water in the fluids produced was separated from the oil, after which the hot water was fed into a small, fully automated ORC unit with a nameplate power output between 30 and 65 kWe. The efficiency of this unit varied between 6% and 10% using R245fa as a working fluid. After more than 1000 h of operations, the power production was observed to vary between 19 and 22 kWe. The lower values in this range were attributed to the low temperatures of the water.[30] According to the manufacturers, this power output supplies about 20% of the required energy to run the ESP.[30]

The first power generation pilot using fluids produced from an oilfield in Colombia[113] was performed in 2021 in the Eastern Llanos sedimentary basin using a modular ORC technology to take advantage of produced oilfield water to produce power. The temperatures of the produced water were less than 100 °C and the net power produced was 70 kWe. This pilot represented an important step in emissions-free power technology because approximately 550 tonnes of carbon dioxide emissions per year were avoided. The pilot has several environmental and technical advantages, among which the recovery of streams considered byproducts in the oil industry and the decarbonization of operations carried out in oilfields stand out. One of the characteristics of this research is the evaluation of the geothermal resource in the oilfield based on the exergy and energy of the produced water in the field, where a distinction is made between the total amount of energy in the resource and the amount of usable energy from the same. Figure 5 shows the configuration of the geothermal system for use in oilfield in power production.

For the same basin, Laverde[114] developed a numerical modeling of a gas condensate field in the foothills region, where he found that it is possible to produce the water at more than 90 °C without any thermal breakthrough according to the simulation of 30 years. Also, the author indicates that more than 30 MWh of heat production can be obtained.

A variety of applications of geothermal resource use in oilfields have been applied at small scales using ORC systems. These systems allow the production of a significant amount of electricity that can be used to supply the needs within the oilfield. In addition, the investigations show that the ORC system may be complemented by the use of auxiliary fluids for heating to optimize the use of the geothermal resource. Table 8 summarizes the projects with the most significant impact on the use of geothermal energy in oilfields.

6. GEOTHERMAL ENERGY COMBINED WITH ENHANCED OIL RECOVERY OPERATIONS

Thermal enhanced oil recovery methods such as steamflooding, hot water injection, and in situ combustion, among others, are used to improve the mobility of heavy oil by the application of heat,[16,115,116] which reduces the high viscosity of the oil.[116] To increase the temperature of the injected fluids, heating facilities are required. Some studies have shown a possible synergy between geothermal energy and thermally enhanced oil recovery operations.[55,117,118]

One proposal, described by Cinar,[55] considered the development of an Enhanced Geothermal System (EGS) by implementing in situ combustion (ISC). It is a thermally enhanced oil recovery method commonly used with heavy or extra-heavy oils whereby an oxidizing agent is injected into the reservoir.[119] The reaction between the oxidizing agent and the oil leads to a temperature increase if the conditions in the reservoir are conducive to self-ignition. Otherwise, it is necessary to supplement this process with gas burners or electrical discharges.[120] The temperature increase from the combustion reaction is responsible for reducing oil viscos-

https://doi.org/10.1021/acsomega.2c04374
ACS Omega 2022, 7, 40603−40624

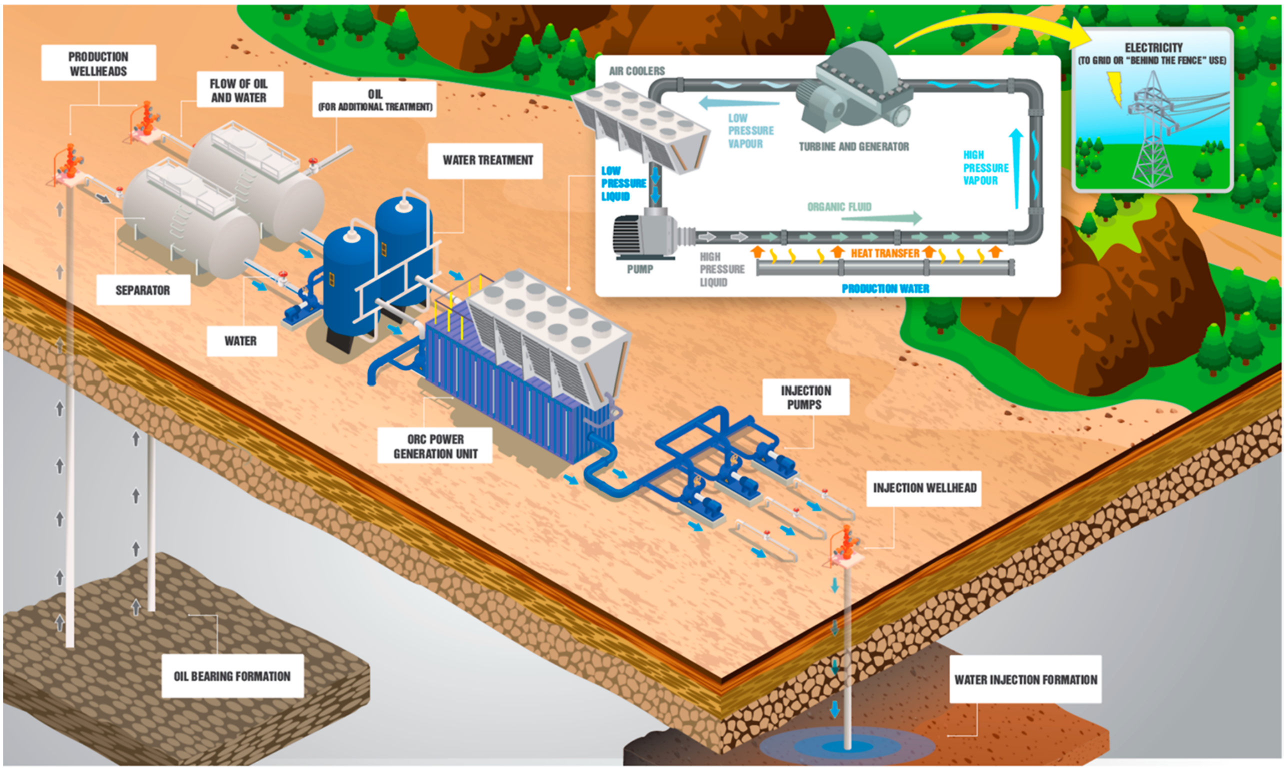

Figure 5. Configuration of the geothermal system for use in oilfield in power production. Reprinted from ref 113. Copyright 2022 MDPI.

ity.[121,122] The Cinar study considers one simulated scenario in the EGS in tandem with an ISC and showed that up to 8 MW of power and approximately 27 million kWh of total energy could be produced. This suggests a great potential, but to obtain these values, it is necessary to inject air at high rates for eight years, which impairs economic feasibility unless there is significant oil production.[55] Tian et al.[56] have also proposed a model where an EGS is created through the application of an ISC using a five-spot pattern. The model domain was composed of only a quarter of the five-spot pattern, which included one injector well and one producer well for the ISC model. In contrast, the geothermal model was simulated using a two-dimensional axisymmetric cylindrical model. The simulations covered a period of 50 years. Three scenarios were evaluated: heat recovery without the ISC, heat recovery using the ISC, and a case where the well is retrofitted to elevate the hole temperature at the bottom. The approach called Advanced ISC, circumvents the low-temperature stage of the ISC process and allows for faster recovery of upfront costs. Simulation results showed a cumulative production of electric energy of 30×10^6 kWh for the first scenario, 50×10^6 kWh for the second scenario, and 51×10^6 kWh for the third scenario. Despite there being a small difference between the second and third scenarios, in terms of cumulative electric energy produced, advanced ISC eliminates approximately ten years of low-temperature in the system, and allows outlet temperature to decrease slowly.

Teodoriu et al.[116] proposed a novel approach to heavy oil recovery where hot water injection and electrical production coincide. In this study, the water used for injection takes advantage of both the high intrinsic temperature of geo-formation waters after aquifer breakthrough and solar heaters that help raise the temperature of the injected fluids. Simulations were run reproducing an interval of 2200 days, wherein hot water was injected through an injection well, and fluids were produced from a vertical producing well. Then, a horizontal well was drilled. The simulation continued for a simulated period of 1150 days when the reservoir turned into a heat storage facility because of no oil production. In their study, the geothermal resources were quantified using the volume method and a daily heat value of 4.7 MWh was obtained.[116] To convert heat production to power, an efficiency level of 12% was assumed, which would correspond to the electrical generation of approximately 600 kWh per day.[116]

Limpasurat et al.[117] studied the possibility of geothermal power production in steam flooding projects, where any heat left behind in the reservoir after a steam breakthrough, or at the end of the field's life, could be recovered by water circulation. The model in this study consisted of one-quarter of an inverted five-spot well pattern with a footprint of five acres. Reservoir properties were taken from a comparable SPE study with an oil viscosity of 453 cP and gravity of 14° API. The simulation, lasting for 2400 days, was run using steam injection (at which time the water cut reaches 75%) followed by a period of 3800 days of waterflooding until the economic cutoff level for the field was reached. The cutoff was defined as the moment when the thermal energy output of the reservoir fell below the power required for water injection (7 MMBTU day^{-1}).[116] By the end of the simulation, the cumulative energy recovered was 3.02×10^4 MMBTU which, according to the study, could be 100 times greater if it was upscaled to the real-world field scale.[117]

A study by Zafar et al.[123] developed a numerical simulation model in a commercial thermal and compositional simulator to investigate the feasibility of a two-step approach to geothermal power production in an oilfield using steam injection. In the first step, a steam flood is designed to maximize oil recovery.

https://doi.org/10.1021/acsomega.2c04374
ACS Omega 2022, 7, 40603−40624

Table 8. Summary of the Most Important Characteristics of Research in the Study of the Application of Geothermal Resources in Active Oilfields

title	authors	year	geothermal resource temperature	production water flow	power and thermal output	energy utilization system	energy carried fluid	working fluid	fluid for cooling system	country
electrical power from an oil production waste stream	Johnson et al.[65]	2009	77 °C	40,000 bpd	250 kWe	ORC	water	isopentane	air	United States
geothermal power generator using co-produced fluids from Huabei oilfield	Xin et al.[99]	2012	110 °C	6151 bpd	400 kWe	binary screw expander system	oil/water	R123	water	China
Mississippi oilfield generates low-temperature, emission-free geothermal energy at the wellhead	ElectraTherm[30]	2012	96 °C	4000 bpd	200 kWe	ORC	water		water/air	United States
construction and preliminary test of a geothermal ORC system using geothermal resources from abandoned oil wells in the Huabei oilfield of China	Yang et al.[66]	2017	110 °C	30,191 bpd	656 kW	ORC	water	R245fa	water	China
oilfield application of co-produced fluid geothermal power in Colombia's Llanos Orientales Basin	Céspedes et al.[113]	2021	80 °C		70 kWe	ORC	water		air	Colombia

During the second phase, water is circulated in the reservoir to recover the residual subsurface heat remaining after the steam injection step. The model was based on the Chanda oilfield in Pakistan, a deep, high-pressure, high-temperature oilfield with a thick reservoir.[123] In the simulation, the steam-flooding period lasted for ten years until the threshold for economic oil production was reached. The subsequent water injection phase was simulated for 20 years. By the end of the simulation, the oil recovery factor was about 70%, and the cumulative electric power was around 310 MWh. The authors argued that the results in a real-world application would probably be higher, as this study only simulated a single injector-producer well pair and represented only a small part of the entire field.[123]

In a separate study involving enhanced oil recovery technologies, Purkayastha et al.[118] developed a Kelly Criterion scheme to optimize a microgrid capable of sustaining a SAGD (steam assisted gravity drainage) facility. According to their proposal, electrical power would be generated by exploiting the residual heat in the subsurface following a SAGD operation. SAGD is a process that involves the drilling of two horizontal wells that form a producer-injector pair, where the steam injection borehole is located a few meters above the production borehole. Injected steam from the higher borehole diffuses vertically through the reservoir, reducing the viscosity of the oil contained therein, which is then recovered by the lower well.[124,125] Three gas turbines and an ORC unit were used for power generation, which exploited 15 PJ of residual in the reservoir after the enhanced oil recovery (EOR) process.[118] The study estimated that an ORC working with isopentane could generate an average of 14.6 MW of power under these conditions. It should be noted that SAGD facilities, on average, require 15 MW of electrical power, suggesting the possibility that a SAGD project, through the use of an ORC system, could operate independently, without a connection to the electrical grid or fossil-fuel derived supplemental power.

Another study, by Liu et al.,[126] focused on waste-heat recovery in SAGD applications and considered using the waste heat from SAGD for electrical generation and industrial heating at the Liaohe oilfield in China. In this case, the hot water entered the ORC system at 170 °C and exited at a temperature of 90 °C; this outlet water was harnessed for direct use applications. In the ORC generation unit, R134a was selected as the working fluid. Under the conditions outlined in this study, a hypothetical project, containing 40 well groups with a total liquid production of 1,049,382 bbl day^{-1}, could achieve power generation amounting to 43,679 kW daily under the proposed scheme.[126] The remaining heat energy in the produced water could, after passing through the ORC system, heat a total building area of 90,000 m^2. This program would prevent the burning of 8000 tons day^{-1} of coal, replacing eight sets of steam boilers and 1500 small coal stoves, as well as the labor of 90 people, providing a clear environmental benefit. From an economic point of view, the electricity generated using this approach could reduce costs by as much as 22,000 yuan per day (≈$3300 U.S. dollars), and the direct use application for heating could result in savings of 230,000 yuan per day (≈$35,000 U.S. dollars).[126]

Last, a study by Zhang et al.[127] looked at harnessing waste heat from thermal EOR through different thermodynamic cycles such as the organic Rankine cycle and the Kalina cycle (KC). For this study, a thermodynamic analysis was performed to determine the effects of properties such as the turbine inlet temperature (TIT), evaporation pressure, and the compression

Table 9. Summary of Research in the Study of the Application of Geothermal Resources with Operations of Enhanced Thermal Recovery of Oil in Oilfields

title	authors	year	EOR method	power and thermal output/efficiency	energy utilization system	energy carried fluid	country
letting off steam and getting into hot water-harnessing the geothermal energy potential of heavy oil reservoirs	Teodoriu et al.[118]	2007	steam flooding, hot water flooding	24 kWe, 195 kWt/12%		water	
artificial geothermal energy potential of steam-flooded heavy oil reservoirs	Limpasurat et al.[117]	2011	steam flooding	134 kW		water	
cascade utilization of waste heat in heavy oil exploitation by SAGD technology	Liu et al.[126]	2013	steam assisted gravitational drainage	43,679 kW	ORC	water	China
creating enhanced geothermal systems in depleted oil reservoirs via in situ combustion	Cina[55]	2013	in situ combustion	11,000−3000 kW	geothermal flash plant	water	
modeling of geothermal power generation from abandoned oil wells using in-situ combustion technology	Tian et al.[56]	2018	in situ combustion	200−120 kW	ORC	water	China
the numerical simulation and wellbore modeling of steam injection and stored heat recovery from a light oil reservoir	Zafar et al.[123]	2021	steam injection	1831−708 kW		water	Pakistan

ratio on the combined SAGD/ORC and combined SAGD/KC systems.[127] In general, the results showed that the SAGD/ORC net output power values are higher than those obtained in a SAGD/KC system operating on the same heat source. A higher TIT results in an increase in the net output power and lower power output values for the KC unit due to the two-phase flow that occurs at the exit of the turbine. Conversely, an increase in evaporation pressure in the SAGD/ORC unit increases the net power output, while the SAGD/KC net power output decreases as evaporation pressure increases.

The investigations reviewed in this section allow us to see that the TEOR processes are complemented when using geothermal resources by having high temperatures available in the reservoir that allow the heating of fluids. Even though all of the investigations refer to modeling and simulation of the processes, this is a good start for implementing the first real-world pilot in the future. Table 9 summarizes the application of geothermal resources with operations of enhanced thermal recovery of oil in oilfields.

7. OTHER RENEWABLE ENERGIES AND TECHNOLOGIES INSTEAD OF ORC COUPLED TO THE OIL AND GAS INDUSTRY

Wind power, solar, and hydropower are the most studied and widely deployed renewable energy sources.[8−12] Wind power converts the wind's kinetic energy to power through wind turbine systems, whose principal components are rotors with turbines, electric generators, and electronic power converters. Solar power is derived from the sun and maybe harnessed for electrical generation or direct use applications where a heat source is needed.[13] Solar power is mainly derived from concentrated solar power or photovoltaic cells. In concentrated solar power, heat or electricity is generated by coordinating an array of mirrors that concentrate sunlight to heat a solid or fluid to temperatures up to 1000 °C.[13] On the other hand, photovoltaic power uses photovoltaic cells, mainly consisting of silicon compounds, that directly convert sunlight into electricity.[13] Lastly, hydroelectric power is a renewable source that uses hydraulic potential energy to generate electricity or mechanical movement.[14] It is currently estimated that power generation for wind, hydro and solar resources will grow from 1272, 4513, and 332 TWh to 2681, 5677, and 846 TWh by 2035, respectively.[15]

Nevertheless, solar and wind power present several disadvantages. Wind power has historically been an expensive technology dependent on climactic forces that give variable and unpredictable electrical output[16] Further, owing to issues related to energy storage, wind power is challenging to integrate into conventional power grids.[17,18] Also, the remoteness of many wind power sources further complicates its integration, as many favorable locations to produce wind power are far from existing power grids, requiring additional investment in transmission to bring this power to market.[9] The impact of wind power on the environment is non-negligible. In addition to the noise pollution and landscape considerations of wind turbine operation, they are also known to negatively affect fauna, including insects and birds.[10,13] On the other hand, despite energy from the sun being enough to supply 7900 times world energy demand, several challenges stand in the way of solar power realizing its full potential.[13] As with wind power or hydropower, solar power relies on climatic conditions to produce electrical power.[19] Solar power depends on solar radiation, diurnal cycles, temperature, humidity, and wind speed.[13,20] In the environmental issues, the minerals required in the construction phase and the structure in solar and wind energy are of significant impact. At the same time, hydropower is critical in the CH_4 emissions for submerged vegetation and flooded land in the construction stage.[21,22] Among the renewable energy sources, geothermal energy does not require technologies that require periodic modification due to climatic changes or the use of minerals with a significant environmental impact in their extraction.[23]

It is estimated that 43 million EJ of geothermal energy is stored within 3 km of the earth's surface that could be converted to approximately 1.2 billion TWh of power.[24] This quantity is a clear demonstration of the potential of geothermal energy for power generation, and unlike other sources of renewable energy, the supply of energy can be constant and climactically independent.[25] Some disadvantages in the application of geothermal energy are the high costs justified by exploration and drilling of wells and the uncertainty of finding sources with high quality that justify the start of a project.[26,27] The application of geothermal energy is not simply limited to electrical generation. Geothermal heat is harnessed in many residential and commercial applications that directly use the heat or concentrate the heat as in geo-exchange technologies such as the heating of crude oil to facilitate the

https://doi.org/10.1021/acsomega.2c04374
ACS Omega 2022, 7, 40603−40624

transport of the fluid,[28] heat exchange in process and service fluids,[29−31] among other applications.[32]

In the oil and gas industry, the temperatures of produced fluids, depending on reservoir conditions, can be classified as medium enthalpy (temperature between 90 and 150 °C) or low enthalpy fluids (temperatures below 90 °C) geothermal resources.[35] If the temperature of produced fluids is at least 70 °C, electricity generation is considered feasible. Otherwise, the resource may only be helpful in direct-use or geo-exchange applications.[36]

Medium and low enthalpy fluids can generate electricity by installing binary cycle power plants. In its most basic form, a binary cycle power plant consists of an evaporator, expander, pump, condenser, and heat source.[37−40] Throughout the world, countries such as Germany,[41] France,[42,43] the United States,[44,45] Indonesia,[46] Austria,[47,48] and Portugal[49] have used the organic Rankine cycle, a form of binary-cycle power generation technology, which stands out as the primary mechanisms for electrical production from geothermal resources. The ORC's working principle is like the conventional Rankine cycle. Instead of water, the working fluid is an organic fluid with a higher molecular mass and a lower boiling point than water.[38,39]

Geothermal energy is a power source with relatively low environmental impacts such as land transformation[25] and greenhouse gas emissions generation. On average, conventional geothermal plants (flash or dry steam) produce 8.2 kg CO_2 MWh^{-1}, while solar, wind, and hydropower produce 1.1, 0.02, and 0.8 CO_2 MWh^{-1}, respectively.[50] However, binary power plants produce virtually zero emissions[25] due to their closed-loop configuration where the fluid is constantly reused, avoiding direct exposure of organic working fluids to the environment. This renewable source has one of the lowest carbon footprints compared with fossil fuel sources and other renewables.[25] Geothermal fluids are usually reinjected into the reservoir to avoid discharge subsidence (gradual caving in or sinking of an area of land) or dissolved solids.

8. CHALLENGES AND PERSPECTIVES

A recent review of the power generation from geothermal resources as a co-product of the oil and gas industry focuses on the technical potential and environmental advantages of using geothermal resources in the oil industry. However, the specific characteristics necessary to take advantage of technologies, such as the ORC, must be considered. Based on the above-mentioned considerations, the following challenges are considered in the oil industry for the widespread use of geothermal resources:

- The development of technologies that efficiently use the geothermal resource: This type of technology has thermal efficiencies between 3 and 12%,[67] improving the economic performance and environmental behavior
- The development of more compact devices: the space of the technology available in the field is of considerable importance[75] in reducing multiple impacts generated by the natural land occupation and transformation.
- Use of low enthalpy resources: the technologies currently in the market have flow and temperature restrictions where most require resources of >80 °C. The development of organic fluids that use lower temperature sources would help in the spread of this technology.

Furthermore, the use of innovative technologies, such as nanotechnology, can promote the spread of these technologies for geothermal resources use in the oil industry. Nanotechnology has been applied in the oil industry in different pilots with promising results.[128]

As stated previously, the geothermal industry has certain similarities, relating to equipment and operations, with oil and gas. Nanotechnology has been used in the petroleum industry for many applications where some of them are related to enhanced or improved oil recovery,[129−133] heavy oil upgrading,[133,13] and formation damage.[133] Nanotechnology is employed in geothermal projects to improve heat exchange,[135−137] as noncorrosive coating,[135] and to prevent formation damage.[138,139] Therefore, in the petroleum industry, improvement in nanotechnology can be used to develop geothermal resources as an additional product.[140,141]

The effects in productivity and injectivity associated with variations in permeability because of mobilization, migration, and retention of fine particles are important for geothermal and oil and gas industries.[142] As possible solutions to fine migration using nanotechnology, Diez et al.[143] developed nanofluids based on hexadecyltrimethylammonium bromide and MgO nanoparticles, which are capable of retaining fine particle migration. Furthermore, Mansour et al.[144] examined the modifications on the sandstone surface from the Abu Rawash reservoir by the adsorption/desorption of MgO and SiO_2 nanoparticles to reduce migration of fine particles. Thus, investigating the problems of fluid production and how nanotechnology can help solve these issues to improve fluid production at high temperatures for energy production.

Furthermore, the water produced in petroleum or geothermal wells contains dissolved ions that can cause inorganic scales in pipes, valves, surface facilities, and heat exchangers,[145−148] resulting in turbulent flow regimes, increase in pump requirements, and reduction in the heat exchange efficiency and finally increase in operating costs.[148−150] The use of binary power plants requires heat exchange between a relatively hot geothermal and colder liquid, which decreases the geothermal fluid temperature and may reduce the solubility of dissolved ions, thus resulting in supersaturation and scale formation[150,151] throughout pipes or equipment. Disturbances cause precipitation in chemical equilibrium because of changes in temperature, pressure, pH, or incompatibilities.[152,153] Scale precipitation has been reported in geothermal systems, such as Tuzla, where Galena and $CaCO_3$ scales were reported in the downhole and surface pipelines, whereas sulfide-based scales were reported only in the downhole.[154] Soultz-sous-Forêts geothermal site in France presented scaling problems, where Ba/Sr sulfates are precipitated in the heat exchangers during the process of thermal transfer,[155,156] which is associated with the circulation of geothermal brine with high salt content (97 g L^{-1}) where scaling is more evident in the coldest part of the power plant.[151] Moreover, geothermal wells in the Bavarian Molasse Basin presented considerable problems of scaling, which were associated with the requirement to change the pump seven times in two years because of technical problems where calcite was the main precipitate identified.[157] The reduction in $CaCO_3$ solubility was related to decompression and stripping of CO_2 from the geothermal water. Moreover, in the Pleasant Bayou geopressured system, where water and natural gas were co-produced, scales precipitation and corrosion through the system were minimal because of the addition of inhibitor, despite the brine's high salinity,[111] thus

https://doi.org/10.1021/acsomega.2c04374
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demonstrating the requirement to consider chemical products to inhibit or remediate this type of problem.

Several studies demonstrated nanotechnology as a possible alternative to control the formation of inorganic scales. Inhibition treatments developed in the oil industry may be suitable for geothermal co-production projects because most common oilfield scales, such as calcite, sulfates, and sulfides, are present in geothermal projects.[14] Luo et al.[158] prepared an antiscale nanoemulsion using a fatty acid methyl ester sulfonate as the surfactant, biodiesel fuel as the oil phase, and a commercial-scale inhibitor as the water phase. The results demonstrated that the efficiency might reach 89.6% with an absence of flocculates, and its antiscaling capability was justified because of good absorbability, slow desorption rate, and great retention. Franco-Aguirre et al.[159] synthesized and evaluated Ca-diethylenetriamine pentamethylene phosphonic (Ca-DTPMP) nanoparticle-based nanofluids as an inhibition and remediation treatment of the formation damage caused by $CaCO_3$ precipitation. Thus, an inhibition efficiency of 67% was obtained, and the nanofluid increased by 57% in permeability compared with the undamaged case and obtained an increase in volume recovery of 4 and 24% compared with the base and damaged cases, respectively.[159] Moreover, Jiang et al.[160] prepared a superhydrophobic CuO nanowire layer used as an inhibitor for $CaCO_3$ precipitation to avoid performance drop and obstruction of heat exchangers. Copper anodization was used to synthesize this nanostructure in a NaOH solution to develop a microstructure adjusted using FAS-17.[160] The weight of deposited $CaCO_3$ scales was reduced from 0.6322 to 0.1607 mg cm^{-2}, demonstrating the antiscaling effect of the CuO nanowire surface.[160] However, magnetic nanocomposites were synthesized by Do et al.[161] and were capable of inhibiting calcite-scale deposition up to 63.64%. The research presented, with the requirement to avoid damage to fluid transport and heat transfer systems, makes it necessary to investigate more solutions, such as nanotechnology, to improve energy production systems.

Nanoparticles are applied to enhance convective heat transfer and conductivity of working fluids, thus avoiding problems associated with sedimentation, erosion, clogging, or pressure drop.[162] Abbasian Arani et al.[163] performed an experimental investigation of the effect of volumetric particle fraction on heat transfer properties of TiO_2-distilled water nanofluids. In this study, a peak thermal performance factor was obtained using TiO_2 distilled water nanofluids with 0.02% and a Reynolds number of 47,000. For geothermal applications, Diglio et al.[164] presented a numerical study in which different nanofluids with low volumetric concentrations were evaluated to replace ethylene glycol/water mixtures as heat carriers in borehole heat exchangers. Criteria for selecting the best nanofluids were based on the nanofluid that ensures the highest decrease in borehole thermal resistance and lowest pressure drop increase. Nanoparticles of copper, copper oxide and alumina, silver, silica, and graphite were compared. Among all analyzed nanoparticles, Cu demonstrated thermal reduction values between 3.5 and 3.8%, thus changing the concentration between 0.1 and 1%.

Sui et al.[137] investigated by simulation the potential use of nanofluids as heat exchange fluids in geothermal systems using abandoned oil wells recompleted as heat exchangers. Because of the enhancement of thermal conductivity and heat exchange caused by nanoparticles. Al_2O_3 nanofluids was used as a working fluid and was compared with a case where water was used as a heat carrier in the geothermal system. In terms of extracted heat, at low flow rates, differences between using water or the nanofluids as carrier fluid are negligible, whereas at high flow rates, as extracted heat by nanoparticles is 11.24% higher than extracted heat using water as working fluid.[137] The study presented demonstrates how from nanotechnology, the thermal properties of fluids can be improved, thus seeking greater efficiencies in the use of geothermal resources.

Finally, the environmental impact of this type of process must be considered. Studies that quantify and explain the environmental impacts of the use of geothermal resources in the oil industry are required for the implementation of the variable methodological tools such as life cycle assessment, material flow analysis, exergy, and energy analysis.

9. CONCLUSIONS

Many possible co-produced fluid geothermal energy applications in oilfield developments represent an exciting new frontier for the geothermal industry and the upstream oil and gas industry. Microgeneration increases the possibility of electrical power self-sufficiency for oilfield operations. Many studies suggest that these applications may benefit local communities by supplying excess electrical power or the direct use of the heat in agricultural, industrial, or residential settings. This review demonstrated that abandoned modified petroleum wells be used as exchangers to extract geothermal energy from depleted reservoirs using a carrier fluid. Thermal EOR techniques used for heavy oil extraction, such as ISC, steam-flooding, or SAGD, thus unwittingly creating an opportunity for heat recovery. Waterflooding the heated rocks and channeling this fluid to binary cycle power-generation equipment provides an opportunity to improve the overall energy efficiency of these undertakings. Moreover, the high temperature of co-produced fluids in certain oilfield developments, even without thermal EOR, can be sufficient to produce electricity; the success of two long-term pilots is proof of its potential.

Despite the synergies identified between geothermal and oilfield development that should encourage proliferation of co-produced fluid geothermal energy, many studies focused on modeling or simulation studies. More efforts should be made to conduct pilot tests to demonstrate the proper feasibility of this type of project and gain the practical experience that will show skeptics that this technology is as beneficial as the large body of literature suggested.

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https://doi.org/10.1021/acsomega.2c04374
ACS Omega 2022, 7, 40603−40624

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■ ACKNOWLEDGMENTS

The authors acknowledge MINCIENCIAS, Parex Resources Colombia Ltd., and the Universidad Nacional de Colombia for their financial and logistical support. This research was funded by MINCIENCIAS under project number 7995-869-76099.

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https://doi.org/10.1021/acsomega.2c04374
ACS Omega 2022, 7, 40603−40624