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POWER GENERATION FROM WASTE HEAT DURING OIL PRODUCTION

by

SUBRAHMANYA CHANDRA BHAMIDIPATI

A THESIS

Presented to the Graduate Faculty of the

MISSOURI UNIVERSITY OF SCIENCE AND TECHNOLOGY

In Partial Fulfillment of the Requirements for the Degree

MASTER OF SCIENCE IN PETROLEUM ENGINEERING

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Approved by:

Dr. Ralph Flori, Advisor
Dr. Baojun Bai
Dr. Shari Dunn Norman

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ABSTRACT

The increase in the world population is causing a significant increase in the global demand for energy. This rise in demand is generally met with the use of fossil fuels. But there is considerable pressure to lessen the release of carbon through the combustion of fossil fuels. One way that the oil and gas industry can provide increased energy without carbon combustion is by extracting the latent heat energy contained in produced oil, gas and water from producing reservoirs, and from water which is cycled through depleted, end-of-life or abandoned reservoirs. Extracting this energy and using it to provide direct heating to various industries and homes or to generate electricity using Rankine Cycle technology have great potential as a carbon-free energy source. The potential of this technology is especially compelling because it takes advantage of already existing oil and gas well infrastructure and expertise.

The aim of this thesis is to explore the potential geothermal energy that could have been produced from the Volve Field using the coproduced fluids. The Volve Field is a deep, offshore North Sea oil reservoir at depths of around 9,500 feet. The produced fluid temperature of the Volve Field is around 80°C, which shows a potential electrical output of 1MW per well. Different wells of this field were compared with other wells from other fields, namely the Wytch Farm and Wareham Fields in the UK.

ACKNOWLEDGMENTS

I would like to extend my deep and sincere gratitude to my research advisor Dr. Ralph Flori for his guidance and encouragement, for mentoring and supporting me, and for his help improving my writing.

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1. INTRODUCTION

The oil and gas industry is one of the largest commercial sectors in the world. It includes the process of exploration, extraction, refining, transporting and the marketing of petroleum products. Petroleum is the world's largest and least expensive sources of energy, and it serves as the raw material for many chemical products. This industry, in terms of dollar value, generates an estimated of $3.3 trillion in revenue every year.

In 2019 alone, the world produced and used an average of 82 million barrels of oil per day. This oil is produced from petroleum reservoirs deep below the earth's surface. A common misconception is that these oil reservoirs exist within the earth as large pools from which oil is extracted but, the crude oil, is contained in porous rock formations. Drilling an oil well into these porous rock formations allows the petroleum to flow from within the rocks to the well. This flow is ensured by maintaining the well at a lower pressure than the pressure deeper in the reservoir.

In a typical oil reservoir, with the help of wells, only around 15-20 percent of the oil is produced with the help of the natural reservoir energy. Initially, the reservoir pressure is high, but this pressure decreases as the oil is produced and this ultimately decreases the differential pressure. This type of recovery is known as primary recovery. To ensure that the production continues, we should either decrease the bottomhole pressure or increase the differential pressure by maintaining the reservoir pressure. The second stage of petroleum production consists of the injection of an external fluid, usually water or gas into the reservoir through drilling injection wells into the reservoir. The purpose of doing this is to maintain the reservoir pressure and help displace the hydrocarbon towards the wellbore. This type of recovery is known as secondary recovery. This stage produces another 10 to 20 percent of the original oil in place. This stage reaches its end when the fluid injected is produced in significant amounts (for example, injection water can approach 98 or 99 percent of the total production stream) in the production wells. Where economical, in some fields engineers implement a third stage (called tertiary recovery or Enhanced Oil Recovery (EOR) or Improved Oil Recovery (IOR)). This third stage of hydrocarbon production usually follows the waterflooding. It involves techniques like chemical flooding, CO_2 injection, thermal injection, and other methods. This stage produces an additional 5% to 25% of the original oil in place.

Figure 1.1 depicts cumulative oil recovery versus time and shows primary, secondary, and tertiary recovery stages. It also shows the sharp increase in the producing water-oil ratio (WOR) late in the life of a reservoir due to high volumes of produced injection water and the relatively low oil production rates.

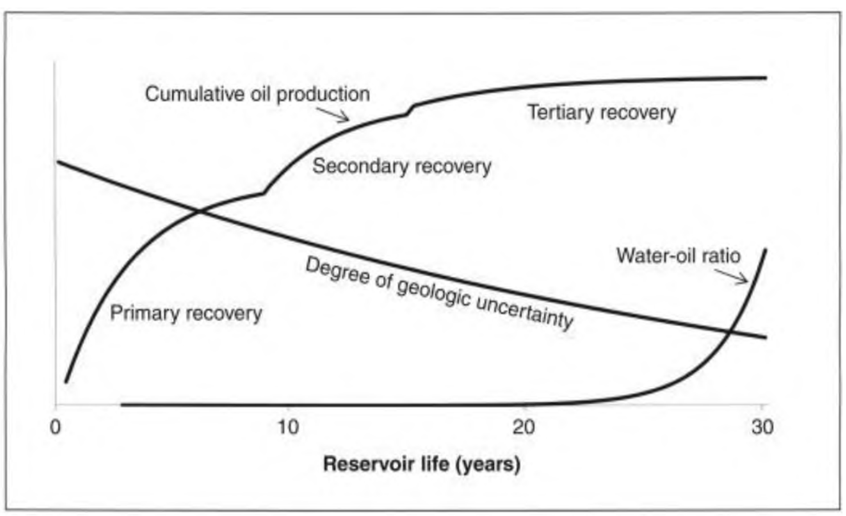

Figure 1.1: Oil reservoir life cycle and fluid recovery
(Courtesy: Abdus Satter, Ghulam M. Iqbal, in Reservoir Engineering, 2016)

Typical oil reservoirs are located deep within the earth's surface. There are some fields in the Gulf of Mexico that produce from oil reservoirs at true vertical depths of 28,000 ft. The deeper the well, the hotter it gets. The reason for this is that the earth's core temperature is approximately 5,200° C (or 9,000° F). Because of this extreme temperature difference between the earth's core and its surface, considerable thermal energy flows outward from the Earth's core. Oil and gas reservoirs, at typical depths have bottomhole temperatures from 60° C to over 150° C, depending on the temperature gradient in that particular area. Clearly there is a massive supply of thermal energy below the earth's surface. This thermal energy in the primary source of energy for geothermal wells.

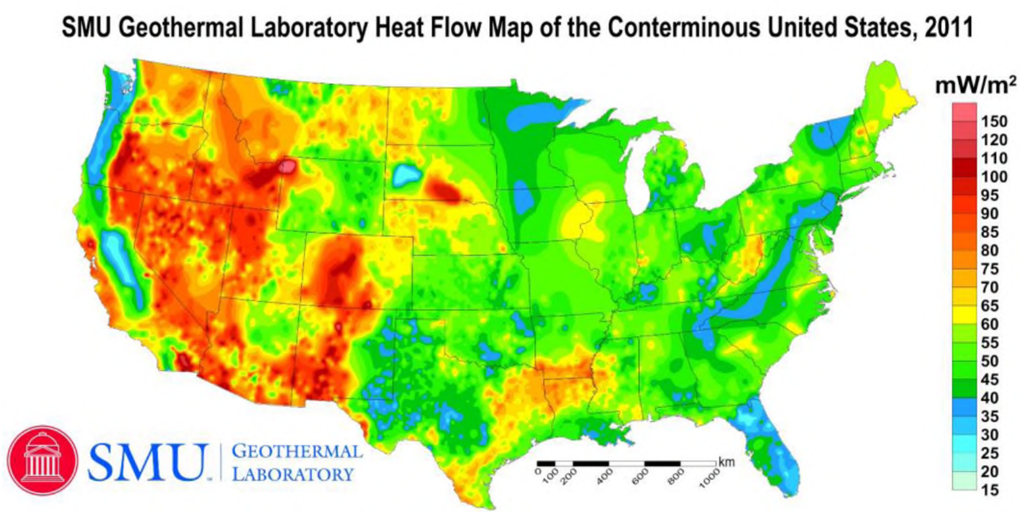

Figure 1.2: Heat flow map of the Earth's surface in the United States
(Courtesy: SMU Geothermal Lab)

To illustrate the geographical variations in heat flow to the surface, Figure 1.2 depicts a heat flow map of the Earth's surface in the United States. The regions marked in red show a higher amount of heat flowing through them, while the regions in blue have a lower amount. Oil and gas wells in the high heat flow regions will have higher bottom hole temperatures and will be better candidates for the extraction of geothermal energy. Wells in the lower heat flow regions will be poorer candidates for geothermal energy extraction. California, Colorado, Arizona and Texas are some of the states in which there is higher heat flow and higher bottomhole temperatures.

A study by the US Department of Energy[7] has estimated that there are around 20 billion barrels of water that are co-produced along with oil and gas per year in the United States alone. Out of these 20 billion barrels, around 4 billion barrels of water have a temperature of 80°C or higher. As water has a high specific heat, it has the potential to store lot of heat energy and this heat energy from the co-produced water could be extracted from the water. Figure 1.3 shows the key takeaways of the study.

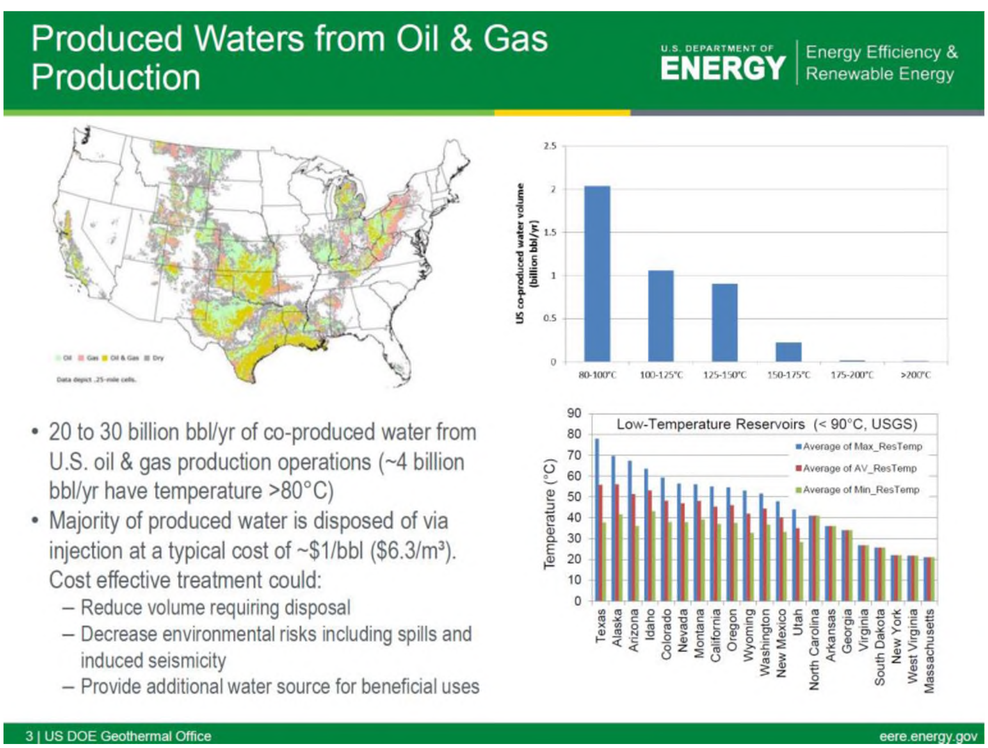

Figure 1.3: Produced waters from oil and gas production (from eere.gov)

The main purpose of this thesis is to explore the extraction of heat energy from these wells. This can be done during two periods—the normal oil and gas production period, and afterwards. During the normal oil and gas production stage of these wells which can last for a period of a few years, the heat contained in the normally produced oil or gas and any accompanying water can be extracted.

After oil and/or gas production has declined to uneconomic levels, thermal energy can also be extracted for a longer period of time through cycling injection water through the reservoir where it acquires heat, producing the water, extracting the heat and reinjecting the water. This latter stage, where injection water is cycled, can be done in abandoned fields, especially if these fields still have infrastructure like wells, completions, production facilities, etc. There are around 29 million abandoned wells around the world. Utilizing these reduces costs in not drilling and completing new wells for geothermal energy.

There are multiple ways to harness this thermal energy. The main focus of this thesis is the conversion of this energy into electricity using a Rankine cycle process, but the hot fluids that are produced from these fields can be used for direct heating purposes as well. There are many possible ways to utilize these hot fluids for direct heating, for example for residential and/or commercial heating. Direct heat can also be used for industrial purposes like for a boiler feed pre-heating. They can power greenhouses and can be used for maintaining the temperatures of aquafarms. This is an efficient way of utilizing this energy since there is no heat lost in converting this energy to electricity.

This geothermal energy from the reservoir fluids is a clean and green source of energy. There is little to no carbon footprint involved in generating this energy because it does not involve the purchase and the burning of fluids to produce any greenhouse gases.

This energy from the produced fluid is a "free lunch" in that it is energy that the fluid already possesses and is generally going to waste as the production fluids pass through surface production facilities. The already established infrastructure in the oil and gas production and processing industry can be used to avoid high initial costs to make this technology economically feasible. This technology also creates a potential new, valuable use for abandoned oil and gas wells.

Based on the results of this thesis, the energy generated from the produced fluids and the sustained injection of fluids is comparable to other renewable sources of energy like solar energy and the wind energy. This energy does not require any batteries to store the energy as the energy comes already stored within the reservoir and we are using the fluids to bring the energy out of the reservoir. This source of energy is a continuous source of energy as there is always heat flowing within the earth's surface and is not affected by the weather and the wind speed like that of solar and wind energy.

If these hot fluids are to be used to generate electricity, equipment utilizing the Rankine cycle is used. Figure 1.4 shows a schematic of the Rankine cycle used to generate electricity. The Rankine cycle consists of four major components—an evaporator, a turbine, a compressor, and a pump. A working fluid cycles through these components. The evaporator collects the heat from the produced fluids and transfers it to the working fluid. This working fluid then vaporizes and goes through the turbine. It turns the blades of the turbine which is connected to a generator producing electricity. The working fluid then goes into the compressor where it is converted into a liquid and is then sent into a pump to go into the evaporator.

Traditional Rankine cycle equipment operate at a temperature of around 200°C and above and use water/steam as the working fluid. These temperatures are too high for fluids produced from oil and gas reservoirs to achieve and hence a working fluid with a lower operating temperature range is used. Some of the fluids that can be used are propane, iso-pentane and refrigerants. Since there fluids are of organic origin, this type of Rankine cycles is known as an organic Rankine cycle. This organic Rankine cycle is used with the extraction of the geothermal energy from the injected and produced fluids in this thesis. Organic Rankine cycle equipment has an approximate 10 percent efficiency in converting heat temperature to electricity.

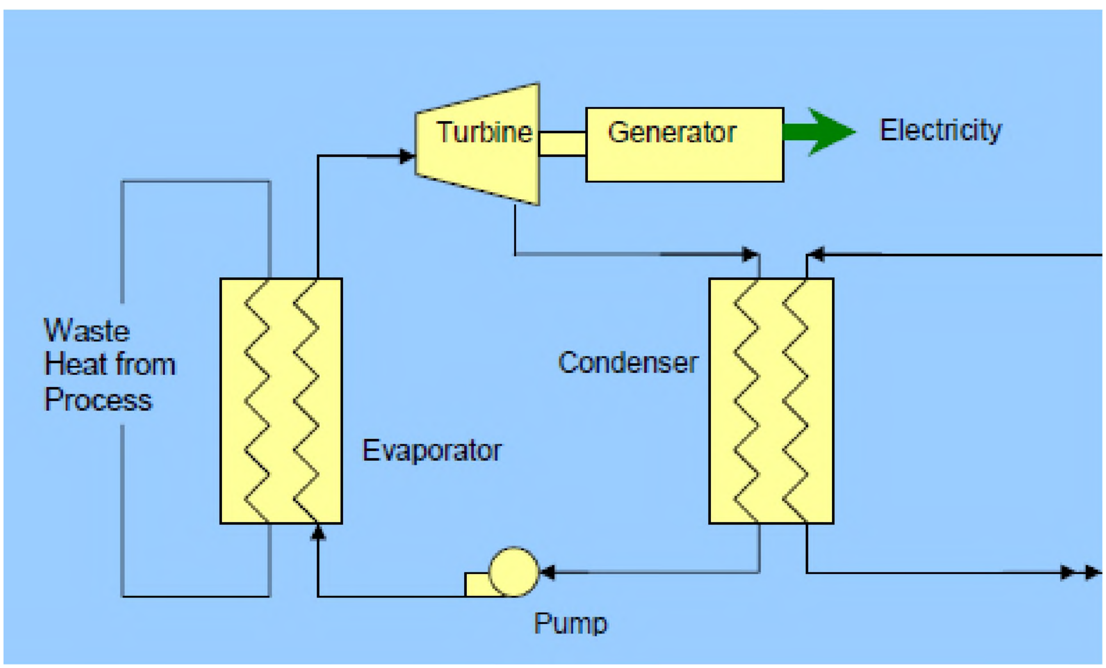

Figure 1.4: Schematic of a Rankine cycle used to generate electricity
(Courtesy: US Department of Energy 2016)

This thesis utilizes data from the Volve Field, which is a North Sea field in the Norway sector. These data were recently made public. Various calculations have been made with assumptions to see the potential of this energy generation technology. Both the energy from the produced fluids and energy from the sustained injection of fluids after the abandonment of the field prove to be economically feasible and the exact numbers and calculations are found in the following sections.

2. LITERATURE REVIEW

A strong foundation of research has been done in the area of extracting geothermal energy generated from oil and gas reservoirs. The majority of the authors found it to be economically viable. Various basins across the world have been studied and various uses for the extracted energy were found.

A study by Kara P. Bennett, et al.[3] discussed the use of binary cycle power plants in the Los Angeles basin. They reviewed the bottomhole temperatures of the many oil fields in the LA basin and identified fields have good potential to use the already available infrastructure from oil production to generate electricity. The LA basin has a geothermal gradient of 36°C/km and over 30% of the oil reservoirs are as deep as 6,000 ft which corresponds to a bottom hole temperature of at least 80°C. The LA basin also had a long history of water flooding along with steam flooding. Most of the oil fields in this basin are close to cities with easy access to the electrical grid. The Wilmington oilfield was highlighted as an attractive candidate for utilizing coproduction. This is the second largest field in the state of California and has a water cut of 97%. This field has deep wells that reach around 8,200 ft with recorded bottomhole temperatures of 140°C. This paper also describes a process of screening potential candidates for coproduction. A simple STARS model was made to forecast the performance of the reservoir over 30 years and the power output from the binary plant was calculated. These results were then used in an economic model to calculate the Net Present Value of the project. Overall, the authors concluded that the LA basin contained a significant number of oil reservoirs with sufficient temperatures so that electricity can be generated economically with the binary Rankine cycle. Their conclusion was that all the fields along with all of the wells combined together have the potential to produce 8.2 MW for 30 years, assuming an outlet temperature of 55°C.

A study by Sean M. Watson, et al.[5] reviewed the onshore wells of the South UK basin to explore the potential for the decarbonization of the heat supply by using oil wells for the generation and storage of geothermal energy. Of the 2,000 onshore hydrocarbon wells, around 550 had the potential to be repurposed, and of these 292 were operating at that time. All the fields studied in this paper were ranked on their potential for geothermal repurposing. The Wytch Farm and Wareham Fields were chosen by the authors for a detailed analysis. The production field temperature of the Wytch Farm Field was around 65°C, but it had a production rate high enough to generate a thermal output of 90 MW that was economically viable. The authors concluded that if this energy was produced by the burning of natural gas, it would be valued at around $125,000 per day. The thermal output for each field was calculated based on numbers that were obtained from decline curve analyses as the field were still producing. The Wytch Farm and the Wareham Field lie in the rural areas of the UK and hence the potential energy produced by these fields had greater likelihood to be used in the agriculture and horticulture sector. Based on the ambient temperature around the Wytch Farm Field, the generated energy could be utilized in heating greenhouses which can produce vegetables such as peppers, tomatoes, cucumbers. With a conservative estimate of the temperature differential, the Wytch Farm Field can generate enough energy to power around 76 greenhouses that are rated at 595 kW. The authors also considered using this geothermal energy to heat residential and commercial swimming pools. They concluded that the Wytch Farm Field provided enough energy to heat 100 swimming pools. The Wareham Field did not have enough flow rate for the thermal output to be economically feasible.

Research by Elena Soldo, et al.[6] investigated three different case studies in Italy where the local energy demand is taken into consideration and the geothermal energy from utilization of onshore hydrocarbon well systems is calculated. An approach for conversion of energy from the producing wells was proposed. The Villafortune-Trecate case study had one well that was feasible for power generation. It had a wellhead temperature of 130°C and was supplying fluids at a rate of 100 kg/s. The produced fluid was first fed to an organic Rankine cycle plant where maximum energy was extracted, and the exiting fluid is assumed to have a temperature of 80°C. This is high enough send the same fluid to the District Heating (DH) plant. The fluid then exits this plant at 50°C and is used for aquaculture purposes. The aquaculture plant selected in these case studies was shrimp which need a constant supply of water at 35°C. The produced geothermal fluid exiting from the DH plant was used to extract heat to provide energy for the aquaculture ponds. The annual revenues based on the economic analysis led to the conclusion of recovering the initial investment in around 5 years. The power plant was estimated to produce 30,000 MWh, and the second-step DH plant would generate enough heat for an average of 8,000 people. Another case study included the oil field in Gaggiano. This field has a flow rate of $50m^3/h$ and had a well head temperature of around 125°C. There were two producer wells and once injection well. A total thermal power output of 6MW from both the wells was generated. After assuming around 2kW per person, the DH plant was able to generate enough energy to provide for 40% of the inhabitants of Gaggiano. Using the same parameters, the time taken to recover the initial investment in this field is around 7.5 years.

The third and final case study was in the Irminio oil field. The fluid in this field was used to generate biogas and biomass for the production of biodiesel. The majority of the energy from the co-generation plant was used to produce algae. Considering all aspects of this cast study, the economic analysis revealed that the initial investment can be generated in around 5 years.

A study done by Al Saedi, et al.[15] presents an analytical model for estimation of heat flowing into the well from the fluid flow. It utilizes this model to convert the fluid flow rate into the heat-flow rate with the integration of the Joule-Thompson effect. This is combined with the Darcy flow equation and the Fourier's heat flow equation to result in a heat flow rate into the well. From the heat flow, the well head temperature was calculated. This paper validates its model with the help of data from multiple wells. The model is capable of handling different rate sequences and hence is useful in various real life scenarios.

A study by Crowell A., et al.[1] discussed various US petroleum basins and their potential for geothermal energy generation in the United States. Different basins were studied, and their potentials were evaluated. The area from Denver to Greeley has the best potential for geothermal energy in the Denver basin. This is very close to many populous areas in the state of Colorado and hence has access to already established infrastructure. The total geothermal energy in place in the Denver basin was estimated to be around 90,000 GW. The Illinois basin and Michigan basin were also evaluated for their potential for geothermal energy. The basins were split into different groups where the temperatures of the producing layers were classified. The Michigan basin had temperatures over 90°C while the Illinois basin has had only area with temperature that was over 90°C. For this reason, the Illinois basin was omitted from further study as a source of geothermal power production. Using the same calculations as done for the Denver basin, the authors concluded a huge total energy of 18,000 GW was possible within the Michigan basin.

A 1973 paper by Jefferson W. Tester, et al.[4] discussed the generation of electricity from hot dry rock geothermal energy. They also delved into the technical and economic issues that arise in the generation of electricity, and they proposed some solutions to the problems. The effects of reservoir degradation, variable fluid flow rate and drilling operations were studied to determine the best strategy for economic feasibility. Water was injected in low permeable formations, creating fracture paths that had a sufficiently large heat transfer surface area. If water was injected in high permeability formations, the techniques for the extraction of the water were more demanding. The effect of this on the reservoir performance was studied in detail. Equations were developed in which the recoverable power was estimated using the mass flow rate of water flowing into the wells. With the help of these equations and considering the limitations of the technology, i.e. the efficiency of binary Rankine cycles, the optimum geothermal fluid flow rate was estimated as a function of the fluid temperatures. This formed a baseline for fields to consider if they were to produce geothermal energy from the reservoir. Economic analysis was also done using these calculations and the authors were able to conclude that this technology was to be successful with a geothermal gradient of 40°C/km.

A paper by Ngoc Tran, et al.[11] studied the geothermal energy in the Oklahoma region as a potential source for electricity generation. This paper discussed various economic concepts to provide heating and cooling of the Well Construction Technology Center at the University of Oklahoma. It discussed the design and economics of multiple geothermal options viz, shallow depth geothermal wells, resuming production of an abandoned well, and a single well injector/producer system. The analysis revealed that all the options were not economically feasible for 2019's cost of energy. The options generated a negative NPV and the payback periods were multiple decades. Of all the options review in this paper, the authors found that in the Oklahoma basin, the drilling of shallow geothermal wells was the highest value generating option.

A study done by Subir KS, et al.[9] discusses general kinds of wells that have the potential to supply geothermal energy for the generations of electric power. This paper presents the technical and economic aspects of power generations from each of the types of wells, includes case histories and conducts economic assessments for commercial developers and operators. The authors designed a conceptual hybrid system which produces power from both water and the gas. A gas well from the US Gulf Cost was presented in the paper. It was concluded that the power generation from the well is economically viable. The well generates an estimate of 3.9 MW of which 1.5 MW is from the geothermal energy and 1.9MW is from the produced methane and 0.5 is from the kinetic energy of the fluid. If the gas price is high enough, the authors concluded that it would be more profitable to sell the gas rather than generate electricity by consuming it.

A study done by the US Department of Energy[7,8] analyzed the total amount of energy consumed by the Unites States and assesses the waste energy released by the US industrial sector. It was estimated by the authors that somewhere between 20% to 50% of the industrial energy input is lost as waste heat in the form of exhaust gases, cooling water or heat lost from hot equipment surfaces. As the industrial sector is improving its efficiency, energy extraction from the waste heat proved to be an attractive opportunity for a cleaner and greener source of energy. This study reviews the RD&D for improving the waste heat recovery technologies. The approach used is a bottom-up approach to calculate waste heat quantity, quality, practices for recovery and barriers of technology. The needs for technology were identified in two categories: i) extending the range of existing technologies ii) exploring new methods for waste heat recovery. They studied heat recovery in various applications such as furnaces, boilers, kilns, steel and glass industry. The energy consumed a sum of 8,400 TBtu/yr which is around one-third of the energy delivered to industries. Majority of the furnaces operate at a efficiency below 50% since they have high exhaust temperatures. A significant quantity of low temperature waste heat is available in cooling water. The energy content of waste streams was calculated based on assumptions made by the authors. The waste heat losses contained in exhaust gases in this study were reported to be around 1.5 quadrillion Btu/yr. Based on the ambient temperature, the work potential of all the waste heat is estimated to be around 600 TBtu/yr.

A study by Xiaolei Liu, et al.[10] discusses harnessing low-temperature geothermal energy from oil and gas reservoirs. In this paper, the oil and gas reservoirs around the world are critically reviewed for waste heat recovery. Reservoirs where heat recovery has already been tested, or has potential, were also reviewed. Based on the results obtained by the authors, a roadmap of screening criteria based on the geological, production, and economic parameters was suggested to quantify if the low temperature waste heat recovery is economically viable. This roadmap was tested against the Villafortuma-Trecate oil field in Italy which has an aquifer that also acts as a source of geothermal energy. The screening criteria for the wells considered various parameters like flow rate, wellhead temperature, water cut, reservoir temperature, temperature gradient, permeability, porosity and secondary recovery mechanisms. The roadmap was used on a well and it yielded an output of 25 GWh of electric power from the co-produced hot fluids with an NPV of €431,000 to €957,000 over a period of 10 years.

A study done by Nagasree G., et al.[16] analyzed the use of geothermal energy in shallower, lower-temperature and naturally permeable regions that reduce drilling costs and induced seismicity. This proposition used the geothermal heat to supplement a secondary energy source. Hence, this hybrid approach may be used in various regions in the Switzerland and other regions in the world that could not have been used for geothermal electricity generation before. In this study, the net power output, the energy conversion efficiencies, and the economics of hybrid power plants were discussed. The authors also found out that a hybrid power plant outperforms two individual power plants which are a stand-alone geothermal power plant and a waste-heat power plants where moderate geothermal energy was available. These hybrid power plants proved to be more economical than the separate power plants in the study.

A study done by Gregoris P., et al[17], reviews the primary energy consumption of industries in Europe. These are responsible for almost 26% of the energy in Europe. Most of the energy sources that power the industrial sector are fossil fuel based. The authors find out that every industrial process possesses a multitude of waste heat streams at various temperatures that if recovered could contribute to the enhancement and the sustainability of the industries. To foster technological improvements and innovations, the efficiency of heat recovery equipment must be improved. This study goes through a systematic analysis where the waste heat and the Carnot's potential of every industrial sector and their temperature ranges were classified as Low Temperature (LT), Medium Temperature (MT) and High Temperature (HT). The 'big picture' of this study has shown that there is around 370 TWh of waste heat or 174 TWh of Carnot's potential energy per year unused in European industry.

To summarize, a considerable amount of energy in the industrial world is lost in the form of waste heat. Most of the authors found that extracting geothermal energy while utilizing existing oil and gas well infrastructure was economically viable. The papers that discussed wells in Italy[6] were in populous regions, wells in South UK basin[5] were used for agricultural purposes. Offshore wells have limited use for waste heat extraction as they are located far from populated areas and have other associated higher costs. The energy extracted from them could be converted into electricity and used to help power the platform operations. A combination of flow rate and bottom hole temperature must be considered when assessing feasibility. Sean M. Watson. et al.[5] proved in his study that even if a field has a higher bottom hole temperature, extraction of heat was not economically viable if the field produced too little fluid. The price of electricity is an important economic detail that determines the NPV of the wells. The average price per kWh of energy used in these studies was 0.20$ per kWh.

This thesis incorporates data from the Volve Field, a North Sea field in the Norwegian sector. Volve Field data were recently made public, making it ideal for study purposes. With some assumptions, the geothermal output from the major producing wells of the Volve Field is calculated and is assessed for feasibility. A separate study for the sustained injection of water into the reservoir to generate electricity was also considered in this research. Economic analysis similar to those performed in the papers discussed in this section was also performed for the Volve Field. This thesis concludes that there are many advantages to extracting geothermal energy from wells and it should be pursued whenever it is feasible and economical.

3. METHODOLOGY

The Rankine cycle is a process that is used in almost every power plant to generate electricity. In a Rankine cycle, there are four stages that work together to generate electricity. Figure 3.1 shows a simple scheme of a Rankine cycle. A source of energy is used to produce heat within a boiler which converts water into steam. This steam then travels to a turbine and expands through the blades of the turbine producing useful work. The steam then passes through a condenser where heat is rejected and is converted back into water. This water is then sent into a pump where it is pressurized and is sent into the boiler to be re-vaporized.

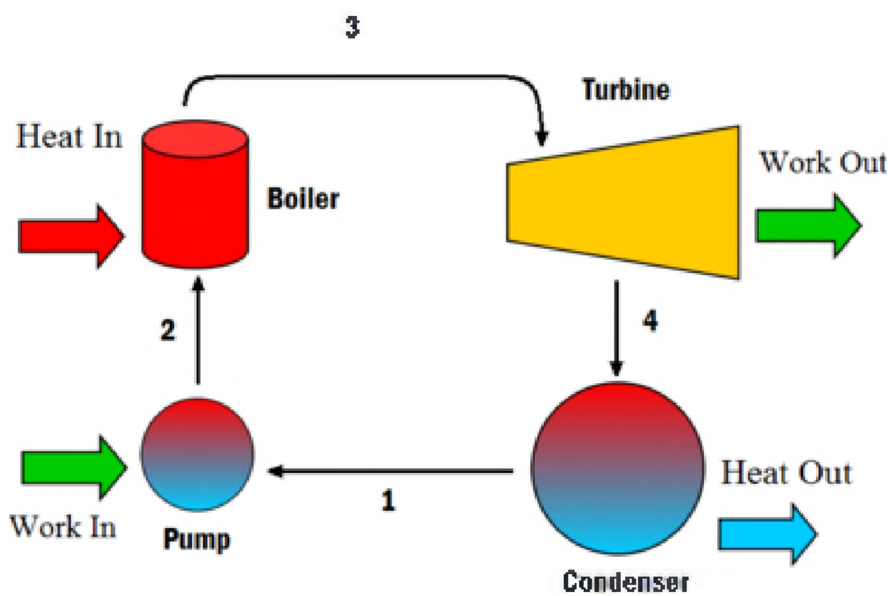

Figure 3.1: Simple scheme of a Rankine cycle (Credits - University of Calgary)

This technology is a thermodynamic process which converts heat into electricity if the turbine is connected to a generator. The majority of power plants in the world utilize this cycle to generate electricity. In coal power plants, coal is ignited to heat the water into steam while in nuclear power plants, the energy from the nuclear reactions heat the water around the control rods. The efficiency of the Rankine cycle is dependent on two factors, the temperature difference between the heat source and the heat sink and the latent heat of vaporization of the working fluid. The higher the temperature difference between the source and the sink, the greater the amount of energy which can be generated from the turbine.

The fluid must be cycled through the system constantly and must be vaporized and condensed constantly. Hence, a fluid with a high latent heat of vaporization is selected. Therefore, water is the most practical fluid for this cycle and hence it is used in many of the Rankine cycle installations. For optimal power generation efficiency for Rankine cycle systems which use water, the typical temperature range in use today is 180°C or higher. Unfortunately, for harnessing geothermal power from produced fluids or cycled (injected and produced) water, almost all reservoir and hence well head temperatures of virtually all wells in the world are far below 180°C. For this reason, an organic solvent such as butane or pentane or refrigerant is used in the Rankine cycle equipment, thus it is called an organic Rankine Cycle. These organic fluids are used because they can absorb heat, vaporize, power the turbine, condense and repeat the phase-change process at the lower temperature ranges at which geothermal wells operate.

The organic Rankine Cycle process for extracting geothermal energy from produced fluids involves two stages. Figure 3.2 shows a simple scheme of the organic

Rankine cycle. In the first stage, the produced fluid from the wells passes through a heat exchanger where it heats the organic solvent “secondary” fluid. This fluid vaporizes, flows through a turbine, then condenses (with the help of radiators), and then cycles back into the heat exchanger. A pump circulates the fluid in the system. The turbine turns a generator, generating electric power.

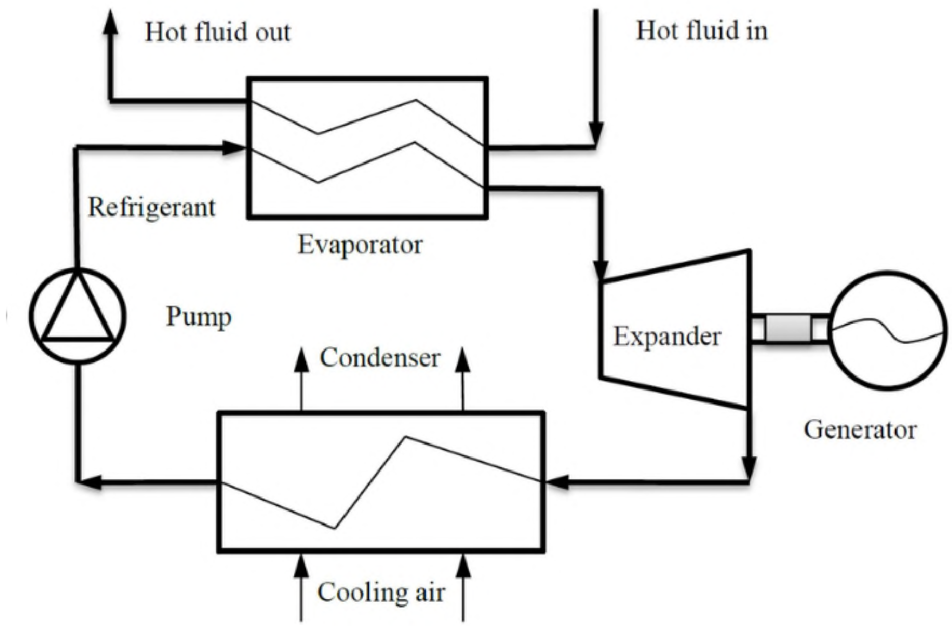

Figure 3.2: Simple scheme of an organic Rankine cycle (Courtesy: Jahedul I)

The Volve Field, like the vast majority of oil and gas fields, was developed for the primary purpose of producing oil and gas for all of the usual uses of oil and gas such as for fuels, lubricants, feedstock into synthetic polymer materials and many other uses. This thesis follows a recent trend of industrial professionals and researchers investigating whether oil and gas fields like the Volve Field also being used to harness geothermal energy. For an oil or gas field which is already economical, which already produces fluids at a profit, the prospect of capturing geothermal energy from the produced fluids and/or from cycling injected water using the same wells and producing equipment infrastructure to generate is certainly a bonus. Some may call it a "free lunch." Additional benefits of capturing and using this geothermal energy include less burning of fossil fuels, less CO_2 emission, reaching green energy targets, and other benefits to society.

This geothermal energy can be captured during two different periods of time from oil and gas fields—during the normal production phase (capturing the geothermal energy in the produced fluids) and after the field is largely depleted from cycling and producing injected water for the sole purpose of extracting thermal energy from the reservoir.
All oil and gas fields experience approximately exponential decline of their production over time, so there is an early period of relatively high production, a middle period of moderate but declining production, and a late period of barely economical production. During this normal producing life of the field and the wells, the geothermal energy contained in these produced fluids can be extracted.

After the normal economic life of the field as an oil and gas resource has ended, water can be injected into the field, pumped through the reservoir extracting the reservoir's heat energy, and produced. This cycling of water can be done for almost an indefinite period of time, taking advantage of the wells and field infrastructure, thus extending the economic life of the field as a geothermal resource.

In either case, the produced fluids exit the wells at a relatively high temperature, typically close to the reservoir temperature. The aim is to extract this heat from the fluids with the help of a heat-exchanger near the well head before the fluid enters the production facility. While producing just oil or gas, while hydrocarbon production is high, generally less thermal energy will be extracted, as the specific heat of oil is considerably less than that of water. But later in the life of the field, water production tends to go up as oil production declines (the percent water produced is called “water cut”). It is not uncommon for older wells to have 95 percent or higher water cut. For typical oil or gas production purposes, a high water cut is undesirable, but for geothermal purposes, the higher water content in the produced fluids generates more thermal energy due to the high heat capacity of water over oil.

In this section, we calculate the thermal energy flowing into the wells of the Volve Field per day from production data during the production period. For the sake of simplicity only the major producers of the Volve Field, F-12 and F-14 are considered for this study. These are wells with very comparable oil and water production rates in the earlier phases of production and as time progresses, the watercut of the produced fluid increases. For the evaluation of the thermal energy flowing into the well, the oil was also considered a medium for transporting heat into the well. Hence, the thermal output from each well, Q was calculated using the formula:

$$Q = c_{po}\rho_o q_o \Delta T + c_{pw}\rho_w q_w \Delta T \tag{1}$$

where

Q : Heat Flow into well per day (MW)

c_{po}: Volumetric Heat Capacity of Oil (J/kg°C)

ρ_o: Density of Oil (kg/m^3)

q_o: Volumetric flow rate of Oil (m^3/sec)

c_{pw}: Volumetric Heat Capacity of Water (J/kg°C)

ρ_w: Density of Water (kg/m^3)

q_w: Volumetric flow rate of Water (m^3/sec)

ΔT: Fluid temperature difference in and out of heat exchanger (°C)

With the help of available lab data, we were able to determine the **volumetric heat capacity** values and the fluid density. These are found in Table 3.1. With the help of the daily production rate schedule that was made public, we obtained the daily volumetric flow rates of both oil and water. With the intention of finding the geothermal potential, any heat losses that occur during the fluid transport and in the heat-exchanger are neglected. Owing to the higher reservoir temperature of the Volve reservoir, we have assigned the ΔT value for the following calculations a value of 40°C, assuming that the fluid exiting the heat-exchanger is at a temperature of 50°C. This value of ΔT is a conservative estimate, and it can be increased to 60°C with the help of better heat exchangers.

Table 3.1: Values of fluid properties

Property	**Value**
Oil Specific Heat Capacity (J/kgK)	2130
Water Specific Heat Capacity (J/kgK)	3930
Density of Oil (kg/m^3)	887.14
Density of Water (kg/m3)	1025

With the help of Equation (1) and above parameters, we calculated the thermal energy flowing into wells F-12 and F-14.

As can be observed from Figures 3.3 and 3.4, the thermal energy flowing into the well starts off low with major oil production but once the water cut of the wells starts to

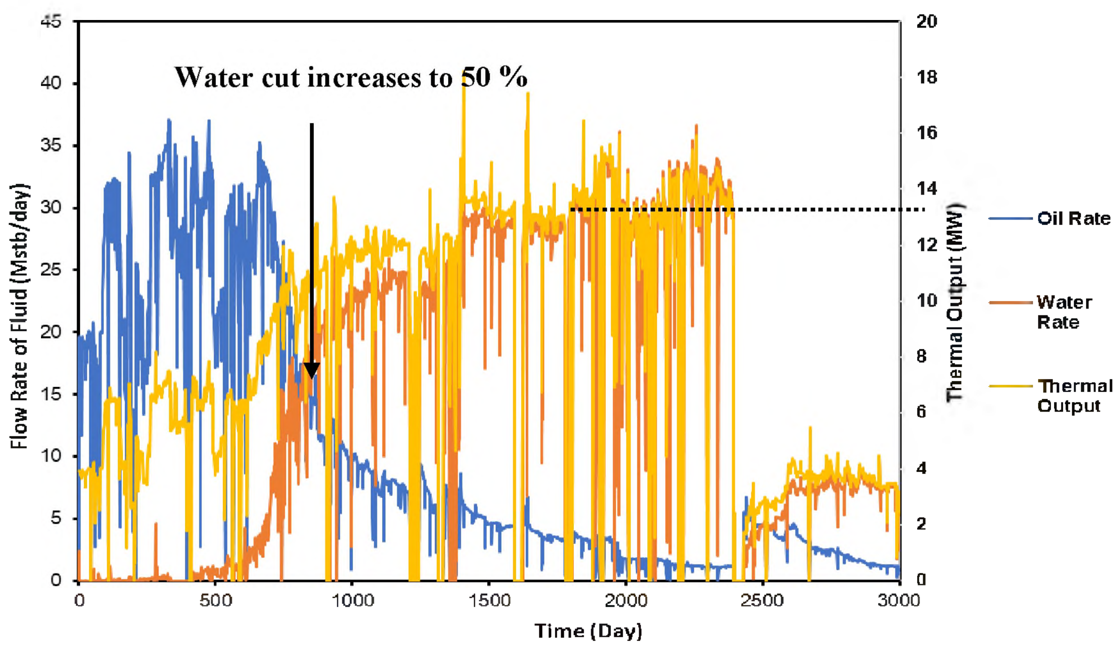

Figure 3.3: F-12 thermal output data

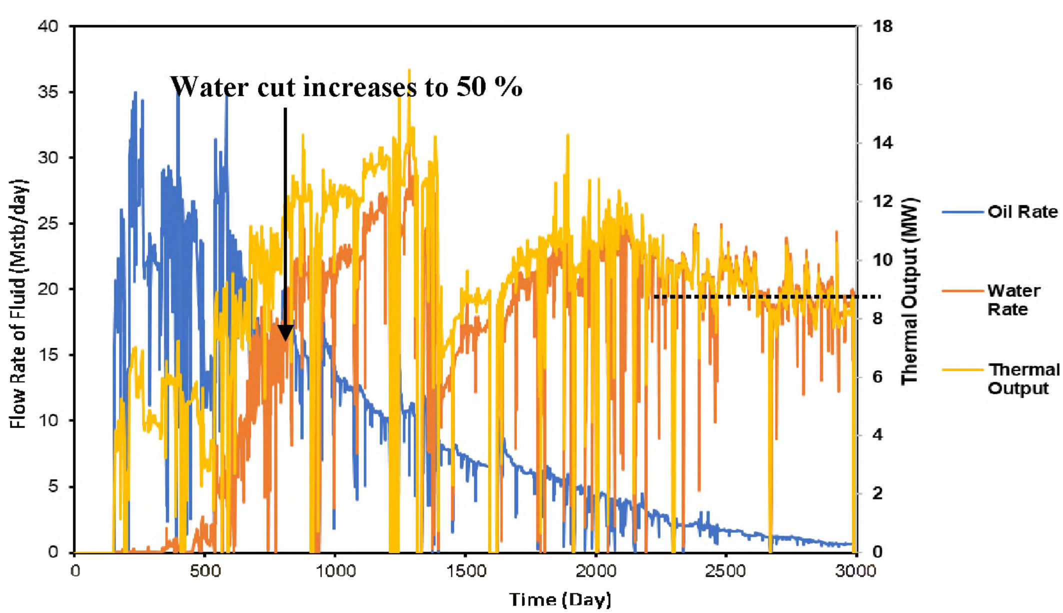

Figure 3.4: F-14 thermal output data

increase, the thermal energy output increases and averages out at around 13 MW per day in the late stages of production of F-12. In the case of F-14, it averages out to 9 MW of heat energy flowing into the well per day.

4. ABOUT THE VOLVE FIELD

The Volve Field is located in the North Sea, in the Norway sector, about 200 kilometers west of Stavenger. It is located five kilometers to the north of the Sleipner Øst field. The location of the field can be seen in Figure 4.1. The field was discovered in 1993 and the approval for the field development plan came in 2005 and the production started in 2008. The Volve Field was shut down after 8 years of production. The field produced twice the oil than what was expected.

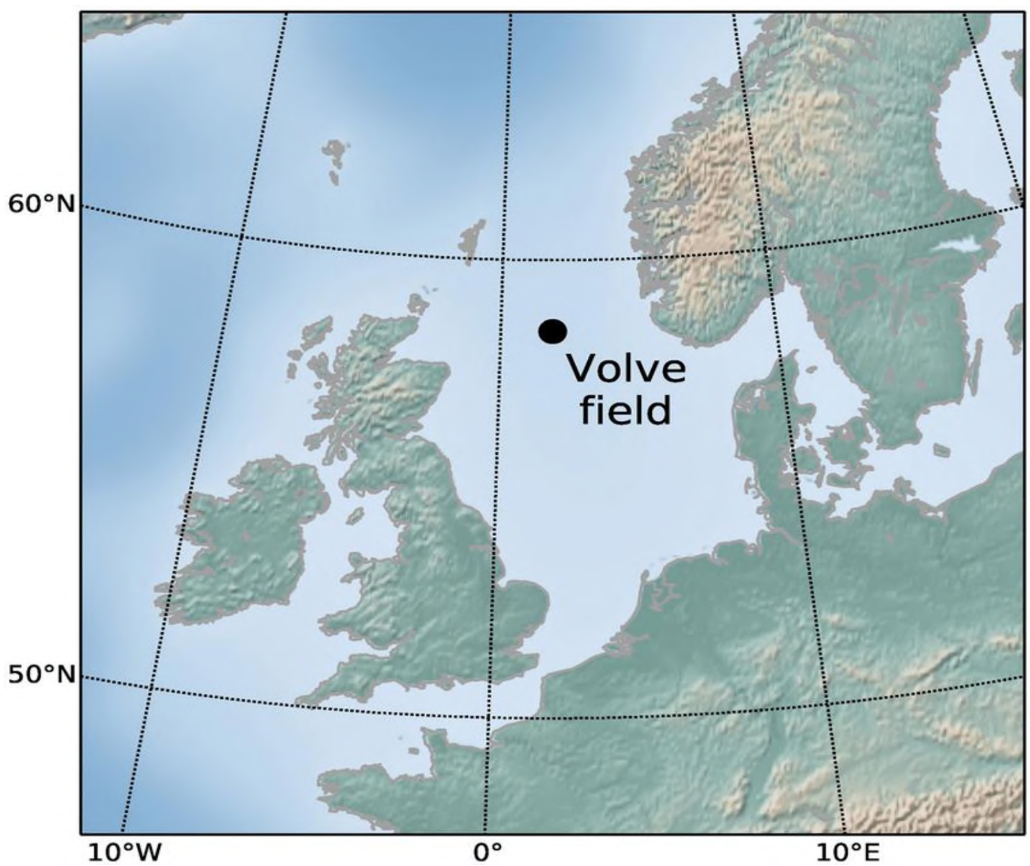

Figure 4.1: Location of the Volve Field

The Volve Field was reported as a fault block structure. The reservoir rock of the Volve Field is the Hugin sandstone formation of the Middle Jurassic age. The western part of the reservoir is heavily faulted and the communication across the faults is uncertain. Figure 4.2 shows the faulted reservoir of the Volve Field. The reservoir is clean and had low heterogeneity. The reservoir is at a depth of 2750-3100 meters below the sea level. The average porosity of the reservoir was around 21% and the average permeability was around 1 darcy. The reservoir had a net to gross ratio of 93%. The irreducible water saturation was an average of 20% and the oil-water contact was at a depth of 3120 metres below the sea level.

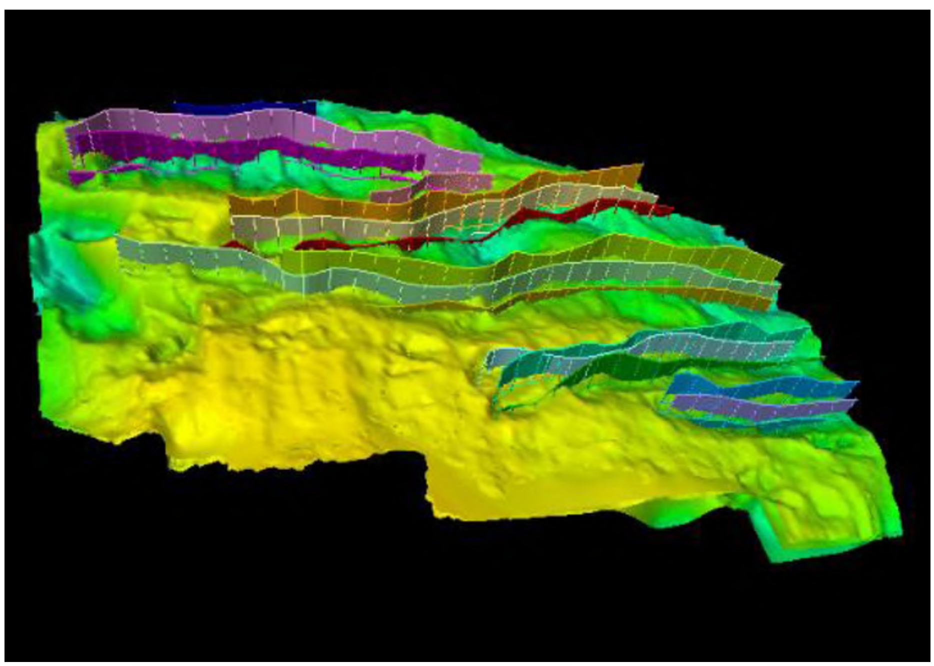

Figure 4.2: Heavily faulted reservoir of the Volve Field

Lab experiments indicate that the fluids were initially formed in the northwestern part of the field around 10 million years ago and later has migrated into the Volve reservoir.

With the help of a high gamma-ray response, Type-II Kerogen was discovered to be the source rock in the upper section of the Draupne formation. The oil in Volve Field was classified as under-saturated with an °API of 27-29 with a gas oil ratio of around 750 scf/stb. The stratigraphy of the Volve field can be seen in Figure 4.3.

The exploratory well 15/9-19 SR was drilled in 1993 and discovered the Volve Field. It encountered an oil bearing formation with a thickness of 18 metres. With the assistance of well testing, the hydrocarbon was characterized as a saturated 29° API oil. The initial oil production rate of this exploratory well was around 8550 bbl/day and the well had a productivity index of 62 bpd/psi which identified a potentially prolific reservoir. Subsequently, an appraisal well 15/9-19A was drilled and was able to successfully find a thicker reservoir of 88 meters.

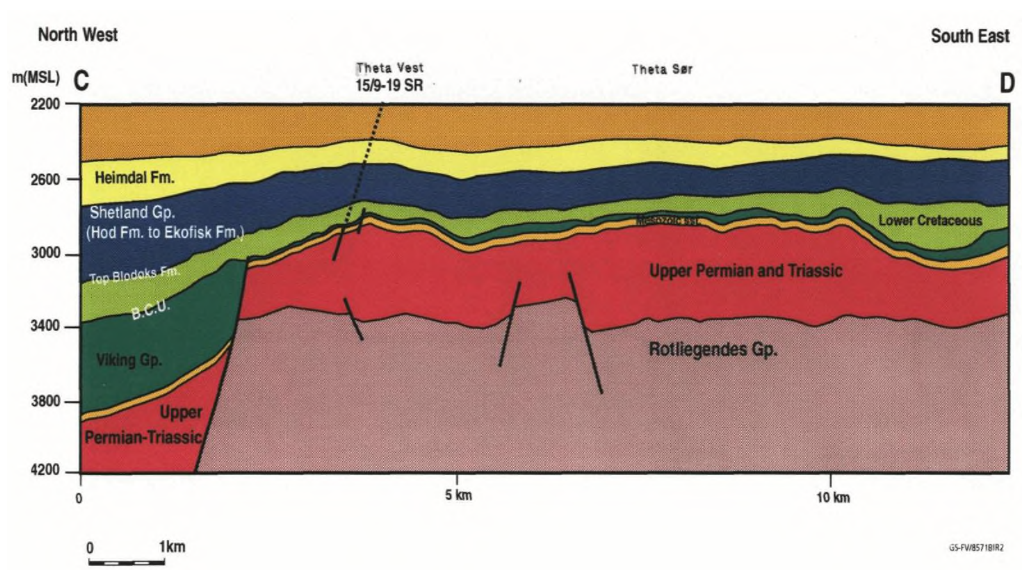

Figure 4.3: Stratigraphy of the Volve Field

The initial development strategy of the Volve Field was to drill three oil producers and three water injectors. The producers were to be completed with artificial gas lifting capabilities to further improve well production in the later stages. As the field was continuously updated and the existence of a prolific reservoir was seen, more wells were drilled into the field. A total of ten producers, three injectors and seven observation wells were drilled. At plateau, the Volve Field produced around 56,000 barrels per day and delivered a total of 63 million barrels of oil. Along with oil, the Volve Field produced around 88 million barrels of water and 53 billion cubic feet of gas. The well locations can be seen in Figure 4.4.

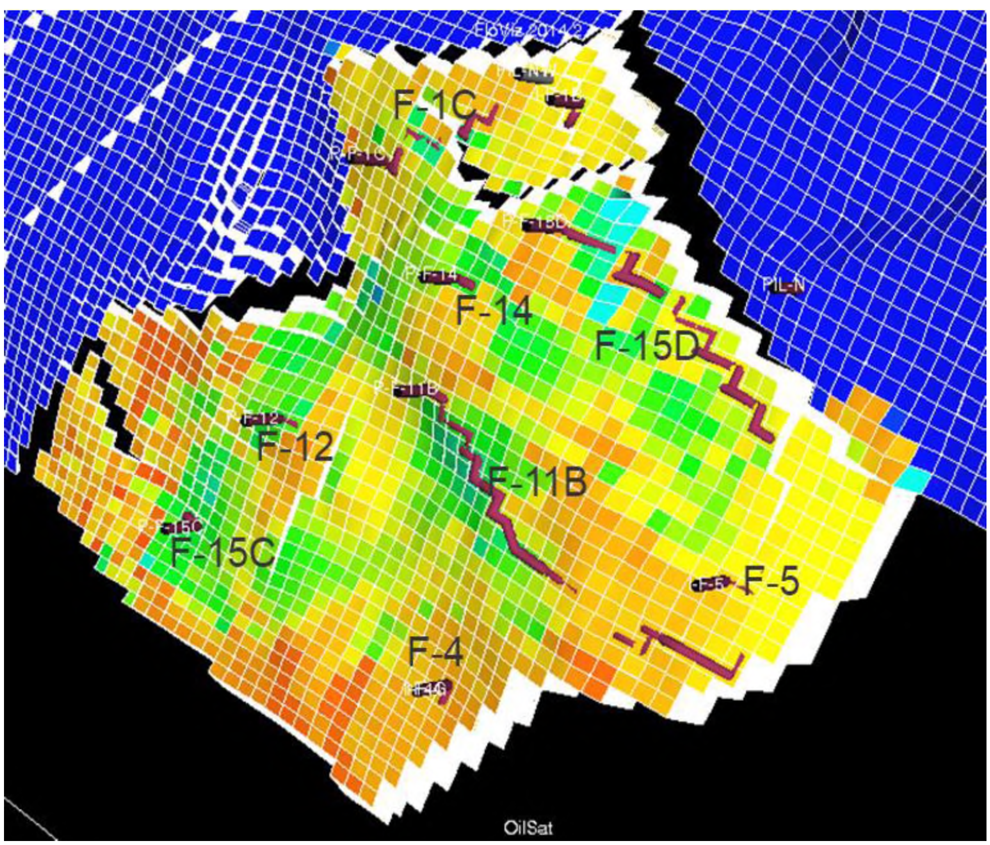

Figure 4.4: Well map of the Volve Field

The oil production of the Volve Field started in February 2008 after the first producer 15/9-F-12 was drilled. The major producers of the field were F-12 and F-14. In 2013, accounting to a decrease in the production below 13,000 barrels per day, three additional producers F-11, F-15 and F-1C were drilled. These wells helped increase the life of the field till 2016 after which the field was abandoned. The production data of the Volve Field was made public as of June 2018 to foster research. The yearly contribution of each producer well can be seen in Figure 4.5.

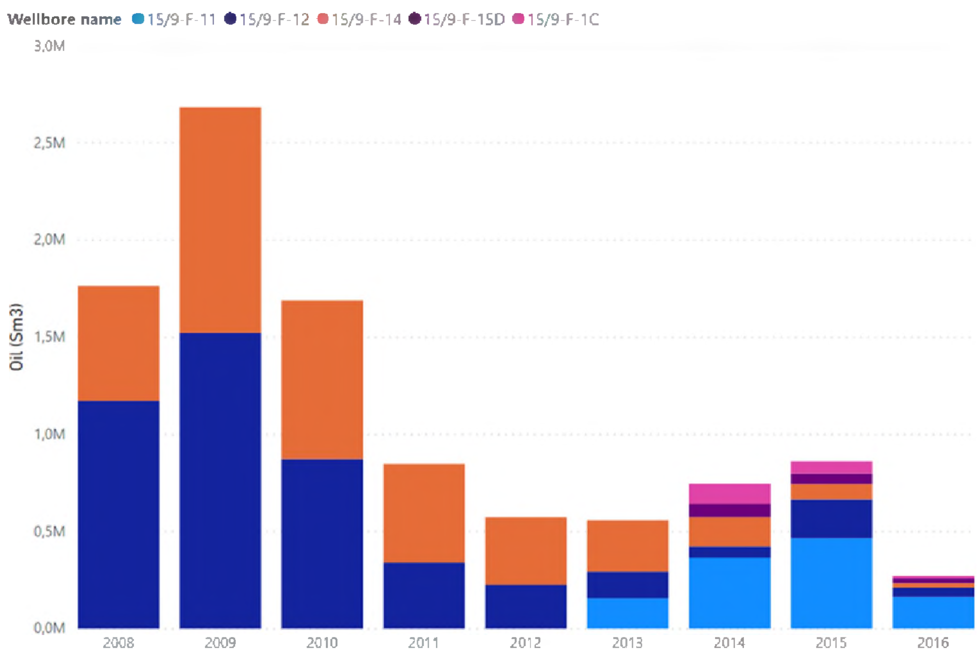

Figure 4.5: Yearly contribution of each producer[19]

The reservoir is located at a depth of 3100 meters with a temperature of around 106° C. This field is a reservoir with a high bottomhole temperature making it attractive as a source for geothermal energy. The aim of this thesis is to check the feasibility of the reservoir of the Volve Field as a source of geothermal energy.

5. ECONOMIC ANALYSIS

The Rankine cycle is used to convert the heat energy into electrical energy as discussed in the previous section. There is an efficiency linked to each type of Rankine cycle, which is directly proportional to the operating temperature ranges of the Rankine cycle. Higher operational temperatures yield higher efficiencies.

A typical wellhead is around 75° C which is classified as a low temperature use. The lower temperature requires the use of an organic fluid such as butane, pentane or a refrigerant which changes phases through the Rankine cycle stages over a lower temperature range that a water-steam system. Use of an organic fluid, unfortunately, lowers the efficiency of the Rankine cycle significantly. The efficiencies of different Rankine cycles are given in Table 5.1 where the major influencing factors are the fluid used and the temperature operating range.

Table 5.1: Efficiencies of different Rankine cycles

Rankine cycle type	Efficiency	Operating Range (°C)
Ideal (Theoretical maximum)	63.8%	∞ (Infinitely flexible)
Power Plants (Steam)	≈42%	500°C – 600°C
Organic cycle (Pentane)	≈10%	70°C – 90°C

The electric output of each well, E, is defined as the product of the thermal energy flowing into the well and the efficiency, γ, of the Rankine cycle used.

$$E = \gamma Q \tag{2}$$

where,

E: Electrical Power Output (MW)

γ: Efficiency of the Heat Exchanger

Q: Theoretical Heat Output (MW)

Considering an efficiency of 10% for an organic Rankine cycle, the electrical power output for the major producers of Volve Field, i.e F-12 and F-14 are calculated. The cumulative energy generated by these wells is given in below figures.

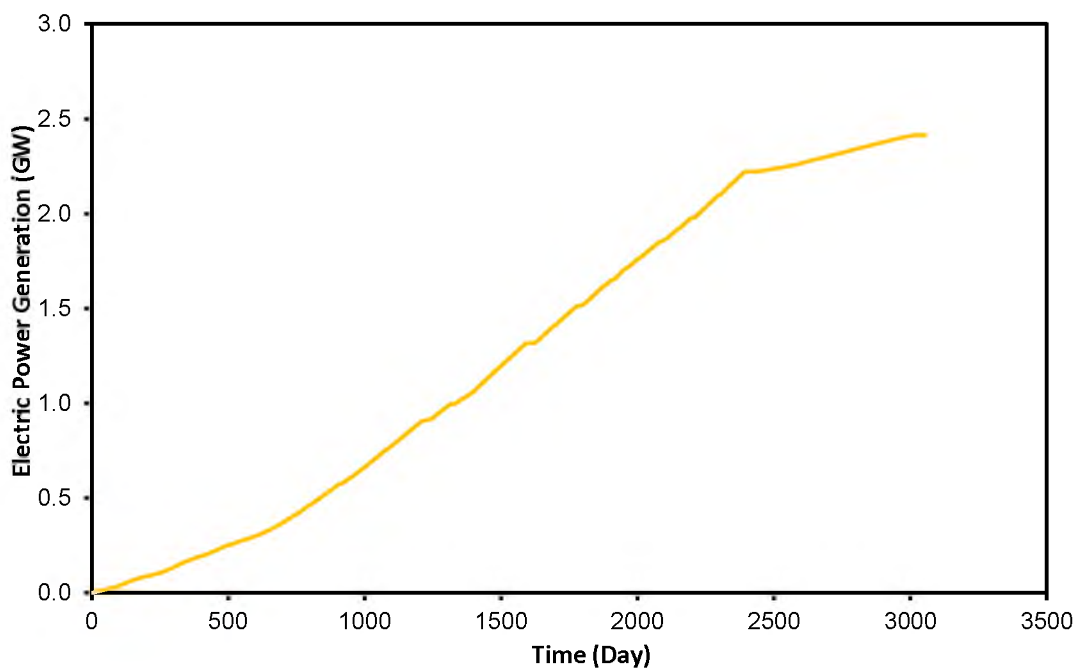

Figure 5.1: Cumulative electric power output from well F-12

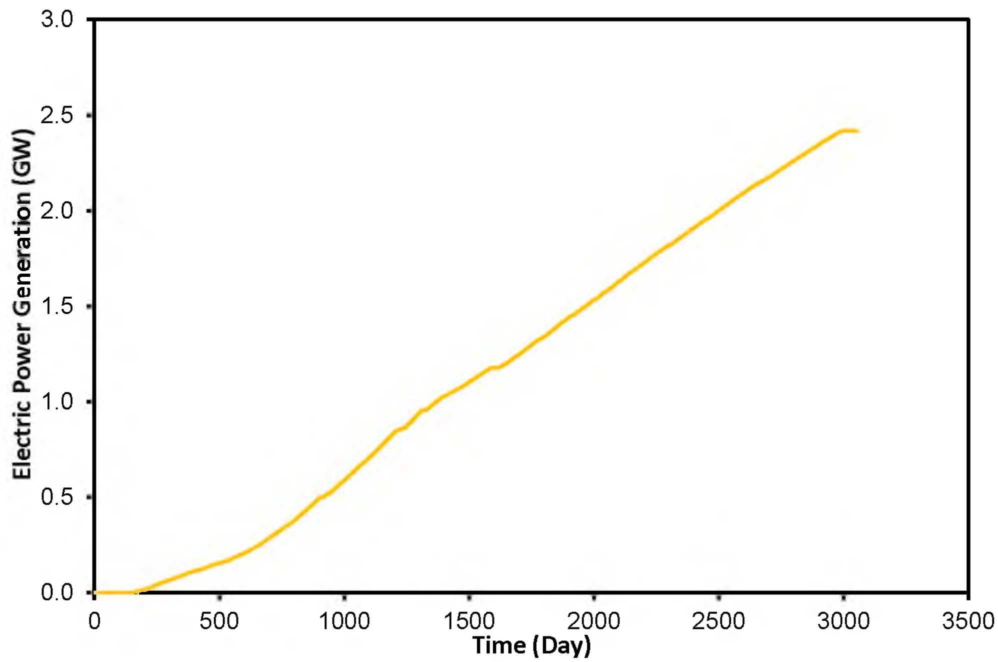

Figure 5.2: Cumulative electric power output from well F-14

As can be observed from Figures 5.1 and 5.2, each major producer, produces around 2.5 GW of electrical energy over the course of its lifetime. In addition to that, with the help of Rankine cycle technology, the transformation of the thermal output to electrical power output allows an economic analysis of the generated electricity to be carried out. The electric power output is converted to kWh, as electricity is bought in kWh, and the net present value or NPV of this generated electricity is calculated. The NPV is the sum of all the Present Values of the well's electricity.

The Present Value or PV is defined as:

$$PV = \frac{R_t}{(1+i)^t} \tag{3}$$

where,

PV: Present Value ($)

t: Time of cash flow (days)

R_t: Net Cash Flow at time, t ($)

i: Discount rate

The Net Cash Flow R_t, can be calculated as the difference between the Revenue and the Operational Expenditure of the system, the heat exchanger. With the help of the Net Cash Flow, one can see how much the well is generating electricity in terms of money per day.

$$R_t = R - O = pE - kE \quad (4)$$

where

R_t: Net Cash Flow, $

R: Revenue, $

O: OPEX, $

p: Price of electricity per KWH, $/kWh

k: OPEX per KWH of electricity, $/kWh

E: Electric Power Output, KWH

The parameters necessary for the evaluation of the NPV, i.e. p, k, i, are taken from the US Department of Energy[7,8] can be found in Table 5.2. The parameter, p is the price of the electricity and parameter, k is the operational expenditure involved in generation of electricity which includes the cost of maintaining the heat-exchangers. The parameter i, is the interest rate at which the money will lose its value over time. It is used to convert the future value to the current value.

Table 5.2: NPV calculation parameters

Parameter	**Value**
i	0.0026
p ($/kWh)	0.28
k ($/kWh)	0.03

We calculated the NPV for the two major producers in the Volve Field, viz, F-12, F-14 and an additional well F-15, and the results are shown in Table 5.3.

Table 5.3: NPV calculations for Volve Field major producers

Well Name	**NPV ($)**	**Cash flow per day ($/day)**
F-12	1,324,215	4,798
F-14	944,871	4,744
F-15	249,113	3,705

Each major producer was able to generate a NPV of around $1 million. F-15 is the third largest producer of the Volve Field that only produced fluids in the last two years of the field life and it generated an NPV of $250,000. Similar analyses have been conducted for all the producers in the Volve Field, and all the minor producers combined generated an NPV of $1 million.

6. THERMAL ENERGY IN PLACE ESTIMATION

6.1. SETUP

The energy output estimates in the previous sections quantify the potential thermal output of the major producers of the Volve Field. However, not all the geothermal energy flowing into the well is converted into electricity. Every energy conversion process has some inefficiency.

In the previous section, we calculated the electrical energy that could have been generated from the thermal energy carried to the wellhead by the production fluids of the Volve Field. However, the thermal energy carried by the produced fluids is only a part of the full thermal energy picture of the entire Volve Field reservoir. The majority of the heat energy lies within the mass of the formation and the main aim of this section is to estimate the total thermal energy present in the Volve Field rocks and fluids.

The core of the Earth is at a temperature of 5000°C. This core acts as a source of heat energy that flows radially outward from the core to the mantle and eventually to the surface of the earth. Any energy that is consumed from within is resupplied by the core. The convection currents in the Earth's surface can be seen in Figure 6.1. The core has a radius of 4,000 km and has a specific gravity of 12. This, when combined with the temperature of the core shows the existence of an immense amount of thermal energy contained within the earth, beneath its surface. With the help of specific heat capacities, the total energy in place in a given reservoir can be calculated.

Similar calculations have been made for the reservoir of the Volve Field. The area of the field, along with the producing interval are considered. The properties of the reservoir rock were determined by lab experiments and the total energy in place of the Volve Field was calculated.

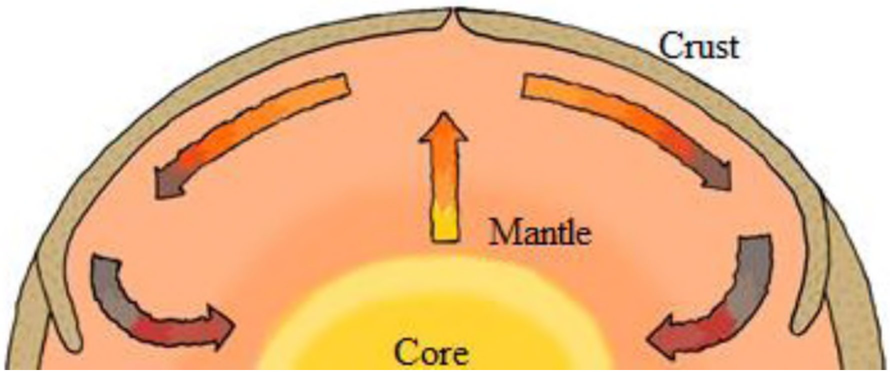

Figure 6.1: Convections currents in Earth's surface (Credit : Henry Reich)

6.2. CALCULATIONS

The energy in place for the Volve Field is calculated using the thermal energy equation.

$$Q = \rho c_p V \Delta T \qquad (5)$$

where

Q: Heat Energy present in the reservoir (MJ)

ρ: Density of rock (kg/km^3)

c_p: Volumetric Heat Capacity of the rock (J/kg°C)

V: Volume of the rock (km^3)

ΔT: Temperature difference (°C)

The Volve Field produces from the Hugin Formation. This formation is a sandstone formation and the rock properties for the sandstones can be found in Table 6.1. For finding the heat energy within the reservoir, the reservoir thickness and its areal extent are necessary to calculate the volume of the reservoir. From the logging data, seen in Figure 6.2 and the stratigraphy seen in Figure 6.3, that was made public, we obtained the production interval which was around 400 meters. And the considering the smaller size of the Volve Field, a conservative estimate of a total drainage area of 200 km^2 was assumed and the fluids were assumed to be produced at the reservoir temperature. Once the fluids exit the heat exchanger at the wellhead, they were assumed to have an ambient temperature of 40°C which yields a ΔT of 66°C. Using Equation (5), we calculated the total heat energy in place.

Table 6.1: Properties of Hugin Formation Sandstone

Property	**Value**
Density (kg/km^3)	2.33E+12
Heat Capacity (J/kg°C)	921.51

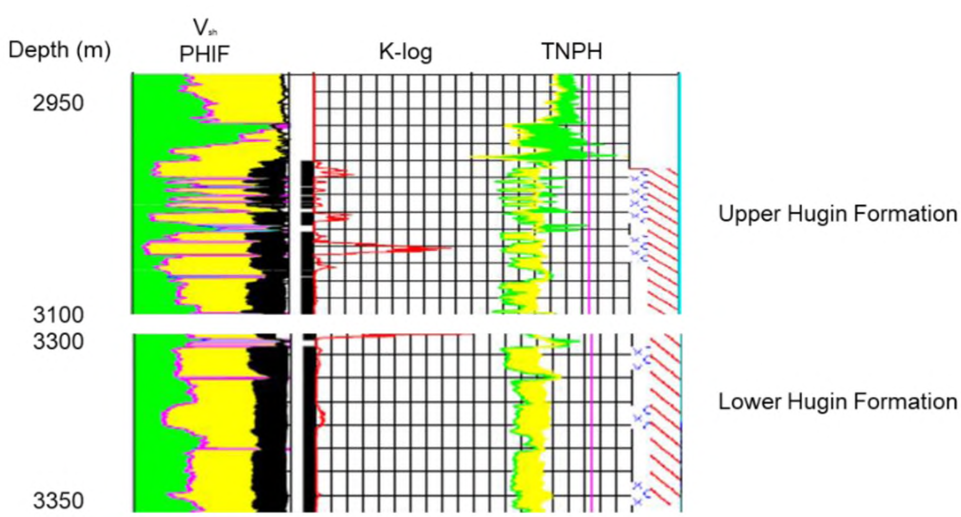

Figure 6.2: Well log of F-15

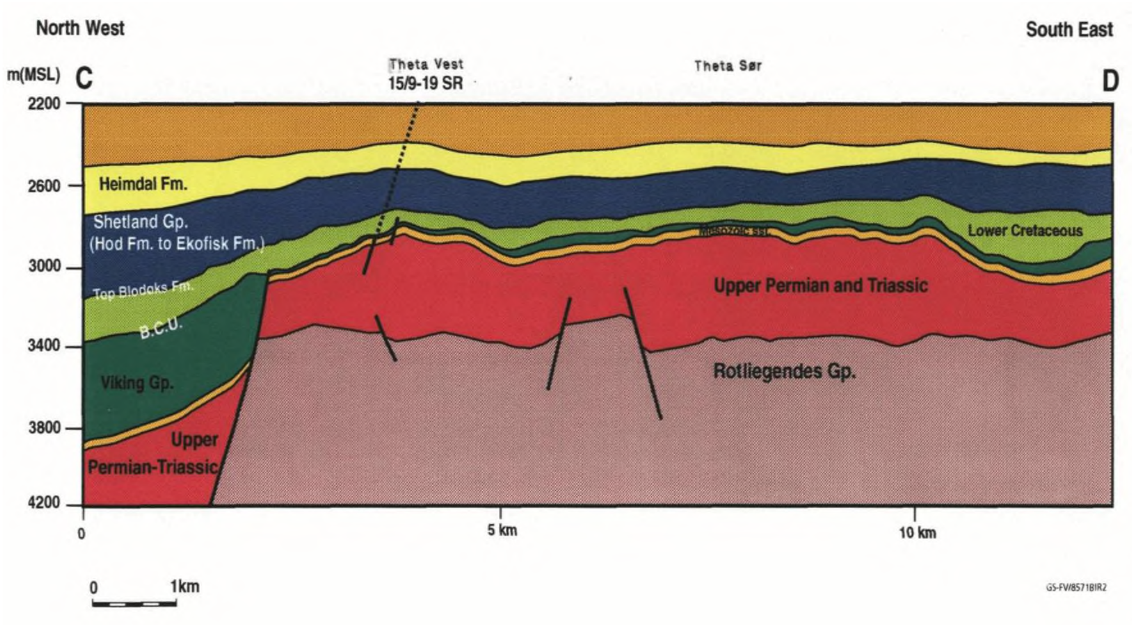

Figure 6.3: Cross-section of the Volve reservoir

Table 6.2: Total heat energy in place calculations

Temperature (°C)	**Area (km²)**	**Volume (km³)**	**ΔT (°C)**	**Q (J)**
106	200	80	66	1.12E+19

The thermal energy in place calculations can be found in Table 6.2. Similar calculations were made in a study done by Gasnold, et al.[1] where they calculated heat energy in place for different oil basins and fields. They used a recovery factor of 0.001 (one tenth of one percent!) for calculating recoverable heat energy from a given reservoir. The same recovery factor was used in this study for the calculation of energy in place for the Volve Field. This recovery factor was taken to simulate the situation in which not all the heat is recovered. There is always heat which cannot be recovered and taking a very conservative estimate of 0.001 will help reproduce operational results. This recoverable heat was then converted to kilowatt-hours and then the efficiency of the organic Rankine cycle, i.e. 10% was applied to it to convert the heat energy in place to potential electrical energy. This electrical energy can be used to power homes if it were to be distributed. The average electricity consumption of a household is 10.4 MWh per year. The number of households that can be powered with the aid of the energy in the Volve Field was then calculated. The results of these calculations are shown in Table 6.3.

However, it should be noted that these calculations consider all the heat in the Volve Field to be extracted. This is not the case since there is always heat that flows from the Earth's core into the reservoir making is a non-closed loop. If we are able to extract the geothermal energy economically, this heat could be extracted indefinitely.

Table 6.3: Estimated number of homes that can be powered

ΔT (°C)	**Q (J)**	**Recoverable Q (J)**	**MWh**	**Electric MWh**	**No. of Homes**
66	1.12E+19	1.12E+16	3.10E+06	3.10E+05	29,843

7. HARNESSING THERMAL ENERGY BY WATER INJECTION

7.1. SETUP

In Section 2, the thermal output energy for the major producing wells of the Volve Field was calculated. It is natural that during the years of production, the oil wells will generally produce less oil and produce more and more water (the percentage of water relative to oil production is called "water cut"). As fluids are produced, the reservoir pressure declines, the oil in the reservoir is depleted, injected water reaches the producing wells, the saturation of water in the reservoir increases, and thus the water cut in the produced fluids increases significantly. This can be seen in day 700 in Figure 7.1.

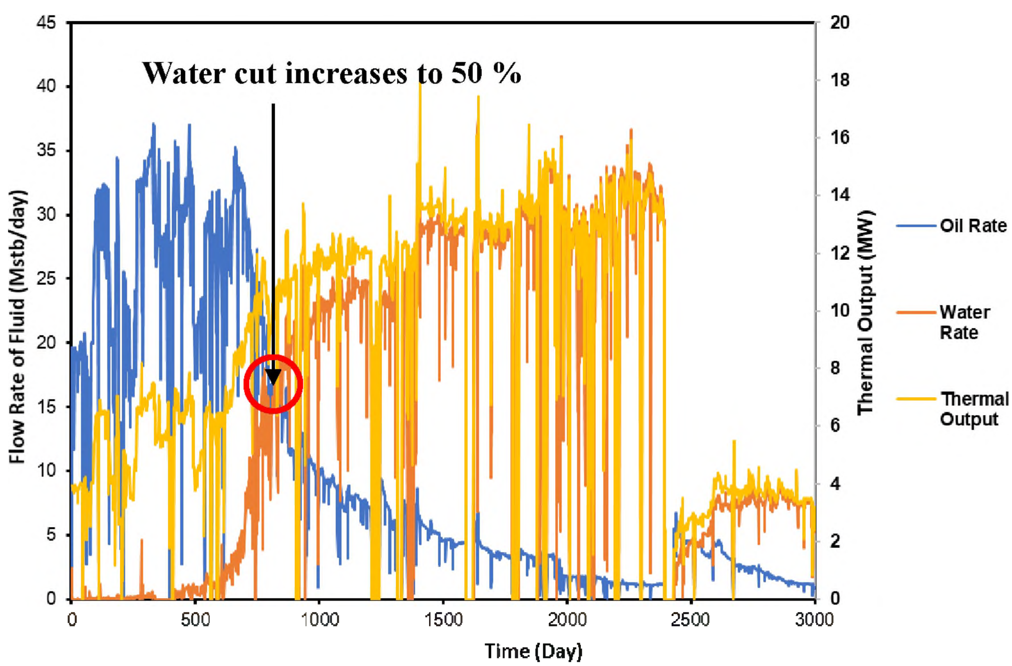

Figure 7.1: Day 700 : watercut increases to 50%

However, this decrease in the oil cut of the produced fluid does not decrease the thermal output energy, but in contrast, it increases the thermal energy flowing into the well. The reason for this is that the heat capacity of the water is much greater than that of oil. This ensures that more heat is being delivered into the well.

From the point of view of electricity generation, the increase in the saturation of water in the produced fluids of the well is beneficial. In this section, this idea is carried and tested out by taking it one step further and allowing the injectors to keep injecting water and the producers to keep producing the water that has been injected. This sets up an endless circulation or cycling of water through the reservoir, where the water is re-injected and re-produced. The water adsorbs heat from the mass of the reservoir, carries it to the surface, the water passes through the heat exchangers at the surface, is cooled to a baseline temperature, and the process is repeated as it is re-injected. The organic fluid in the Rankine Cycle system is heated in the heat exchangers, cycles through the system, and thus electricity is generated.

This sustained injection approach where water is cycled is a secondary stage which is applied after the normal producing life of the field. The first stage involved extracting the heat energy of the normally produced fluids from the reservoir, and then using this energy to generate electricity. A simple scheme of this technology is shown in Figure 7.2. This second stage, where water is cycled, has a number of advantages. First, it takes advantage of already established infrastructure in depleted, end-of-life and/or abandoned oil or gas fields to generate electricity with the help of sustained water injection. Second, the economic value of extracting the heat adds revenue to the project, helping to improve the economics of a typical oil or gas project. Third, this stage can go on almost indefinitely, as long as the equipment is operational.

The reason this water cycling stage can go on indefinitely is that the reservoir is not a closed thermodynamic system. In this thesis we have calculated the high heat content of these reservoirs, but as cool water passes through these and extracts heat from the reservoir mass, more heat flows into the reservoirs from their surroundings. If the rate of fluid injection and heat extraction approximately equals the rate at which heat flows into the reservoir from its surroundings, theoretically the process can go on indefinitely. In field applications, care should be given to varying the water rate and monitoring produced fluid temperature to achieve an optimal rate. Too high of water rate could possibly cool the reservoir, reducing the water temperature over time. This will erode the economics of the process and shorten its life.

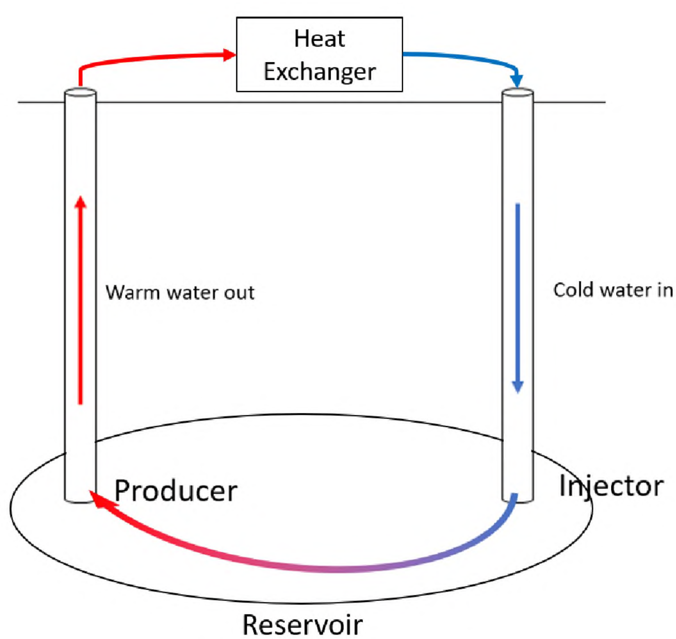

Figure 7.2: Sustained water injection loop

7.2. CALCULATIONS

The same equations that were used in Section 3 during the production period are used again here during the water cycling period. The same equations are applied for calculating the thermal output of the wells and for the same NPV calculations. A conservative estimate of 25,000 barrels of water per day was injected in each injection well and the same amount was considered to have been produced in the producers. The ΔT is assumed to be the same as the calculations in Section 2 as there are no changes in the reservoir. Since oil is not present in this case, Equation (1) reduces to:

$$Q = c_{pw}\rho_w q_w \Delta T \tag{6}$$

where

Q: Heat Flow into well per day (MW)

c_{pw}: Volumetric Heat Capacity of Water (J/kg°C)

ρ_w: Density of Water (kg/m^3)

q_w: Volumetric flow rate of Water (m^3/sec)

ΔT: Fluid temperature difference in and out of heat exchanger (°C)

The results of the economic calculations of the continued injection case can be found in Table 7.1.

Table 7.1: Results of the sustained injection case

NPV($)	**Cash flow per day ($/day)**	**Electric Output (KW)**
2,485,062	6,464	1,427

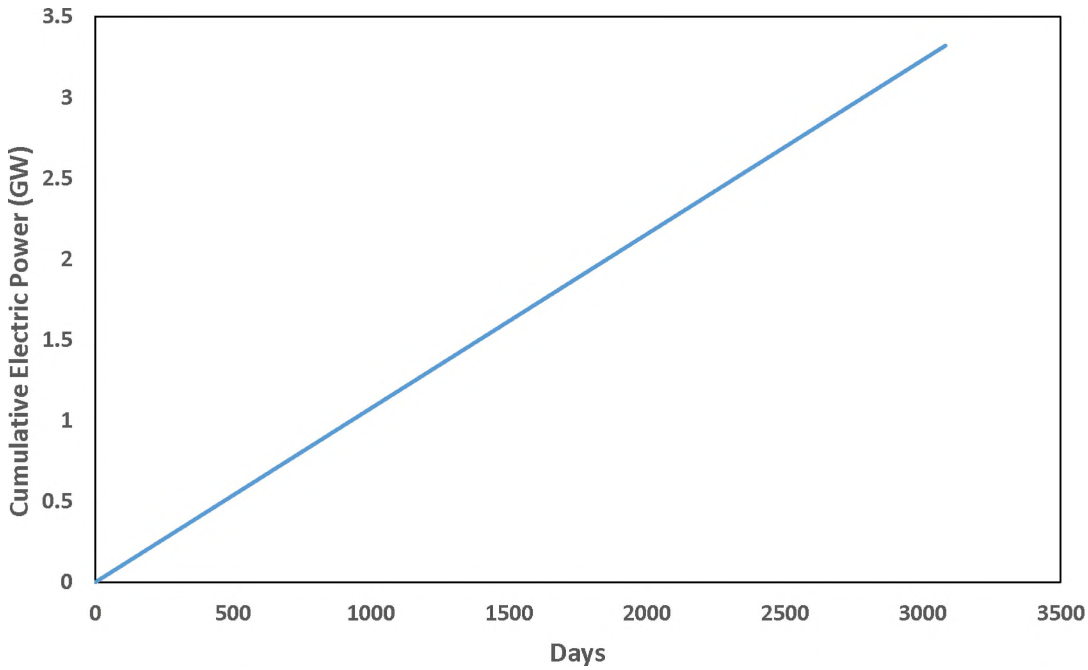

Figure 7.3: Cumulative electric power generated from each well

As can be observed from Table 7.1 and from Figure 7.3, each well is generating a net cash flow of around $6,500 per day and are generating a power output of 1.5 MW every day. This adds up to around 3.5 GW of power if the each well was installed with a heat exchanger. These numbers can be increased further if more water was injected. These calculations have considered a conservative estimate of 25,000 barrels of water being injected per day. According to the public production data, both injectors F-4 and F-5 were being injected an average of 35,000 barrels of water per day over their lifetime and exceeding 50,000 barrels of water per day in certain time frames. If need be, these injectors can inject more water to generate more energy from the reservoir.

As was noted earlier, in a real field application the rate of water injection should be studied to ensure that the temperature of the produced water does not begin to decline due to the injected water cooling the system faster than heat can flow into it from the reservoir's surroundings.

8. COMPARISON WITH OTHER FIELDS

The use of abandoned hydrocarbon wells for the generation of electric power from geothermal energy is not new. Considerable research has been done in this area, but yet the criteria for choosing a field for the generation of electrical energy has remained elusive. This is explained in detail in Section 2(Literature Review).

In this Section, we will compare the thermal and electrical output from the Volve Field to two fields (the Wareham Field and the Wytch Farm Field) featured in a study done by Watson et al.[5]. In that paper, they discussed the repurposing of wells for geothermal use, and they compared and contrasted different fields in the Southern UK basin. The location of these basins is shown in Figure 8.1.

Unlike the Volve Field, the Wareham and Wytch Farm Fields are still producing. So, with the help of decline curves, the future oil and water production were predicted, and the thermal output energy was calculated using Equation (5) since both these field have negligible oil production when compared to that of the water production which is the major contributor for the thermal output. The details for each field can be found in the Tables 8.1 and 8.2.

The Wytch Farm Field has a lower geothermal gradient and has a lower ΔT value. But this field makes up for this lower ΔT by having a very high production rate. On the other hand, the Wareham Field has a higher ΔT value, but the production rate is not high enough to justify the infrastructure cost in generating electricity.

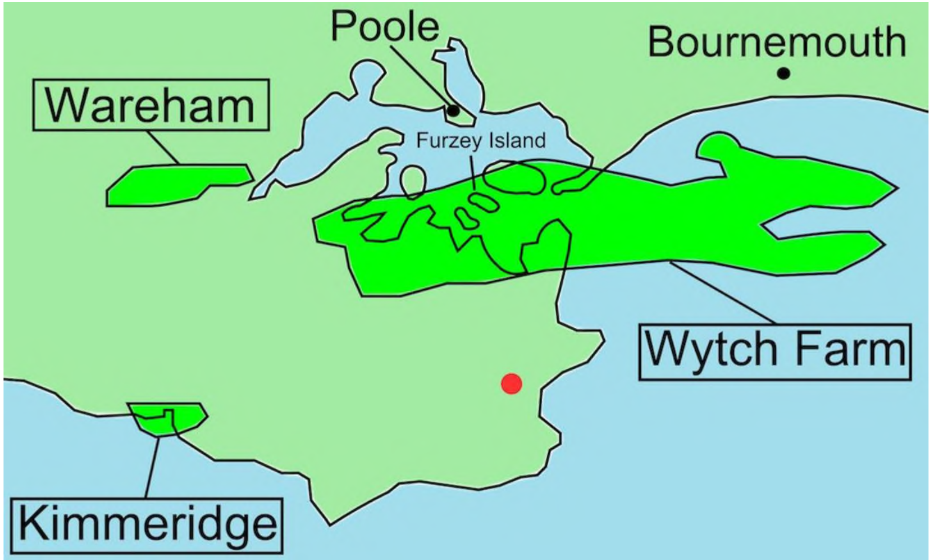

Figure 8.1: Location of Wytch Farm and Wareham Fields (Courtesy : GeoExPro)

Table 8.1: Wytch Farm Field thermal output energy information

Wytch Farm Production Rate (STB/day)	**ΔT (°C)**	**Density (kg/m³)**	**Capacity (J/kg°C)**	**Wytch Farm Heat Flow (KW)**
325,000	20	1,140	3,300	44,995

Table 8.2: Wareham Field thermal output energy information

Wareham Production Rate (STB/day)	**ΔT (°C)**	**Density (kg/m³)**	**Capacity (J/kg°C)**	**Wareham Field Heat Flow (KW)**
500	40	1,025	3,930	148

Based on the assumptions made in Sections 4 and 5, we can generate similar results for the Volve Field and compare the heat-flow output with those of the Wytch Farm and Wareham Fields. The calculations are shown in Table 8.3.

Table 8.3: Volve Field thermal output energy information

Volve Production Rate (STB/day)	ΔT (°C)	Density (kg/m^3)	Capacity (J/kg°C)	Volve Field Heat Flow (KW)
50,320	40	1,025	3,930	14,919

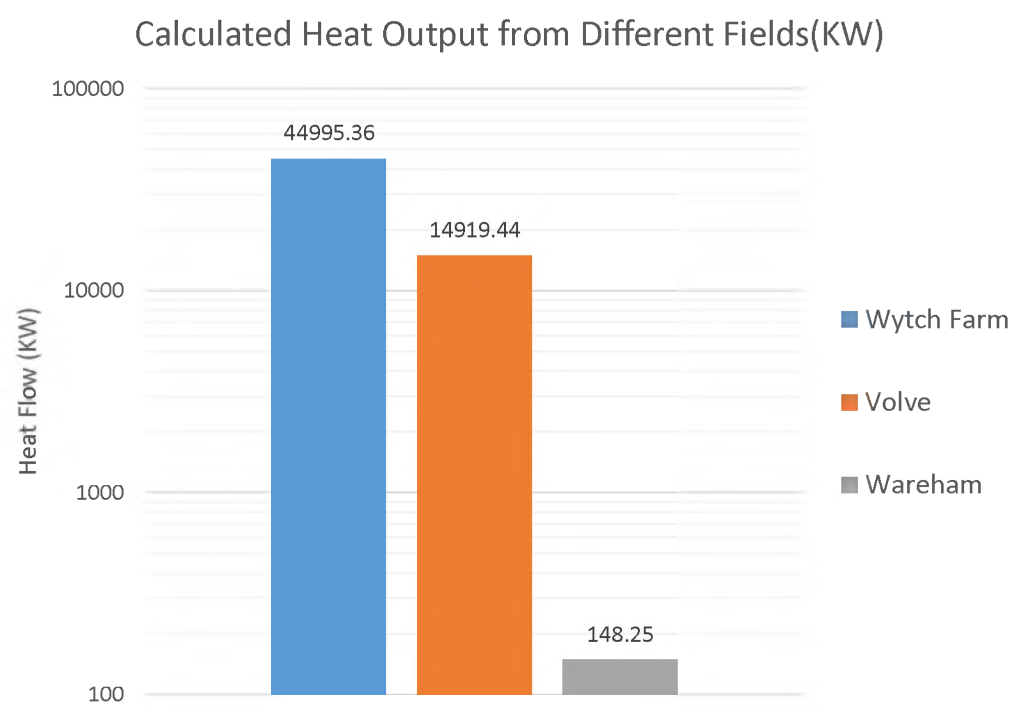

Figure 8.2: Comparison of heat output in different fields
(Please note that this is a log scale)

As can be observed from Figure 8.2, the Volve Field, being a considerably smaller field, has good potential for the generation of electricity from the thermal energy flowing into the well, similar to the results for the Wytch Farm Field. The Wareham Field, on the other had does not have enough heat flowing into the well for the generation of electricity to be economically feasible. The key takeaway from this discussion is that to be a good candidate for thermal energy, a field must have a sufficiently high reservoir temperature and a sufficiently high field flow rate capacity.

9. CONCLUSIONS AND FUTURE WORK

9.1. SUMMARY

In this work, the power generation from waste heat produced from oil production was investigated in detail. Much emphasis was given to the electrical energy that can be extracted from the co-produced fluid. The NPV analysis of the produced electrical energy quantifies the value proposition of the heat recovery.

The value proposition of the heat recovery in the Volve Field can be seen in Section 4 (Economic analysis). The electrical energy output of the each well is around 800 KW per day per well. If the infrastructure for the extraction of thermal energy was setup since the inception of production, over 7 GW of electrical energy could have been produced over the course of the 8 years of production. The energy that is being generated from the wells is comparable to green technologies that are being used as can be observed in Table 9.1.

Table 9.1: Comparison between different technologies

Technology	Power generation per day(MW)
Wind Turbine	1.5-3
Solar Farm	4
F-12 Well	0.7

The power generated by the well is “green” energy. There is little to no carbon footprint involved in the generation of this energy as the source of the energy is the reservoir and there are no emissions involved in this generation. This energy is also generated continuously and is not intermittent like that of solar energy or wind energy. It is not reliant on external factors such as climate. There is no issue with the storage of the energy as it is naturally stored within the reservoir and the cycling of the fluid into the reservoir removes the energy from the storage state. If less energy is required, less fluid is injected into the reservoir and vice versa.

The generation of electricity is not the only use of this geothermal energy. Various authors[5,6,11,10] have studied the use of abandoned oil and gas wells for extracting geothermal energy from the reservoir and utilize the heat in various direct applications like the heating of commercial and residential swimming pools, utilizing the heat as a source for warming of the greenhouses in different locations for growth of vegetables, using the heat for maintaining aquacultures for the cultivation of shrimp farms, etc.

With the help of the NPV calculations, we were able to evaluate the economic feasibility of the generation of electricity in the Volve Field. Both the major producers of the Volve Field were able to generate over 1 million dollars of NPV each. All the other wells combined, were able to generate another 1 million dollars of NPV.

If the produced water is injected back into the reservoir with the help of injector wells, this water is re-produced with a higher temperature and since water has a higher specific heat, it brings more heat into the wellbore. With an assumption of 25,000 barrels of water injected per day, the NPV generated by just the water production is 2.5 million dollars over the span of 8 years.

In Section 5, the total heat energy in place for the Volve Field is estimated and was calculated to be around 3100 GW of thermal energy. Water can be injected to help extract this thermal energy to power more than 29,000 average households.

A study done by the US Department of Energy [7,8] has determined that there is around 20 to 30 billion barrels of water produced per year in the oil and gas production operations. Of these 25 billion barrels, around 4 billion barrels have a fluid temperature greater than 80° C. These fields are good candidates for the generation of electricity from thermal energy. The power, if generated can be fed into a nearby grid system, thereby bypassing the need for the subsea cables, diesel generators, or proximity of the oil fields to an industrial site.

9.2. FUTURE WORK

In this work, all the calculations regarding the thermal output of the wells are theoretical. With the help of a reservoir simulation software, we can further improve the accuracy of the calculations with the help of a model. We can then vary different parameters to perform sensitivity analysis that improves the electrical energy output from each of the wells. A threshold temperature and flow rate for wells can be determined with the reservoir simulation models which can help identify various field that have the potential to be a source for geothermal energy. Oil and gas companies should compute the cost benefit analysis when producing from high temperature reservoirs while considering water injection.

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VITA

Bhamidipati Subrahmanya Chandra received his bachelor’s degree in Petroleum Engineering from Pandit Deendayal Petroleum University, Gandhinagar, India, May 2019. He received his Master of Science degree in Petroleum Engineering from Missouri University of Science and Technology in May 2021.

His research interests included reservoir engineering, well testing, artificial lift systems, enhanced oil recovery.