POLITECNICO DI TORINO

Department of Environment, Land and Infrastructure Engineering

Master of Science in Petroleum Engineering

Exploitation of the Geothermal Energy in Petroleum Wells to Improve the Economy of Mature Wells and Increase Their Lifetime

Supervisors:

Prof. Dario VIBERTI
Prof. Stefano LO RUSSO
Mrs. Glenda TADDIA

Lucien MERHEJ

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DECLARATION

I am submitting this thesis to be reviewed by the Politecnico di Torino in my pursuit of a M.Sc. in Petroleum Engineering at the aforementioned university. I hereby declare that this thesis is the outcome of my personal work and research. Any previous publications that I have consulted for information has been duly acknowledged in the bibliography.

DEDICATION

This thesis is dedicated first and foremost to my parents.
Without their constant presence and support I would not be standing where I am today.

ACKNOWLEDGEMENT

I would like to express my utmost gratitude to my supervisors; Prof. Dario Viberti, Prof. Stefano Lo Russo, and Mrs. Glenda Taddia, for their support and supervision throughout my research. They are the guiding hand behind my work, without whom this thesis would've never been possible.

I would like to thank all of my professors at the Politecnico di Torino as well. They made my stay at the institution fruitful and worthwhile.

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And last but not least, I am grateful for the new friends of different academic and cultural backgrounds that I got to meet in Turin, they made my stay in Italy an unforgettable and enriching experience!

ABSTRACT

The idea of using active oil wells or repurposing abandoned ones to generate electricity from geothermal energy has been documented since the late 80s. However, little has been done to compile the various studies done in this area.

This thesis provides insight into academic and governmental studies done on the subject. Pilot tests and existing in-field implementations were also considered. Co-production from active hydrocarbon wells and the repurposing of abandoned wells to purely geothermal ones are very different in application, therefore each situation was discussed in a separate chapter to give a specific dissertation for each case.

Existing studies have shown both concepts to be technically feasible. For co-production, the most important factors for a successful implementation were the wellhead temperature, the fluid flow rate, and the water cut. For abandoned wells the most crucial parameter was the well's bottomhole temperature. The power that hydrocarbon fields were able to generate ranged from a few hundred kW to a few MW of electricity. Furthermore, economic feasibility was also established. Profit can be made either by selling the produced electricity, or by using it on-site to lower the need of purchasing electricity from the grid. An NPV over $10million is possible for well executed projects.

In conclusion, co-production of oil and energy looks financially attractive, especially for small companies operating marginal wells with modest income. The repurposing of abandoned wells is also promising, mainly if the wells are in vicinity to the end users.

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NOMENCLATURE

Symbols and Units	
°	Degrees
$	US Dollars
£	British Pounds
%	Percentage
η	Efficiency
bwpd	Barrels of Water Per Day
C	Celsius
F	Fahrenheit
ft	Feet
gpm	Galons Per Minute
km	Kilometer
kg	Kilogram
m	Meter
mD	Millidarcy
q	Heat
Q	Power
s	Second
t	Tonne
T	Temperature
T_H	High Temperature
T_L	Low Temperature
T-s Diagram	Temperature vs Specific Entropy Diagram
w	Work
W	Watt
mW	**Milliwatt**
kW	**Kilowatt**
MW	**Megawatt**
TW	**Terawatt**
W_e	Watt Electric
kW_e	**Kilowatt Electric**
Wh	Watt Hour
kWh	**Kilowatt Hour**
MWh	**Megawatt Hour**
GWh	**Gigawatt Hour**

Abbreviations	
API	American Petroleum Institute
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CFCs	Chlorofluorocarbons
CHP	Combined Heat and Power
DOE	Department Of Energy (U.S.A.)
DOGGR	Division of Oil, Gas, & Geothermal Resources
DPGS	Direct Power Generation System
ESP	Electrical Submersible Pump
FPGS	Flash Power Generation System
GDP	Gross Domestic Product
HCFCs	Hydro-chlorofluorocarbons
HFCs	Hydrofluorocarbons
HHV	Higher Heating Value
NPV	Net Present Value
O&M	Operation and Maintenance
OPEX	Operating Expenditure
ORC	Organic Rankine Cycle
PFCs	Perfluorocarbons
R123	2,2-Dicloro-1,1,1-trifluoroetano
R134a	1,1,1,2-tetrafluoroethane
R152a	1,1-Difluoroethane
TIP	Turbine Inlet Pressure
TOP	Turbine Outlet Pressure

CHAPTER 1: INTRODUCTION

1.1 Co-production

In this thesis we will refer with “co-production” to the simultaneous production of hydrocarbons and geothermal energy from a single oil well or oil field. With this technology, the heat contained in co-produced geothermal fluids of Oil and Gas operations, usually brines, is used to produce electricity and/or heat.

The aim of geothermal co-production is the extension of the economic life of a field by lowering its energy costs, and/or making a profit by selling excess energy production back to the grid. Consequently, postponing the date of the field’s abandonment will also increase the final oil/gas recovered and hence increase profits from oilgas sales.

Co-production also has environment benefits. By using electricity generated from geothermal energy, the usage of conventional electricity produced from burning fuel is reduced. Burning less fuel means a lower emission of greenhouse gases associated with a well’s operation.

1.2 Well Conversion

In this thesis we will refer with “well conversion” to the transformation of an oil producing well into a geothermal well. Usually when a well becomes unprofitable it is abandoned. If an abandoned well has a bottomhole temperatures high enough to sustain geothermal exploitation, and if the reservoir properties are favorable, it can be converted into a geothermal well.

The aim of this is purely the production of geothermal energy. Plugging the well is no longer needed so the oil producer will save decommissioning costs, and additionally make a profit by selling the well along with the relevant data to the geothermal operator. The geothermal operator will save as well, mostly when it comes to exploration and drilling. These benefits are discussed in more detail in the upcoming chapter.

1.3 The Potential for Cooperation

The heat flow between the Earth's interior and its surface is equal to 47 TW. This heat reaches the Earth's surface at a temperature too low to be useful for energy production **(Davies et Davies, 2010)**. Any exploitation of this energy has to occur deep inside the Earth's crust which comes at a high cost of exploration and drilling. Luckily, petroleum companies already possess extensive exploration data with a myriad of already drilled wells all over the world.

The modern advancements in technology made it possible to exploit wells with bottomhole temperatures as low as 74 °C **(Holdmann, 2007)**. Hydrocarbon wells can reach this temperature and often even exceed it. In Texas alone, over 17,000 wells with bottomhole temperatures above 100 °C have been studied **(Airhart, 2011)**. This implies that producing electricity from abandoned wells is technically feasible. We should however keep in mind that not every well will prove economically viable for exploitation.

Room for cooperation and cost mitigation exists between the geothermal and Oil and Gas industries. For producing wells, it could mean an economic life extension. For depleted wells, Oil and Gas companies could save millions in well abandonment costs, and score a profit by selling off their depleted wells to willing buyers. Companies looking for geothermal energy can save the upfront costs of drilling and exploration, as well as the basic infrastructure that would already be in place.

1.4 Thesis Objectives

This thesis will discuss the latest advancements in combining oil and geothermal production. We will discuss how to co-produce geothermal energy in active and maturing hydrocarbon fields, as well as the conversion of depleted fields into geothermal ones. Both cases have different economic benefits for the oil producer and the geothermal producer. And both cases request different approaches to be used with optimal economic result.

The technology in question will be the ORC (Organic Rankine Cycle). The thesis will showcase the pros and cons of its different configurations, and look at suggested and already existing projects to determine whether or not the subject is worthy of more research.

1.5 Thesis Layout

Following the introduction, the 2nd chapter will discuss the economic benefits of co-production and well conversion will be discussed.

The 3rd chapter will be an introduction to geothermal energy and most importantly to the ORC (Organic Rankine Cycle), which is the prevalent model for producing energy from low temperature wells.

The 4th chapter discusses previous implementations and case studies for co-producing in active wells. The 5th chapter will treat the same subject but for abandoned wells. The 6th chapter discusses a few miscellaneous cases that are none the less relevant to this thesis without fully falling under the previous two categories.

The 7th chapter will be the conclusion.

CHAPTER 2: ECONOMIC BENEFITS

2.1 The Changing Rules in an Aging Industry

The drilling of the Drake Well in 1859 in Titusville, PA is largely considered to have marked the beginning of the commercial oil industry. Ever since, the importance of hydrocarbons has increased until it became the major international energy source. As of 2015, Oil and Gas account for a combined 56.7 % (Oil: 32.9 %; Gas: 23.8 %) of global energy consumption **(BP, 2016)**.

As more and more wells are produced and eventually depleted, we are faced with an ever increasing number of abandoned wells. Add to this the abandoned exploration wells that were left after their fields were deemed unprofitable. With these abandoned wells comes the problem of pollution due to leaks, and the added financial burden of decommissioning and pollution remediation.

In addition to abandoned wells, existing wells are maturing. And where water is present, the issue of an increasing water cut usually comes with it. The water cut represents "the ratio of water produced compared to the volume of total liquids produced" **(Schlumberger Glossary)**. Water cuts exceeding the 90 % mark are not unusual in oil fields. In some of the more extreme cases water cuts of up to 99 % have been encountered **(Falcone et al., 2017)**. An increasing percentage of water production increases the required OPEX for water treatment and disposal, and simultaneously decreases the income due to lower oil production rates. This renders the profits of producing wells ever more marginal until a well is no longer economical and has to be decommissioned.

Meanwhile, due to a relative instability of the oil price in recent years, along with a worldwide push to stricter climate change regulations, many of the industry's top players started diversifying their operations into renewable "green" energy sources. In 2016, Shell formed its "New Energies" division with a desire to spend 200 million $ yearly on low carbon resources **(The Guardian, May 15th, 2016)**. Later in 2017, they announced their plan to increase this annual budget to 1 billion $ by 2020 **(Bloomberg, July 7th, 2011)**. French company Total has long been on the forefront of big oil companies going green, with two of its most notable investments being valued north of 1 billion $ each. In 2011, the company acquired 60 % of US based solar panel manufacturer SunPower for 1.38 billion $, and in 2016 bought the French battery maker Saft for 1.1 billion $ **(Bloomberg, April 29th, 2011) (Reuters, May 9th, 2016)**. Meanwhile Statoil is using its offshore oil expertise to branch out into offshore windfarms with four projects in the UK, one in Germany, and one in the US. Their most ambitious project was a first of its kind floating windfarm off the Scottish coast **(Statoil)**.

This shift of paradigm isn't exclusive to the private sector either. Oil rich Middle Eastern countries have recently sought to diversify away from oil. Saudi Arabia is looking to sell part of its oil assets and reinvest them elsewhere, while the UAE succeeded in decreasing the oil share of its GDP down to 30 % in 2017 (**The Guardian, April 1st, 2016) (CIA, 2018)**.

When even the biggest profit makers in the industry are seeking to invest in alternative resources, it becomes clear that a new approach is essential to survive in the coming decades. So what incentives exactly can the geothermal sector offer the oil sector? And can the geothermal sector in turn benefit from cooperating with the oil industry?

2.2 <u>Benefits for Oil Companies</u>

Benefits for oil companies exist for producing wells, for abandoned wells, and for wells that have failed to show economic viability during the exploration stage.

For producing wells, the co-production model uses the thermal energy of produced water. This thermal energy would otherwise be lost to the environment. As the water cut increases at a well, the oil cut simultaneously decreases. As time goes on, a lower profit will be won through oil production, while more thermal energy will be available to be exploited. So while a lower cut lowers profit, the higher geothermal energy production could cover a higher fraction of the well's electrical needs, keeping energy expenditures low. Lower energy expenditure implies that the project will stay profitable for longer. And a longer production lifetime brings with it a higher cumulative oil production. In some cases, the energy production could completely cover a well's energy needs, and even exceed them. In this scenario some of the produced electricity could be sold back to the grid at an additional profit **(Fershee, 2009)**.

For abandoned wells, oil companies have the opportunity of selling their wells to companies specialized in geothermal energy production along with all of the relevant reservoir data collected over the years. By doing this, valuable time and money can be saved on well plugging and abandonment, while securing an additional income by selling the well and data.

For wells that have failed to show economic viability during exploration, the company would have gathered a large amount of geophysical reservoir data such as permeability, as well as knowing the well's bottomhole pressure and temperature. This data will determine whether re-purposing of the wells for geothermal energy production is possible or not. If the data is favorable, the "failed" oil well can be sold (at a profit) and re-purposed into a "successful" geothermal well.

Beyond that, oil companies looking to venture into renewable resources could partner with the geothermal companies and gain important insights and know-how.

2.3 Benefits for Geothermal Companies

Geothermal energy projects are capital intensive **(El-Jummah et Philip, 2014)**. Once the plant is built the energy fuel is practically free, and the OPEX becomes mostly operation and maintenance costs and personnel salaries. Reconnaissance, exploration, drilling (both for exploration and production), and the building of a power plant, means an estimated 6 years will have passed before a project can deliver electricity to the grid. For a low-temperature project, drilling may make up to 20 % of development cost, with the number going up to 50 % for high-temperature projects **(Stefansson, 2001)**.

As we see, most of the costs associated to geothermal development occur at a project's beginning. Not only that, but with 6 years this process is time intensive. For existing oil wells the reconnaissance, exploration, and drilling are already done. At least 3 years of time and a substantial part of the costs are saved.

Reconnaissance	1 year
Surface exploration	1 year
Exploration drilling	1 year
Production drilling and power plant	3 years
TOTAL	**6 YEARS**

Table 1: Estimated project development timeline using the development strategy recommended by **(Stefansson, 2001)**

The international oil industry has millions of oil wells drilled all around the globe. Wells which, to the most part, come with useful exploration data. These reservoir and well properties would save a developer millions on reconnaissance and exploration, and with the wells already drilled and in place the only thing remaining would be the power plant construction and the conversion of the well to optimize it for its new purpose. For all the time and costs that are saved, developers will financially compensate the oil companies in return. A win-win for both sides.

CHAPTER 3: GEOTHERMAL ENERGY

Geothermal Energy can be used to produce electricity. It can also be used for heating purposes. The main focus of this thesis is the production of electricity, therefore we will describe how this is done in more detail. Production of heat will only be considered when it is present in addition to production of electricity, not separately.

3.1 Organic Rankine Cycle (ORC)

Geothermal sources below 150 °C are considered to be medium temperature. The bottomhole temperature of most oil wells is indeed below 150 °C. At these temperatures the efficiency of the regular Rankine cycle using water-steam as its working fluid decreases. If the bottomhole temperature further drops below the boiling point of water, it becomes not only inefficient, but completely impossible to vaporize the water in the first place.

However, Organic Rankine Cycles (ORC) use high molecular weight organic fluids with boiling points below that of water **(Siemens, 2014)**. This has made it possible to produce electricity from temperatures way beneath the boiling point of water. In fact, an ORC power plant in Fairbanks, Alaska currently generates electricity with a maximum produced water temperature of 74 °C **(Holdmann, 2007)**. So far this has been the lowest temperature successfully used in a geothermal electricity project.

3.1.1 The ideal Rankine Cycle

The general setup of an ORC is identical to that of a regular Rankine cycle. It includes a pump, a heat source (the oil well in our case), a turbine, and a condenser. The main difference between the Rankine Cycle and the Organic Rankine Cycle is the working fluid used to generate electricity. Regular Rankine Cycles use water-steam as their working fluid, while Organic Rankine Cycles use an organic working fluid instead.

Since both cycles are identical apart from their working fluids, we will start by describing the Ranking Cycle:

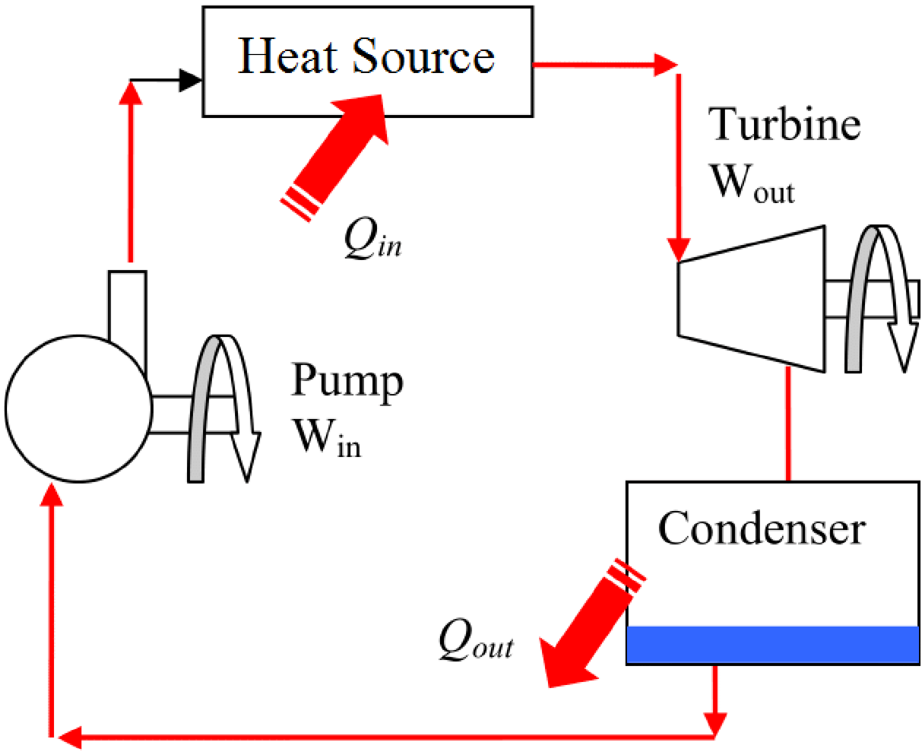

Figure 1: The ideal Rankine cycle **(Bahrami)**

In an ideal Rankine cycle all four processes are reversible:

1-2: The working fluid (state 1) enters the pump as a saturated liquid and is compressed isentropically to a higher pressure (state 2)

2-3: The fluid is heated at constant pressure. It comes out of the heat source as superheated vapor (state 3)

3-4: The superheated fluid expands isentropically in the turbine and produces work. It exits the turbine as high quality vapor (state 4)

4-1: The steam is condensed at constant pressure. This is a return to state 1 at which the fluid will re-enter the pump

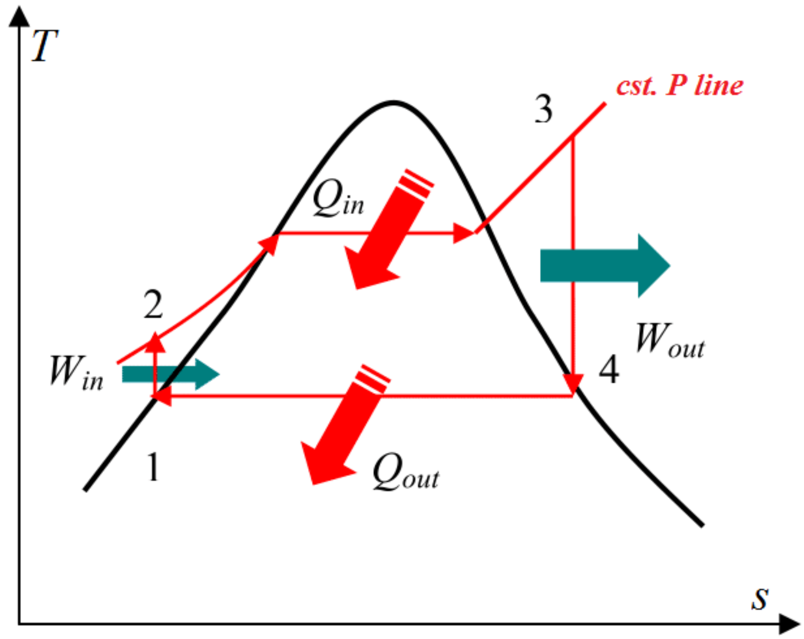

Figure 2: T-s diagram of an ideal Rankine cycle **(Bahrami)**

The **first law efficiency** (thermal efficiency) for an ideal Rankine cycle can be written as:

$$\eta_{th} = \frac{w_{net}}{q_{in}}$$

Knowing that:

$$w_{pump,in} + q_{in} = w_{turbine,out} + q_{out}$$

We deduce that:

$$w_{net} = w_{turbine,out} - w_{pump,in} = q_{in} - q_{out}$$

And hence:

$$\eta_{th} = \frac{w_{net}}{q_{in}} = 1 - \frac{q_{out}}{q_{in}}$$

The **maximum thermal efficiency** is limited by the **second law of thermodynamics** and is given by:

$$\eta_{max} = \frac{T_H - T_L}{T_L}$$

Where T_H is the temperature at which heat is transferred to the working fluid and T_L is the temperature at which heat from the working fluid is rejected to the condenser **(Bilbow et Brasz, 2004)**.

3.1.2 The Rankine Cycle in practice

In reality the processes are accompanied by irreversibilities caused by heat loss to the environment as well as fluid friction.

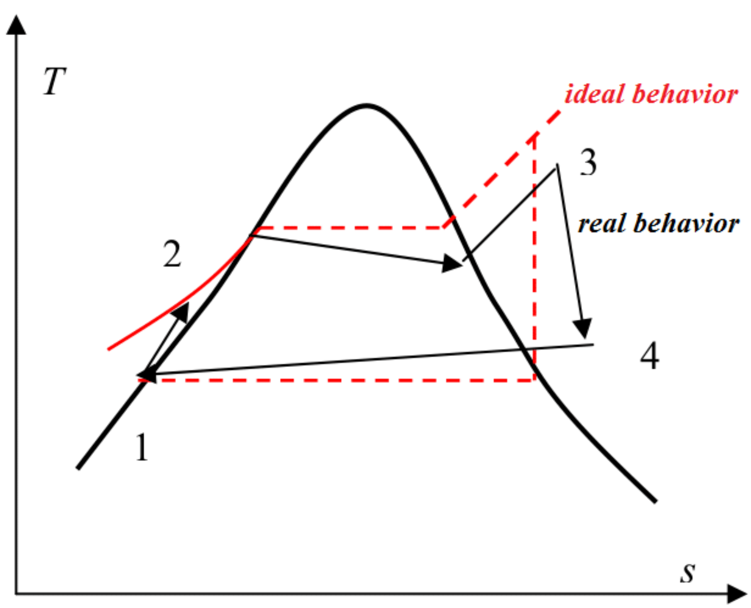

Figure 3: T-s diagram of an actual Rankine cycle
(Bahrami)

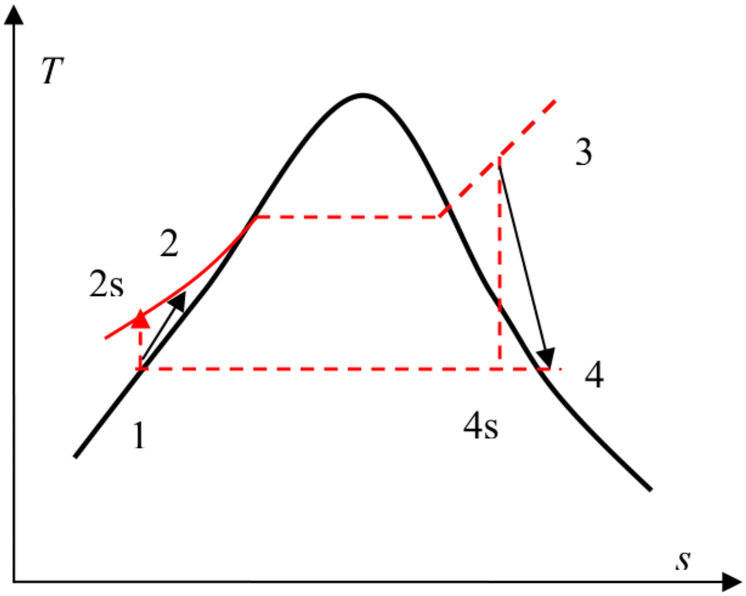

Figure 4: Real behavior of the pump and turbine compared to the isentropic behaviour **(Bahrami)**

For the pump and turbine, the isentropic efficiencies measures the deviation in their behaviors from an ideal isentropic behavior. They are given by:

$$\eta_P = \frac{w_s}{w_a} = \frac{h_{2s} - h_1}{h_{2a} - h_1}$$

$$\eta_T = \frac{w_a}{w_s} = \frac{h_{2a} - h_1}{h_{2s} - h_1}$$

h is the enthalpy. w_a represents the actual work, while w_s represents the isentropic work. η_P and η_T are the isentropic efficiency of the pump and the turbine respectively.

3.1.3 ORC working fluids

Unlike water-steam cycles working exclusively with water, ORCs have hundreds of possible organic fluids displaying different thermophysical behavior as well as different safety and environmental properties. The main types of working fluids are PFCs, HFCs, CFCs, HCFCs and hydrocarbons. The properties of these working fluids aren't always as well-known as those of water especially when the working fluid is a mixture of two or more separate fluids. Selecting the right working fluid is crucial and will vary on a case by case basis. Besides thermodynamic and heat exchange considerations, environmental and safety criteria such as toxicity and flammability have to be taken into account **(Nouman, 2012)**.

3.2 Combined Heat and Power (CHP)

Combined Heat and Power (CHP), is the cogeneration of electricity and thermal energy. Thermal energy can be recovered from exhaust gases in the case of engines. In the case of turbines, the thermal energy is recovered from the fluid exiting the turbine. For the scope of this thesis, we will be concerned with the latter example.

The recovered heat can be used for industrial purposes (chemical plants, water treatment, refineries, etc…), commercial purposes (hotels, universities, hospitals, etc…), and district heating. The type of application that is best suited in each case will depend on how much heat is recovered, as well as practical considerations such as infrastructure availability and proximity of the end user to the heat source. Additionally the thermal energy gained through CHP can be used for certain refrigeration applications such as absorption chillers. Depending on the application and on the system parameters, the heat will be recovered as steam, hot water, or as heated process gas.

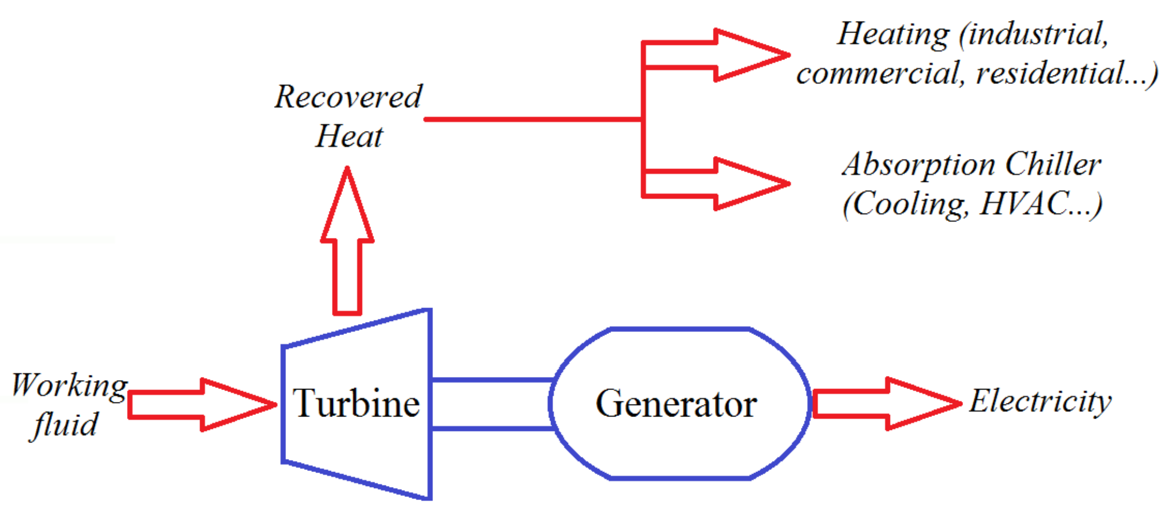

Figure 5: CHP configuration with heat recovered from the exit gas

Systems that produce heat and power together in a CHP model have a substantially higher energy efficiency when compared to systems that produce heat and power from separate sources. Energy efficiency for CHP systems ranges from 65 % to 85 % (HHV), while separate heat and power systems usually achieve a total energy efficiency somewhere between 45 % and 55 %. **(DOE, 2017)**

3.3 Closed Single Cycle vs. Open Dual Cycle

In a closed single cycle, the working fluid is immediately heated by the formation with nothing in between. It is called a closed cycle because the well's bottom is sealed (as will be shown later), and hence the fluid circulates in a closed cycle.

In an open dual cycle the formation fluids are produced first. These fluids, heated by the formation they were produced from, will in turn be used to heat the working fluid, and is therefore called a dual cycle. It is open since the well is still open and producing fluids.

One advantage of single cycles is that they are generally more efficient than dual cycles. In fact in dual cycles the formation heats the extracted fluid first which then heats the working fluid. In that way additional heat is lost resulting in lower overall efficiency.

Another advantage of single cycles is their simplicity, and since the well is closed they also avoid general problems associated with producing reservoir fluids, such as corrosion of pipes and equipment. In a closed cycle where only the working fluid is circulating, corrosion and other issues are more easily predicted and dealt with, because the temperature and the pressure of the fluid are known at all points of the cycle.

3.3.1 Closed Single Cycle

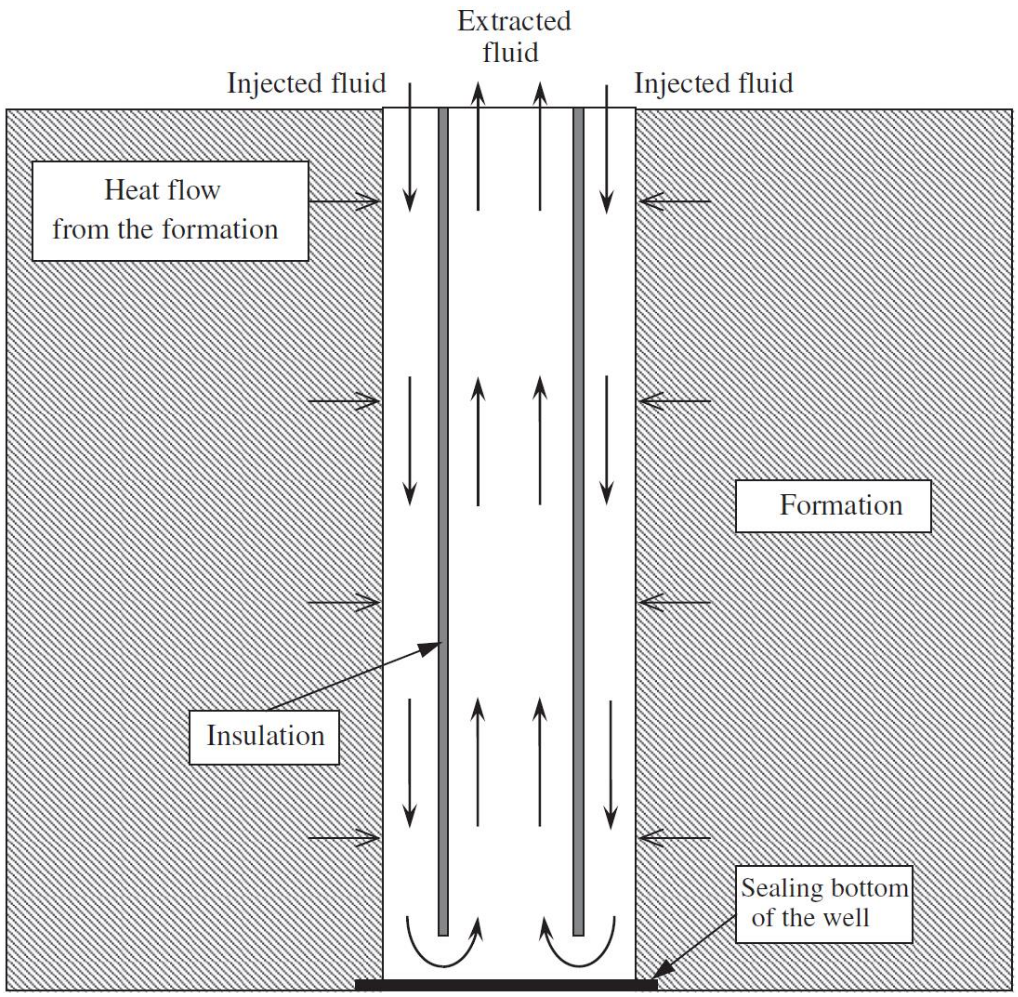

Figure 6: Heat extraction through a sealed abandoned well **(Cheng et al., 2014)**

The closed single cycle requires sealing the well. Therefore it is only applicable in the case of abandoned wells that are no longer producing. The working fluid is pumped down the sealed well where it is heated directly by the formation's energy. Two general layouts exist for this cycle: the DPGS (Direct Power Generation System) and the FPGS (Flash Power Generation System). Both layouts will be discussed and compared below.

Even though single cycles are usually more efficient, they are impossible to implement for co-production since it is impossible to seal a well that is still producing.

3.3.1.1 Direct Power Generation System (DPGS)

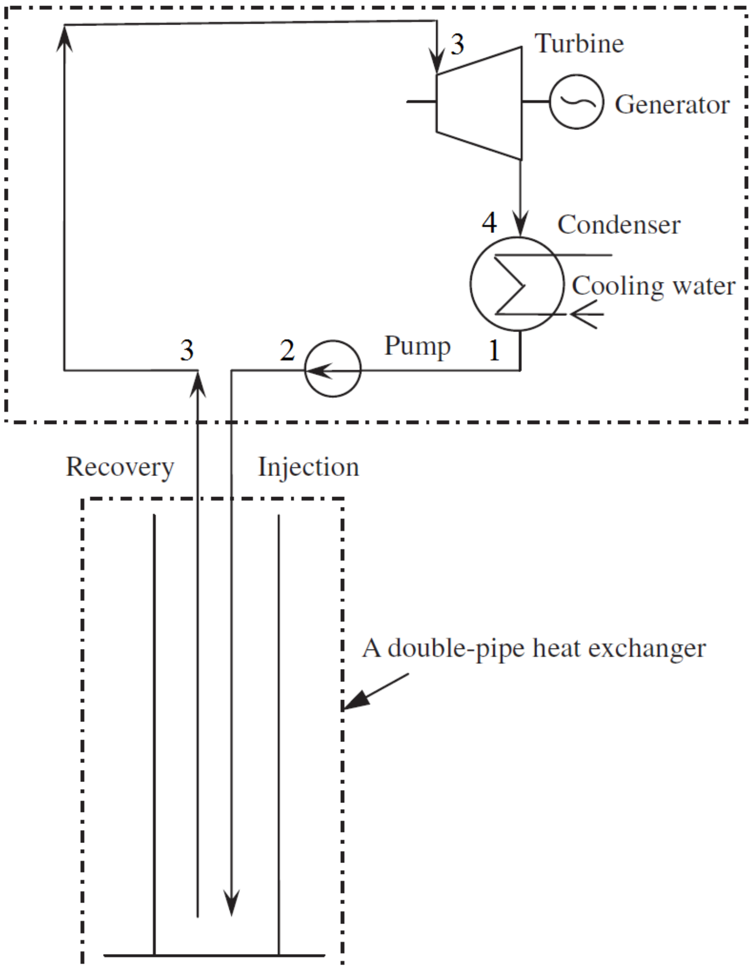

Figure 7: DPGS **(Cheng et al., 2014)**

In a DPGS, all of the working fluid is heated to a supercritical state and is thus entirely used to generate power in the turbine.

1-2: The fluid, at state 1, is boosted by a pump to state 2

2-3: The fluid is injected down the well. The well-formation system acts as a double pipe heat exchanger. The fluid traveling down the annular space is heated by the formation's thermal energy. It is recovered from the well at state

3-4: : At this stage, the working fluid is a supercritical fluid and is sent to the turbine to generate energy. Inside the turbine, the fluid is expanded. It loses both temperature and pressure, and exits the turbine at state 4

4-1: The fluid enters the condenser at state 4 where it is cooled by water or air. It leaves the condenser as a liquid (state 1)

The liquid is then injected down the well by the pump and the cycle is completed. The advantage of DPGS over FPGS is that the entire liquid is at a sufficient temperature and pressure to work in the turbine, and thus all of the fluid is used for energy generation.

3.3.1.2 Flashing Power Generation System (FPGS)

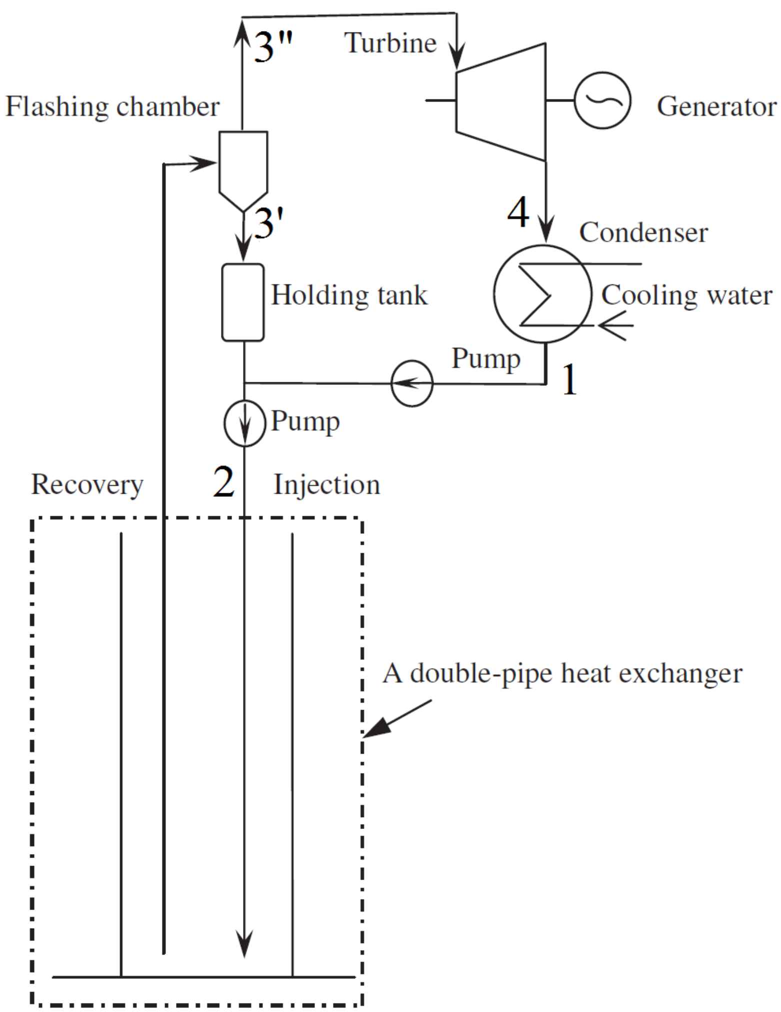

Figure 8: FPGS **(Cheng et al., 2014)**

The main difference between an FPGS and a DPGS is that the working fluid leaving the well in an FPGS is sub-cooled.

The working fluid has to go through a flashing chamber where it is expanded and divided into a saturated vapor (state 3") and a saturated liquid (state 3').

The saturated vapor goes to the turbine, whereas the saturated liquid goes to the holding tank.

The liquid exiting the holding tank is pumped down the well together with the liquid exiting the condenser.

Logically, the overall efficiency of this process is lower since part of the fluid is converted to liquid before entering the turbine, and therefore the heat it was holding will be lost. It's therefore only used to exploit sources where the formation's energy isn't sufficient to permit a DPGS.

3.3.2 Open Dual Cycle

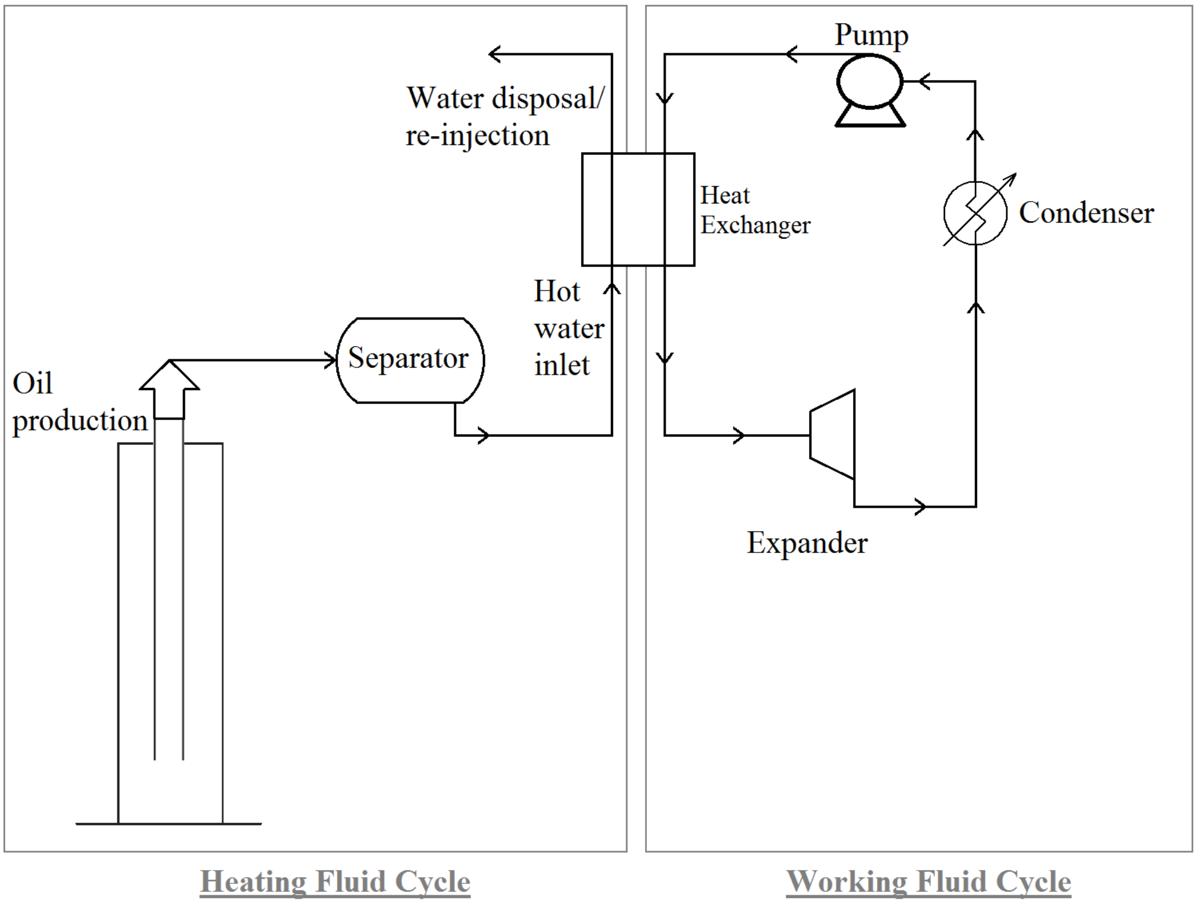

Figure 9: Open Dual Cycle

The dual or binary cycle is made up of two separate cycles. The first is the heating fluid cycle, in this case water. The other one being the working fluid cycle. Water and oil are produced from an active well. After passing through a separator, the water flow is diverted to a heat exchanger where the hot water exchanges heat with the relatively cooler working fluid. After exiting the heat exchanger, the water is either disposed of or used for re-injection depending on each case. In some cases, heating the working fluid before separation has also been discussed. The advantage of this is that the unseparated oil and water stream has a higher temperature than the separated water stream.

As for the working fluid cycle, it is equivalent to the single cycle. The only difference is the heat source. In this case the heat is delivered by the water and not by the formation. As for the expander, the condenser, and the pump, they follow the same principles described for single cycles.

CHAPTER 4: PRODUCING WELLS

The main parameters that determine a project's feasibility are the geothermal fluid's temperature, the total flow rate, and the water cut. The water cut represents "the ratio of water produced compared to the volume of total liquids produced" **(Schlumberger Glossary)**. The temperature needs to be at a minimum in order to adequately vaporize the working fluid. The higher that temperature, the better. The lowest fluid temperature ever used to produce electricity was 74 °C **(Holdmann, 2007)**. If the temperature is high enough, higher water flow rates means a higher volume of working fluid can be vaporized.

In order to evaluate the technical and economic feasibility of co-production some authors defined a parametrical approach based on the definition of a number of indexes, each of them including the technical and economic parameters of interest. For example, researchers at the "Sapienza Università di Roma" identified nine parameters. These nine parameters take into account the installed power of the electric plant, the fluid flow rate, the fluid's outlet temperature, the need for pumping to aid fluid production (when applicable, pumping consumes energy which reduces the overall energy efficiency of the system), Re-injection (when applicable), the corrosiveness of the geothermal fluid, the environmental impact of installing a power plant, the social impact of installing a power plant, and the payback time of investment (i.e. the time needed for the profits to break even with the costs of installing and operating the power plant). Each one of these parameters is assigned an index whose value ranges from 0 (unfavorable) to 1 (favorable), and each index is given a "weight" that corresponds to its importance. For a given project, a total index can thus be calculated from these different indexes to facilitate making a decision on whether to implement co-production or not **(Alimonti et Soldo, 2015)**. Similar results have also been discussed in **(Al-Mahrouqi et Falcone, 2016)**.

For the scope of this chapter we will resume by discussing case studies as well as successful in-field implementations of electricity and oil co-production.

For the studies presented in this chapter, most of the data, images, and tables presented are either taken directly from, or based on information found in a single reference or two at most. For "Geothermal Energy in the L.A. Basin" most of the data is taken from **(Bennett, 2012)** and **(Bennett et al., 2012)**. "Wytch Farm Case Study" was taken from **(Falcone et al., 2017)**. "Huabei Oilfield, China" is based on **(Hu et al. 2012)**. "Rocky Mountains Oil Testing

Facility" relies on **(Johnson et al. 2011)**, and "Laurel, Mississippi" relies on **(ElectraTherm, 2012)**. To avoid repeating these reference multiple times, they will be listed only once at the beginning of each part. In the rare cases where a different paper or report was used, it will be mentioned in the text.

4.1 Geothermal Energy in the LA Basin

Project stage: Study
Energy type: Electricity only
Estimated total power output: 7.43 MW from 6 fields
NPV: 41.2 million $
Reference: **(Bennett, 2012)** and **(Bennett et al., 2012)**

The fields of the Los Angeles Basin area are mature fields that have been in production since the early 1900s. They show great characteristics for geothermal exploitation, having an average water cut of 97 % **(DOGGR, 2009)** and a relatively high geothermal gradient of 2 °F/100ft (36 °C/km) **(Buening et al., 1993)**. A study by Kara Bennett at the Stanford University to size the potential power production and the profit (or losses) that would come along. The STARS (Steam, Thermal, and Advanced Processes Reservoir Simulator) numerical simulator was used to run multiple scenarios and compare them by their NPV. STARS is commercialized by Canadian company "CMG Ltd".

The main non-technical advantage of these fields compared to similar studies is that they are located in vicinity to residential areas, with most of the oil wells being fed by (and hence connected to) the local electricity supply. In a scenario where electricity were to be produced on site, it would be sold directly into the grid with no additional expenses on infrastructure. The fields have been producing since the early 20th century, and with their maturing water flooding has been used. More interestingly, the Wilmington, Richfield, Huntington, Newport West and Inglewood fields have made use of steam flooding in the past, which opens the potential producing the previously injected heat **(Barrufet et al., 2010)**.

DOGGR (Division of Oil, Gas, & Geothermal Resources) data resulted in a gradient of roughly 33 °C/km, similar to Buening et. al's 36,5 °C/km. From the same database, 189 out of the 365 reservoirs have initial temperature data. Out of the ones with available data, 11 % and 32 % had temperatures above 100 °C and 80 °C respectively.

From the fields named earlier, the Wilmington field is produced offshore on artificial islands. Constrained by the small area of these islands, it uses ESPs for oil production and thus has a high demand for electricity. With a high water cut and temperatures exceeding 140 °C it is an optimal candidate for energy generation. Since some reservoirs in this field flow at much lower temperatures, they were excluded from the simulation. And since the entire production is comingled, additional costs were calculated to be able to separately flow the useful hot reservoirs from the relatively colder and useless ones.

The numerical model was used to simulate one injector/producer pair in a closed system. Geological properties were taken from an analog sandstone reservoir and applied for all fields. Reservoir size, temperature, production and injection rates were changed according to each field. The results of the injector/producer pair were then scaled to be representative of an entire field. It was assumed that heat exchange between produced fluids and working fluid occurs before separation of oil and water. The results were used to calculate the NPV. For this, upfront costs such as the installment of the binary power plant and piping were assumed at 1900 $ per kW **(GeothermEx, 2004)**, and the electricity was used immediately on site to offset energy costs. The reasoning for this is that selling electricity to the grid brings less profit than one would have to pay to purchase it. O&M costs and a discount rate of 5 % were considered over a 30 years lifetime. A capacity factor of 0.85 was taken. The capacity factor of a power plant is the ratio of its actual production to maximum production. The assumptions for the simulation are detailed in table 2.

Economic assumptions		Technical assumptions	
Electricity price	0.08 $/kWh	Ambient Temperature	24 °C
CAPEX	1,900 $/kW	Injection Temperature	35 °C
O&M	0.014 $/kWh	Power Plant Outlet Temperature	55 °C
Capacity Factor	0.85		
Discount rate	5 %	Porosity	0.30

Table 2: Economic and Technical Assumptions **(Bennett et al., 2012)**

The production potential for all 49 fields was estimated at 8.2 MW. With adequate cooling, using water instead of air, the outlet temperature can be brought down from 55 °C to 35 °C. This would increase the total potential for production from 8.2 MW to 18.7 MW. For the purpose of this study, an outlet temperature of 55 °C was considered and hence a total potential of 8.2 MW. An arbitrary minimum NPV of 1 million $ was selected to rate projects as profitable or not. With the economic assumptions in mind, the minimum size of a power plant has to be at least 180 kW. 6 out the 49 fields showed the possibility of an output over 180 kW, the other 43 fields were considered too small. These 6 fields alone accounted for 7 MW out of the 8.2 MW total.

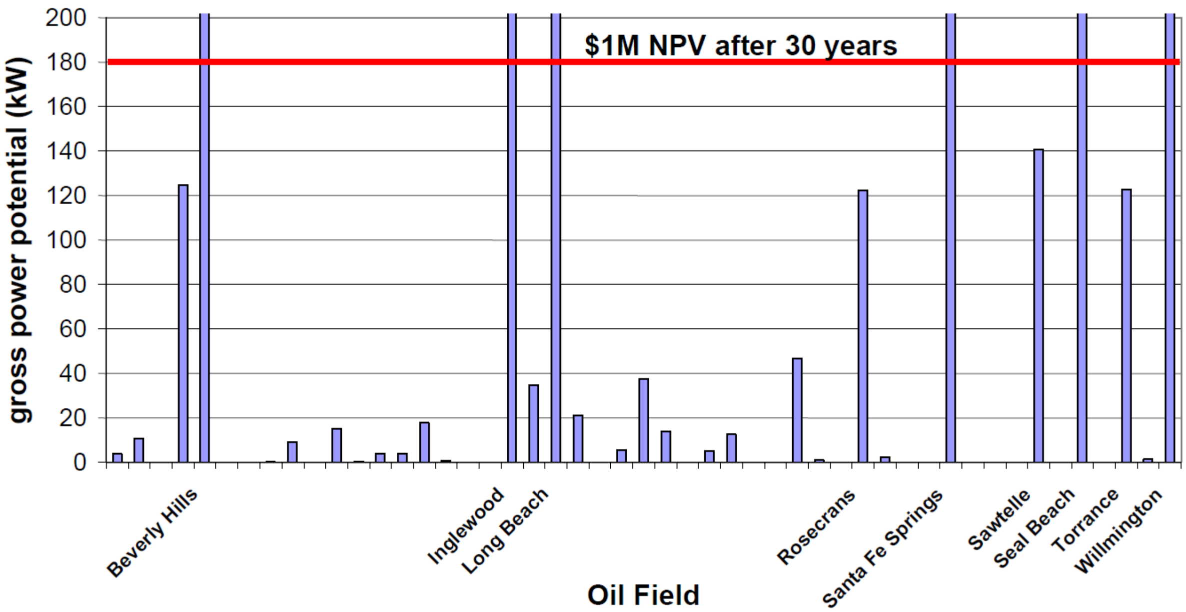

Figure 10: The profitability threshold for the NPV is at 1 million $ (The graph was cut off at 200 kW to fit the smaller fields) **(Bennett et al., 2012)**

Table 3 on the next page shows the results for the 6 fields that were deemed profitable. The power output is equivalent to the power plant size that a given field can sustain over a lifetime of 30 years:

Field	Power Output (kW)	NPV (million $)
Beverly Hills	1,080	6.0
Inglewood	580	3.2
Long Beach	530	2.9
Santa Fe Springs	1,100	6.1
Seal Beach	590	3.3
Wilmington (selected reservoirs)	3,550	19.7
Total	**7,430**	**41.2**

Table 3: Power Output and NPV by field **(Bennett et al., 2012)**

The three most critical parameters of any geothermal co-production project are the reservoir temperature, the total flow rate, and the water cut. Table 4 on the next page displays these parameters for the six fields that were determined to be economically viable.

Field name	Average Reservoir Temperature (°C)	Total liquid rate-March 2011 (kg/s)	Water cut-March 2011 (%)	NPV ($)
Beverly Hills	97	49	92	6.0
Inglewood	68	674	97	3.2
Long Beach	79	230	97	2.9
Santa Fe Springs	73	183	98	6.1
Seal Beach	100	43	95	3.3
Wilmington (Only the selected reservoirs with high enough temperature; UT, LT, UP, Ford, 237)	77	856	97	19.7

Table 4: Technical parameters and the resulting NPV for each field **(Bennett et al., 2012)**

The fields of Beverly Hills and Seal Beach exhibit the highest average reservoir temperatures, while the Wilmington field had the highest total production. The water cuts of all fields are similar, ranging from 92 % to 98 %. Interestingly, the field that turned out to be the most profitable for geothermal exploitation was the field with the highest production and not the field with the highest temperature.

4.2 Wytch Farm Case Study

Project stage: Case Study
Energy type: Electricity only, Electricity and Heat (CHP), and Heat only were all studied
Estimated net power: Combined 2.25 MW of electricity on 2 sites plus heating for 2600 households
NPV: Variable, 10.63 million £ at 10 % discount
Reference: **(Falcone et al., 2017)**

4.2.1 Introduction

The Wytch Farm oilfield is located in Dorset in the South of England. It is Western Europe's largest onshore oilfield. It was discovered in 1973 and production started in 1979. The field's production peaked at 110,000 bpd but was as low as 15,000 bpd in 2011 when its then operator BP decided to sell it off to Perenco UK. **(The Guardian, February 22nd, 2011)** As of 2017 the Wytch Farm Oil Field had a water cut around 95 %. This water cut is expected to rise over the next 25 years.

For the numerical simulations, the model was kept flexible to take into consideration time changing parameters like the increasing water cut.

The economic feasibility was calculated until the year 2040 after which Perenco's production license expires. In the case of electricity generation, a dual ORC plant would be used. For district heating purposes, a heat exchanger is to be used. In case of a CHP implementation, a dual ORC plant would be used to generate electricity, followed by a heat exchanger to recover additional heat for district heating purposes.

The Wytch Farm Case Study is only concerned with the sites M and F (See Fig. 11 below).

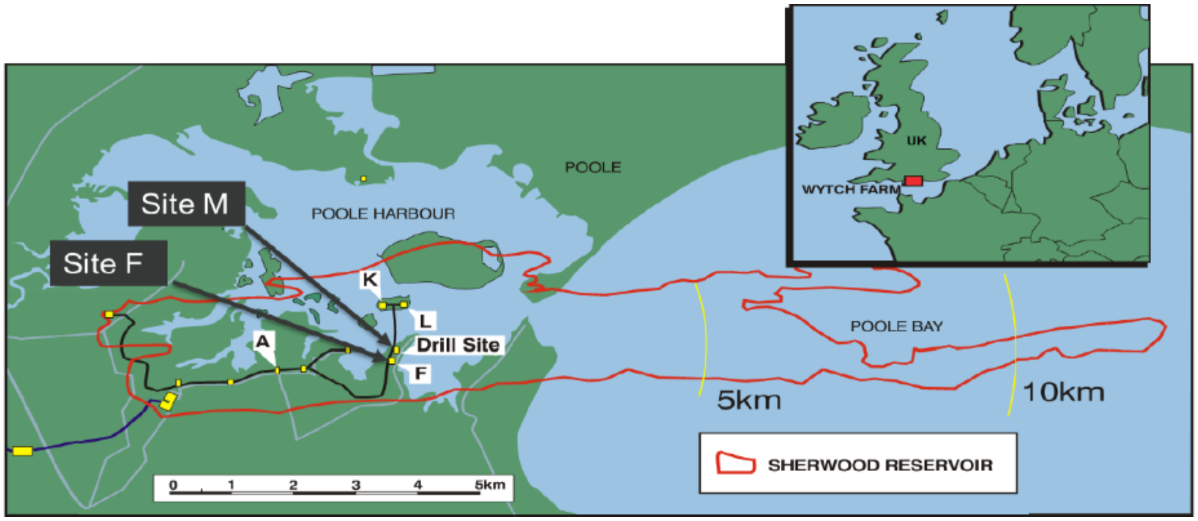

Figure 11: Location of the sites M and F within the Wytch Farm Field **(Falcone et al., 2017)**

4.2.2 Site Specific Parameters and Heat Exchange Output Power

The produced fluids are highly corrosive (contain chlorides). The pressure upstream of the separator is between 15 and 50 bars. Downstream of the separator the pressure is more stable as it varies from 12 to 16 bars. Site M produces 160,000 bwpd which can be increased to 180,000 bwpd. The geofluid downstream of the separator (water with impurities coming out of the separator) has a temperature of 65-67 °C. Site F produces 90,000 bwpd which can be increased to 130,000 bwpd and the geofluid temperature downstream of the separator is approximatively 66 °C.

The output power is the energy transferred from the geofluid to the working fluid inside the heat exchanger. In order to calculate the output power, an estimation of the efficiency of the heat exchange is needed. By comparing similar previous projects an estimation was obtained:

$$\eta = 0.0802T_{in} - 0.1072$$

The inlet temperature of the geofluid is in (°C). It is the temperature of the geofluid entering the heat exchanger, which means it is equal to the temperature of the geofluid exiting the separator.
The efficiency is obtained in (%). The power output "Q" inside the heat exchanger can be calculated as:

$$Q = c_p m (T_{in} - T_{out}) \eta$$

c_p is the specific heat capacity of the geofluid and m is the total mass flow rate of the geofluid. T_{out} is the temperature of the geofluid exiting the heat exchanger.

Sites F and M have similar geofluid temperatures as mentioned above (65 -67 °C at site M and 66 °C at site F). Therefore they have similar thermal efficiencies of 5.2 %. The output power at site M was calculated in the range of 1100-1450 kW, and in the range 700-1120 kW at site F. The output power varies depending on the mass flow rate as well as the outlet temperature of the geofluid. The parameters used and the results are shown in table 5.

Site M		**Site F**	
T_{in} (ºC)	67	**T_{in} (ºC)**	66
η (%)	5.2	**η (%)**	5.2
Mass flow rate (kg/s)	290-330	**Mass flow rate (kg/s)**	170-220
T_{out} (ºC)	50-55	**T_{out} (ºC)**	41-46
Q (kW)	1100-1450	**Q (kW)**	700-1120

Table 5: Power output of the two sites **(Falcone et al., 2017)**

It is to note that the efficiency and the output power calculated above are not the efficiency and output power of the ORC, but the efficiency and output power of the heat exchange between the heating fluid (geofluid) and the working fluid of the ORC. After the heat exchange, the geofluid is injected back into the reservoir.

4.2.3 Organic Working Fluid Selection

The working fluid has to be carefully selected according to the cycle's parameters. The following are the selection criteria in order of importance:

- The critical temperature of the fluid must be higher than the heat source's temperature (65-67 °C) to ensure subcritical operation

- The fluid should be able to operate at a moderate pressure throughout the cycle. This isn an economic requirement not a technical one. Operating at low pressures limits the size of the plant equipment and keeps the CAPEX low

- Fluids that exhibit retrograde behavior are preferred to ensure the fluid remains superheated after expansion. This prevents liquid formation in the turbine which can cause damage

Based on this, 6 fluids were shortlisted to be simulated in the model: R134a, R152a, Isobutane, Butane, Propane, and Ammonia.

4.2.4 System Model

4.2.4.1 Fluids

The model was designed to be flexible. It can optimize the electric power output for any given heat source and heat sink, and any organic fluid can be used as the working fluid.

- The heat source is considered to be the geofluid. The inputs are the mass flow rate, the remaining oil percentage in the water after separation, the oil API gravity, the specific heat capacities of the oil and of the water, and the stream's temperature and pressure

- The heat sink (namely the condenser fluid) is salty sea water at an average temperature of 10 °C. With the oil field being close to the shore, it is easily accessible and has a low cost. For the sake of the model it can be reasonably approximated to be pure water since it has similar thermodynamic properties. The temperature and pressure of this cooling fluid are model inputs

- For the working fluid, the selection process was already explained above

4.2.4.2 Optimizing the output power

The highest mass flow rate of the working fluid and the highest turbine inlet pressure do not necessarily generate the maximum gross output power. Instead, the maximum gross power output from the turbine is reached for the maximum difference between turbine inlet pressure (TIP) and turbine outlet pressure (TOP), so the highest possible TIP and the lowest possible TOP are desired.

For a fixed mass flow rate of the working fluid, the higher the mass flow rate and temperature of the geofluid, the higher the heat flux to the working fluid and hence the higher we can adjust the TIP while making sure the working fluid is still saturated or superheated when it enters the turbine. The TOP however is limited by the condenser. The aim is to have the TOP as low as possible, while making sure the fluid exiting the condenser is 100 % liquid before it enters the pump. Using these constraints, the model calculates the optimal mass flow rate of the working fluid and TIP that would result in the highest possible gross power output.

The example given in figure 12 below shows the optimal combination of mass flow rate and TIP for Isobutane (R600a) simulated at the Wytch Farm site M.

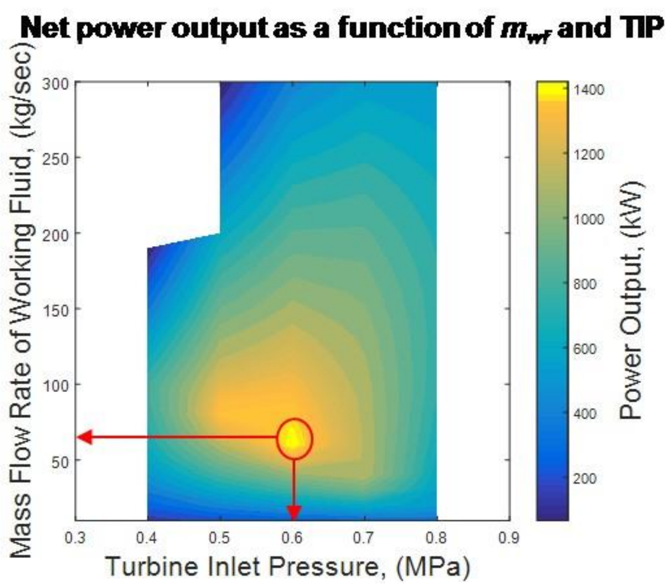

Figure 12: Optimized TIP and Mass Flow Rate (**Falcone et al., 2017)**

4.2.4.3 Optimizing the Heat Exchanger

Changing the current oil pipelines would be too risky and too inconvenient for the operator. Instead, the heat exchanger should be set up in a way to keep the current pipeline layout intact. A clamp-on double pipe heat exchanger fulfils this requirement. A second pipe is simply clamped onto the already existing pipeline (See Fig. 13 below).

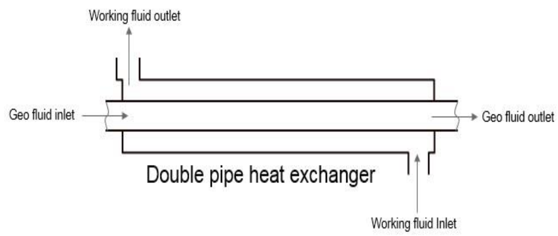

Figure 13: Simple Clamp-on Double Pipe Heat Exchanger **(Falcone et al., 2017)**

A possible way to optimize the system is by setting up the heat exchanger upstream of the separator because the geofluids are at a higher temperature before the separation. A drawback is the limited pipe length from the wellhead to the separator which limits the exchange surface. Adding spikes or using a helical heat exchanger can overcome the exchange surface limitation (See Fig. 14 below: left side shows the design with spikes, right side shows the helical design).

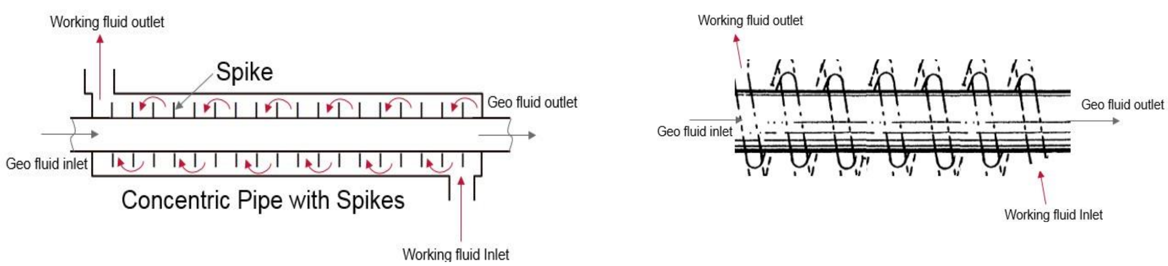

Figure 14: Improved Designs of the Double Pipe Heat Exchanger **(Falcone et al., 2017)**
(the left side shows the design with spikes; the right side shows the helical design)

4.2.4.4 Condenser and Optimal Net Power Output

A higher flow rate of the cooling fluid, i.e. sea water, increases the overall thermal efficiency of the system, while also increasing the parasitic load of the sea water pump. The mass flow rate of the cooling fluid should be optimized to render the highest net power output of the system. The optimal value was calculated at 1000 kg/s. This exceeds environmental recommendations. Therefore an adiabatic cooler should be considered as an alternative before the system is implemented.

4.2.5 Model Results

Results were obtained for generating electricity for both sites M and F. Additionally for site M heating only and CHP (both electricity and heating) were considered as well. No heating only and no CHP studies were made for site F.

4.2.5.1 Electricity only

It was found that site M can generate 1.4 MW of electricity while site F can generate 0.850 MW of electricity.

4.2.5.2 CHP

The geofluid enters the heat exchanger at a temperature close to 65 °C with little variation between the sites M and F. It exists the heat exchanger at 47-52 °C. At this temperature the geofluid is still useful for heating. As already discussed, the geofluid is highly corrosive, it also contains gas and can cause scaling. Therefore it can not be directly circulated inside the district heating pipes. Instead it is passed through a second heat exchanger where the heat is transferred to fresh water. The heated fresh water can then be circulated to heat households. We assume the geofluid enters the heat exchanger at 47 °C, and we consider a pinch point of 5 °C. The pinch point is the point inside the heat exchanger with the lowest difference in temperature between the hot and the cold fluids, which means the fresh water can be heated up to 42 °C (5 °C below 47 °C). This temperature is high enough for under floor heating, but not for heating domestic water. This could be overcome by using heat pumps to bring the fresh water's temperature up to 50 °C. The fresh water would return at a temperature of 25 °C. (See Fig. 15 below)

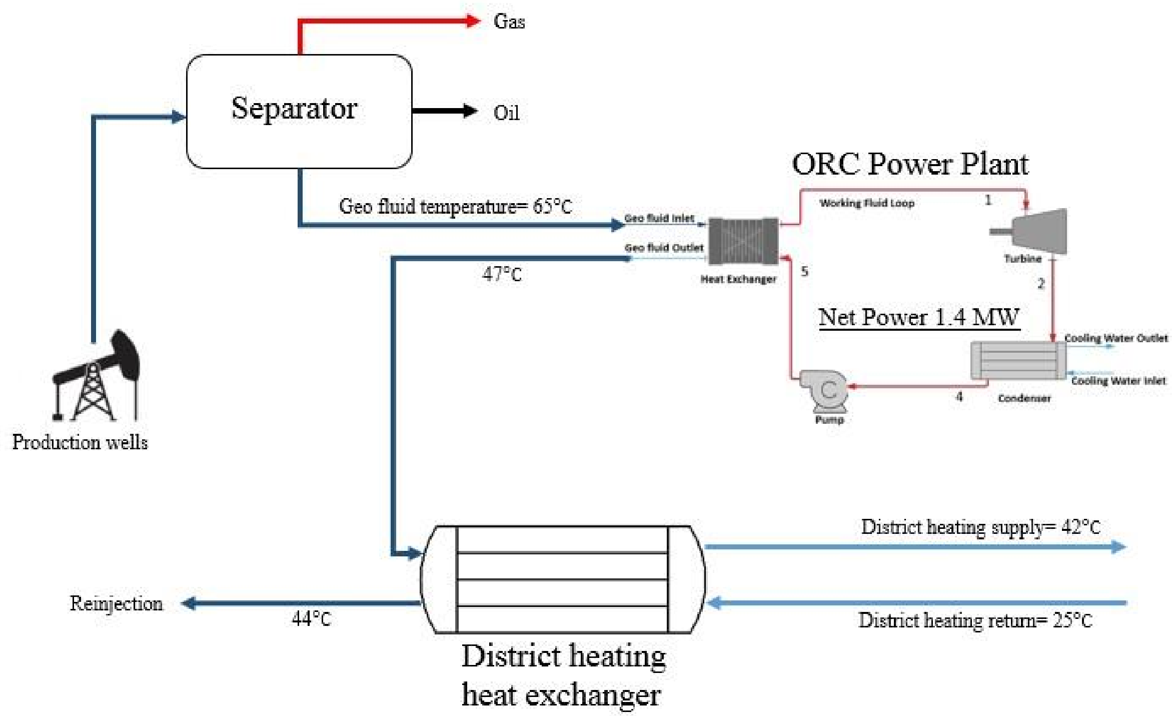

Figure 15: CHP layout at site M **(Falcone et al., 2017)**

With a geofluid mass flow rate of 290 kg/s and a temperature of 65 °C, site M can generate 1.4 MW of electricity and 4.24 MW or 37 GWh yearly in heat. This would cover 2600 households. The closest community to Wytch Farm site M is at a distance of 4 km, with proper insulation the temperature drop in the heating pipeline can be kept under 0.5 °C. The study did not include the heating potential of site F.

4.2.5.3 Heating only

Heating only might be an attractive option because of government subsidies that support the building of heat networks. In this scenario only half of the geofluid's flow would be necessary to generate 62 GWh per year. This is enough to serve 4350 households.

4.2.6 Economic Evaluation

The water cut was equal to 95 % in 2017. The water production is expected to remain constant and oil production is expected to decrease. This will cause a gradual increase of the water cut. The reservoir temperature can be assumed to remain constant according to the operator's simulations. The operator plans to shut down the wells with marginal oil production. This explains the sudden drop in water production shown in fig. 16. If the energy production generates enough income to offset the marginal wells' OPEX, these wells might be kept on stream beyond 2028. However OPEX figures are confidential so this assumption is discarded for the economic evaluation, and energy production will be considered to drop after 2028 in accordance with the decrease in water flow. The license production ends in 2040 so the NPV of the project will be calculated from 2017 up to that point. Only electricity production was included for the economic viability.

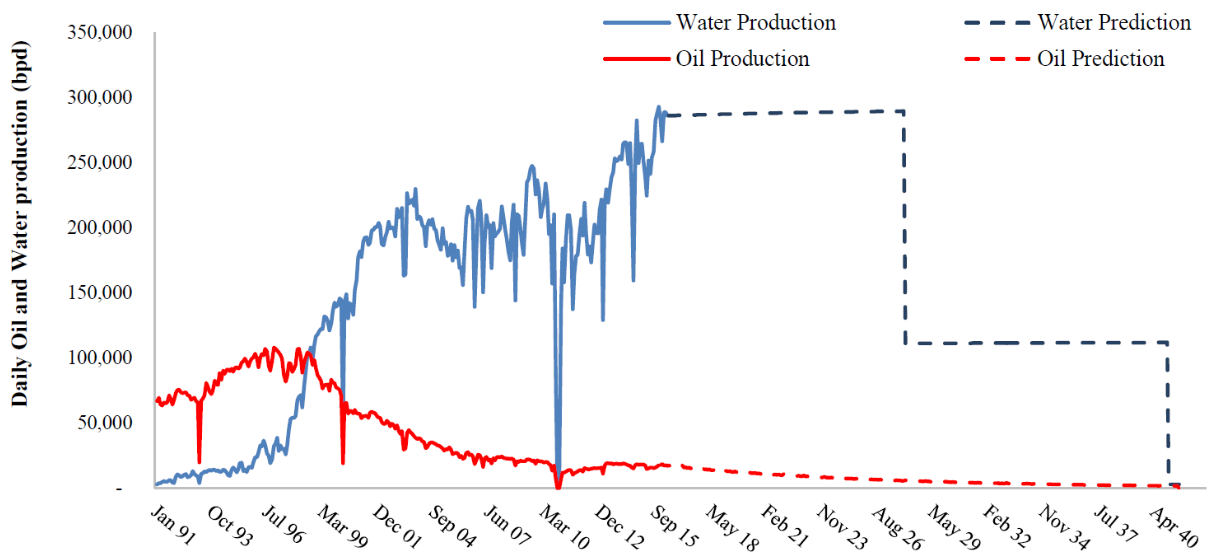

Figure 16: Projected Production Data for the Wytch Farm Field **(Falcone et al., 2017)**

4.2.6.1 Cumulative Power Generation

Power plant downtime is assumed to be 10 %. The condenser consumes 25 kW of power. It is also assumed that construction is completed in 2017 and production starts on January 2018. The cumulative power generated is obtained in table 6:

Location	Cumulative Power Generated (Jan 2018-Dec 2027)	Cumulative Power Generated (Jan 2018-Dec 2040)
Site M	115.50 GWh	185.22 GWh
Site F	73.16 GWh	116.27 GWh
Total	**188.66 GWh**	**301.49 GWh**

Table 6: Cumulative Power Generation by site **(Falcone et al., 2017)**

4.2.6.2 NPV

Using the electricity on site would save 60 £/MWh (the current purchase price paid by the operator). Nationwide, large size consumers pay an average of 91.5 £/MWh. While the UK's Feed-In Tariff (FiT) allows electricity generated from renewable sources to be sold to the grid at a higher price, an estimated 143.5 £/MWh in 2016. All three choices were considered in the original study. For this thesis we will only discuss the results obtained by selling the generated electricity through the FiT scheme since it is obviously the most profitable one. The discounted cash flow is calculated was calculated pre-tax and pre-interest at discount rates of 8 %, 10 %, and 12 %. The results are displayed below:

Value	Site M	Site F	Total
Installed Power (MW)	1.6	1.0	2.6
CAPEX (million £)	2.55	1.59	4.14
OPEX (million £)	3.00	1.89	4.89
Electricity Price (£/MWh)	143.5	143.5	143.5
NPV 8% (million £)	10.10	6.37	**16.47**
NPV 10% (million £)	8.22	5.19	**13.41**
NPV 12% (million £)	6.77	4.28	**11.05**

Table 7: NPV at Different Discount Rates **(Falcone et al., 2017)**

As is seen, the project would be profitable at all discount rates. If an average discount rate of 10 % is considered, the overall NPV of installing a co-producing power plant at both plants is equal to 13.41 million £. However, the installed heat exchanger would result in a pressure drop in the geofluid. An extra 160 kW will be consumed by re-injection pumps to keep the re-injection pressure constant. With this in mind, and using a discount rate of 10 %, the total NPV of the project becomes 10.63 million £. It is clear that such an investment would be profitable to the operator at Wytch Farm.

4.3 Huabei Oilfield, China

Project stage: Pilot test
Energy type: Electricity and Heat (CHP)
Nominal power: 410 kW of electricity
Reference: **(Hu et al. 2012)**

The Huabei Oilfield experiment is one of the most important co-production tests performed so far. Performed at the LB reservoir at the Huabei Oilfield, it used an ORC with a binary screw expander and a nominal power output of 400 kW, and generated combined heat and power (CHP). After generating electricity, the exiting hot water was used to heat the crude oil. The study focused on increasing the total production of single wells since oil fields generally have lower flow rates than geothermal fields. The effects of increasing the flow rate on both the oil production rate and the water cut were measured as well. Operating at higher flow rates is what enabled the Huabei field experiment to use a higher nominal power generator than other similar experiments.

The LB reservoir has a geothermal gradient of 3.5 °C/100m. The formation temperature has an average of about 120 °C. It's a naturally fractured carbonate reservoir. Production initiated in 1978 and water injection started four months after initial production. The water cut was almost 98 % in 2011. Both the produced fluid volume by well and the number of active wells had decreased sharply over the years.

The test sought to increase the total volume of fluids produced. This is essential to reach higher outputs of electricity. After a successful numerical simulation, three producing and one reinjection well were chosen for a pilot test. The aim was to study how much the reinjection and production rates can be increased, and whether it had any adverse effects on the well head temperature, the water cut, and the oil production.

The result of the pilot test was an increase in the well head temperature until the flow reached 400 t/day, after which increasing the flow only had a small effect on the well head temperature.

Well	Total Flow (t/day)		Well Head Temperature (°C)	
	Before	After	Before	After
#1	54.2	727	54	115
#2	-	1385	-	114
#3	49.1	821.6	77	110

Table 8: The change in well head temperature after increasing the production rate (well #2 has no before data since it had been previously shut down) **(Hu et al. 2012)**

The oil production rate also increased as a result of increasing the total fluid production, accompanied by a slight increase in the water cut.

Well	Total Flow (t/day)		Oil Flow (t/day)		Water Fraction (%)	
	Before	After	Before	After	Before	After
#1	54.2	727	1.4	16.5	97.4	97.7
#2	-	1385	-	12.2	-	98.7
#3	49.1	821.6	1.6	15.1	96.8	98.2

Table 9: The change in oil flow and water fraction after increasing the production rate (well #2 has no before data since it had been previously shut down) **(Hu et al. 2012)**

The producing unit was a binary screw expander of nominal power 400 kW. Production started in April 2011 and the produced electricity was fed into the grid. Heating water entered at 2880 m^3/d and 110 °C, and left the heat exchanger at 85-90 °C. In total the water production from 8 producing wells was used. R123 was used as working fluid. The cooling fluid was water which entered the condenser at 21.1 °C and left at 35.8 °C.

During 2880 hours of operation 310 MWh of energy was produced, equivalent to an average net power output of 107.6 kW. Due to enhancing the production rate, 2902 t of additional oil were obtained at the LB reservoir in 6 months of operation. The exiting heating water was also used to the crude oil on site before it was transported. Thus 10 furnaces were made redundant, saving 2000 t of fuel and 6000 t of CO_2 emissions.

Looking into the future, the geothermal unit could be operated at design conditions with a 310 kW net power output (an equivalent of 2.7 GWh per year), while simultaneously increasing the oil production and mitigating heating costs. The combination of a higher income due to a higher oil output, a lower energy consumption, lower heating consumption, and an additional income by selling energy to the grid, can increase the profitability of oil projects. For marginal producers this could mean an extended lifetime of existing wells and a much welcomed additional profit.

4.4 Rocky Mountains Oil Testing Facility

Project stage: Pilot test
Energy type: Electricity only
Nominal power: 250 kW
Reference: **(Johnson et al. 2011)**

The RMOTC (Rocky Mountains Oil Testing Facility) is a U.S. DOE funded testing facility in the state of Wyoming. It is used by state agencies, universities, and the private sector to test new technological solutions. Amongst others, studies on oil recovery, drilling, and renewable energy have used the site.

The GTP (Geothermal Technologies Program), and the NREL (National Renewable Energy Lab) collaborated with the RMOTC to test the idea of co-producing power from waste streams. The first installed unit was an air-cooled Ormat ORC. It was set up at the Teapot Dome Oil Field and brought online on September 2008. It was run for a first phase until February 2009. Later, adjustments were made and it was brought online again in September of the same year.

During both phases the unit had an availability of 97 % excluding down time caused by field issues. The flowrate, inlet and outlet temperature, ambient temperature, and power output were measured until November 2010.

	Phase 1	**Phase 2**
Period	Sep. 2008-Feb. 2009	Sep. 2009-Nov. 2010
Total water volume (bbl)	3.05 million	7.86 million
Avg. gross power output (kW)	196	210
Avg. net power output (kW)	171	185
Overall power output (MWh)	586	1332

Table 10: Co-produced power output **(Johnson et al. 2011)**

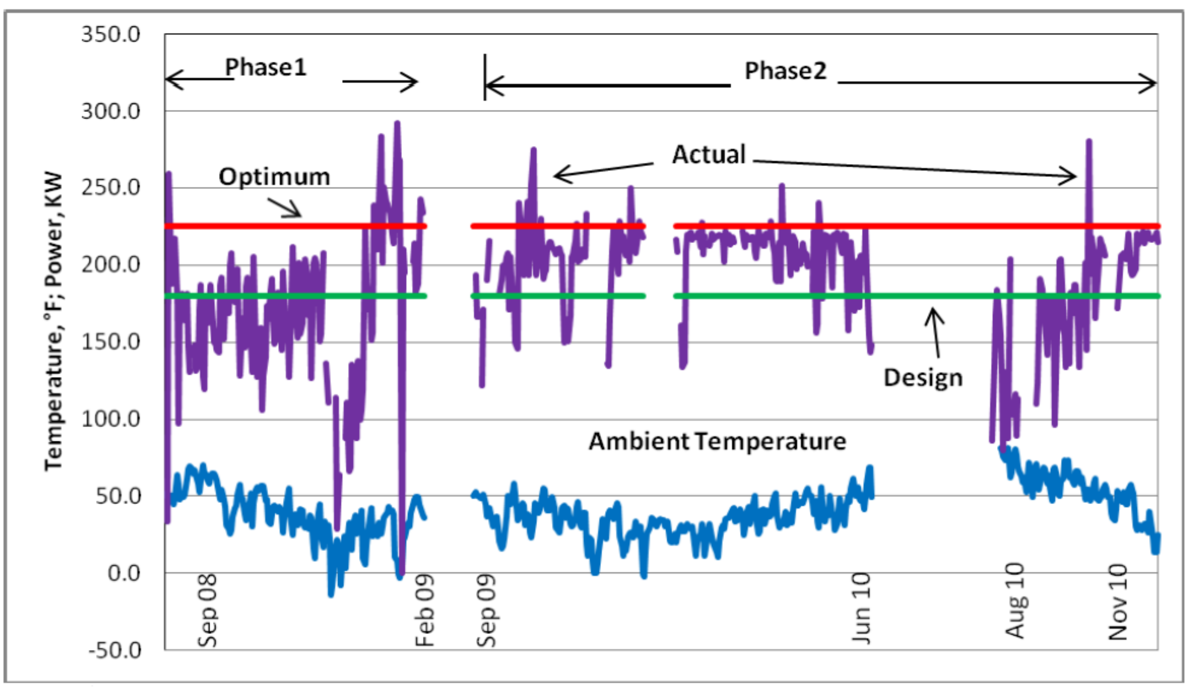

Figure 17: Net power output (in purple) and ambient temperature (in blue) over the test duration **(Johnson et al. 2011)**

4.5 Laurel, Mississippi

Project stage: Pilot test
Energy type: Electricity only
Designed net power: 30-65 kW
Actual net power produced: 19 kW
Reference: **(ElectraTherm, 2012)**

The Green Machine is an ORC power plant built by US company ElectraTherm. It is designed to generate electricity using a hot water source in the range between 190 °F and 240 °F. Through one of its distributors, ElectraTherm teamed up with the Southern Methodist University to find oil and gas wells with water flow and water temperature characteristics suitable to the Green Machine's functioning. The idea was to cooperate with a producer to test the feasibility of co-production.

It was decided that the well operated by Denbury Resources in Laurel Mississippi would be the best candidate for a testing phase. At 4000 bwpd the well has a water cut of 98 % and uses an ESP to pump up the produced fluids. It was decided that using the produced energy on-site would be more beneficial than selling it to the grid (Saving 0.098 $/kWh vs selling at 0.044 $/kWh).

Water is separated from the produced oil before entering a heat exchanger to increase the ORC's working fluid's temperature. The Green Machine uses a twin screw expander with relatively low rotational speed. This makes it possible to process wet vapor through the expander. This allows the process to remain functional even at lower geothermal fluid temperatures. The module was also designed to be put online as quick as possible. It had small dimensions of 7.5 x 8 x 7 feet and was mounted on a trailer with most components pre-installed. Once on-site, it was commissioned in under 50 hours and ready to work.

4.5.1 Results

The Green Machine was run for a total of 1136 hours at the Laurel field. The flow (120 gpm) and low temperatures (204 °F) put the testing site at the lower part of the unit's design interval. The condensing solution was selected from the inventory and not specifically designed for the field since it was only for testing purposes. It proved sub-optimal for dealing with high ambient temperatures during the summer in Mississippi and its performance can be improved in future projects. Because of the earlier reasons, the unit was able to produce an average of 19 kW instead of the 30-65 kW it was designed for. This production was still able to cover 20 % of the down-hole pump's energy needs.

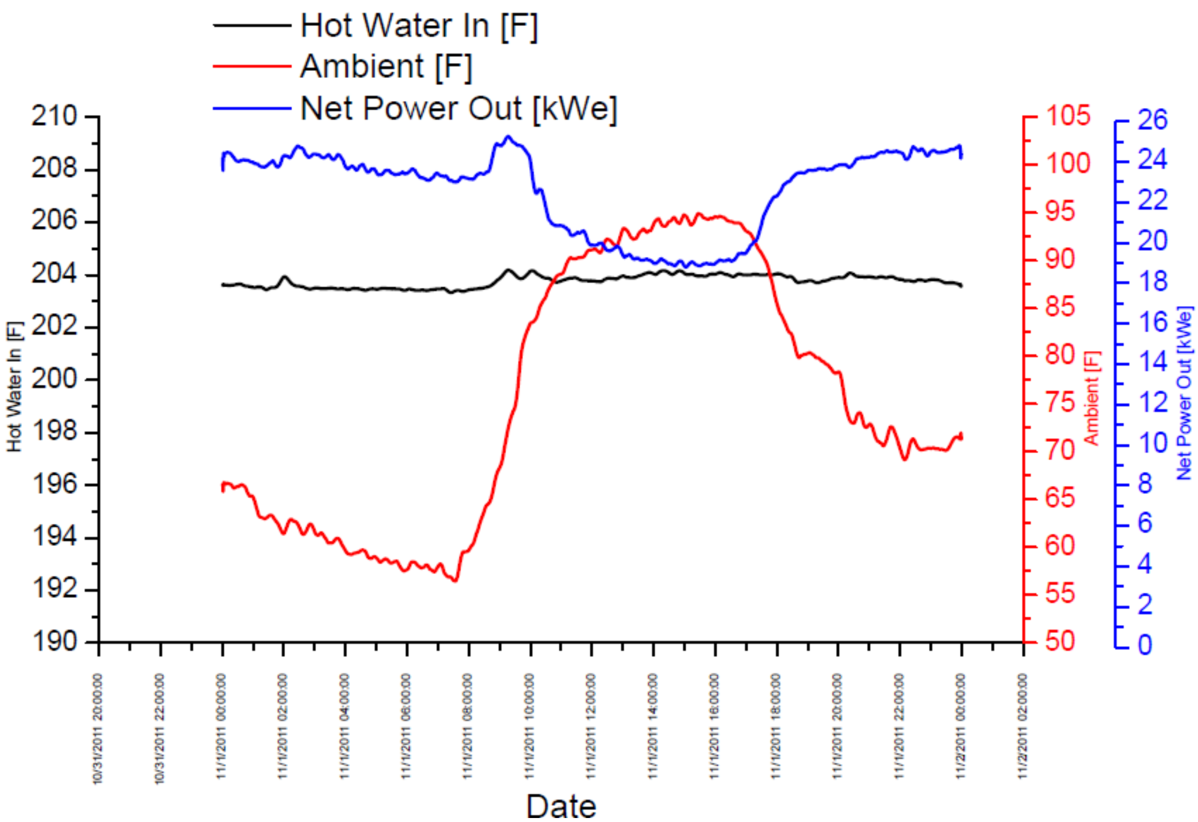

Figure 18: Net power output (blue); Brine inlet temperature (black); Ambient temperature (red) (kW_e stands for kilowatt electric and is equivalent to kW) **(ElectraTherm, 2012)**

CHAPTER 5: ABANDONED AND SPENT WELLS

Abandoned or spent oil wells can be converted to purely geothermal ones provided the subsurface temperature is high enough to permit geothermal exploitation. Some differences exist when compared to the co-production scenario. First, the produced electricity can't be consumed on site as the oil well is no longer active. Therefore proximity to end consumers and an infrastructure to sell the electricity into the grid are essential.

On the other hand, an advantage for abandoned wells is the implementation of a closed single cycle ORC operation compared to the dual cycle ORC used for co-production. The difference here is that there is no need to produce water to heat the working fluid. Instead, the well is closed and the ORC's working fluid is injected down the annular space before being produced through the tubing.

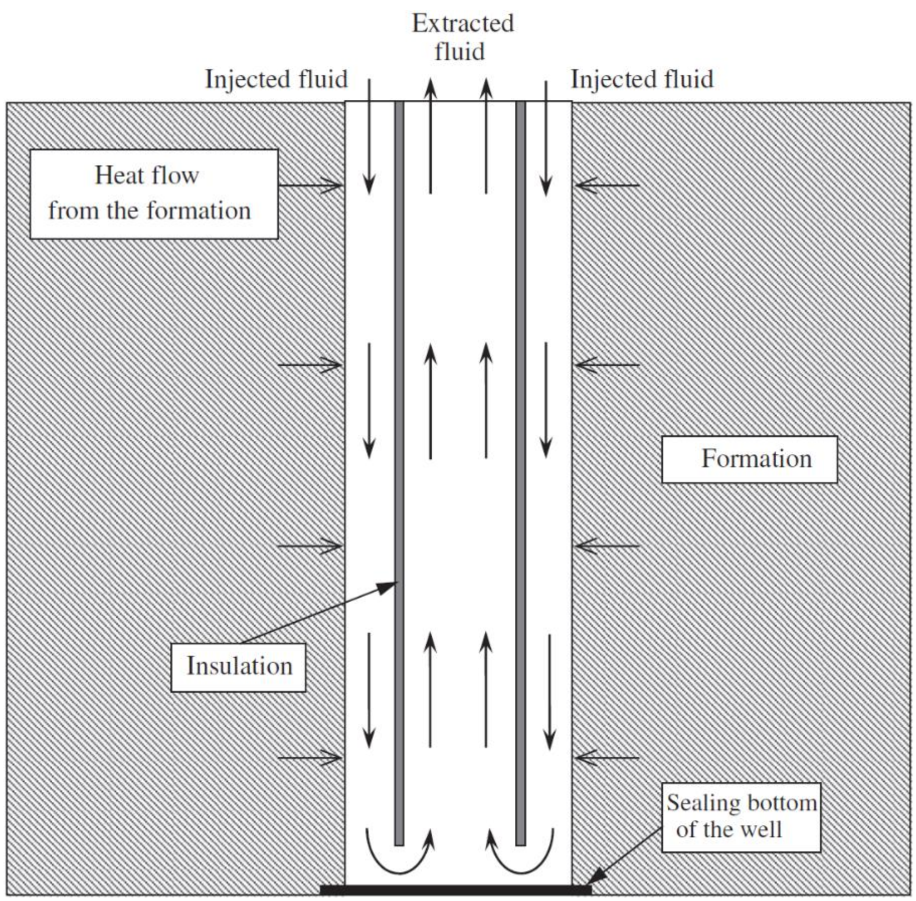

Figure 19: Heat extraction through a sealed abandoned well
(Cheng et al., 2014)

The well along with the formation act as a heat exchanger where the formation acts as the heating fluid. When injected down the annulus, the working fluid exchanges heat with the hotter formation until it reaches the needed temperature, and is brought back up to surface through the tube. Proper insulation between the annulus and tube is essential, otherwise the heated working fluid traveling up the tube will lose heat to the relatively cooler fluid coming down the annulus. Single cycles are more efficient from a thermodynamic point of view.

Other operational advantages exist as well. First, water is no longer produced, so re-injection and/or water treatment are no longer needed and their costs eliminated. Second, corrosion is better controlled. The only fluid circulating in the system is the working fluid of known and controllable properties. Potentially highly corrosive reservoir fluids are no longer an issue.

As previously discussed in chapter 2, the oil producer will save decommissioning costs, while the new energy producer saves on exploration, drilling, and other upfront costs. Therefore, several studies have been made in order to size up the potential for geothermal energy in different regions around the world. This chapter will discuss these findings.

For the studies presented in this chapter, all of the data, images, and tables presented are either taken directly from, or based on information found in a single study. “Geothermal Energy in Texas” is based on **(Airhart, 2011)**, and “Geothermal Energy in Hungary” is based on **(Tóth, 2016)**. To avoid repeating these references multiple times, they will be listed only once at the beginning of each part.

5.1 Geothermal Energy in Texas

Project stage: Study
Potential: 17000 of 30000 studied wells had temperatures exceeding 100 °C
Reference: **(Airhart, 2011)**

At the beginning of this decade, the interest in geothermal resources re-emerged in the United States. As part of this trend, the US DOE provided research grants of up to 360 million $ in total for several independent projects. Besides areas of established geothermal presence, the DOE looked into the possibility of exploiting the subsurface of new regions.

Bruce Cutright, at the time research associate at the University of Texas, obtained three such grants with a total value 2 million $. The aim was to explore the feasibility of geothermal projects in Texas. Cutright later founded Thermal Energy Partners of which he is the current CEO.

Of the three grants, two were dedicated to collect existing data from research and industry to draw gradient map of subsurface temperatures for the National Geothermal Data System (NGDS). The NGDS is an online collection of data related to geothermal exploration. The collected figures included crucial information like bottomhole temperature and pressure along with geophysical and petrophysical reservoir characteristics. The other grant was intended to study the possible combination of CCS technology (Carbon Capture and Storage) with geothermal. This foresees using CO2 instead of water to extract heat.

The result was a gradient map of the bottomhole temperatures of oil wells all over the state. In 17000 of the mapped wells (57 %), the temperature exceeded 100 °C. With current technology way lower temperatures energies have been sufficient for successful energy production. Three previously discarded areas have been distinguished as promising: Crocket County, Robertson County, and the Anadarko Basin shared with the State of Oklahoma (all three regions are indicated on the map in Fig. 20, see next page).

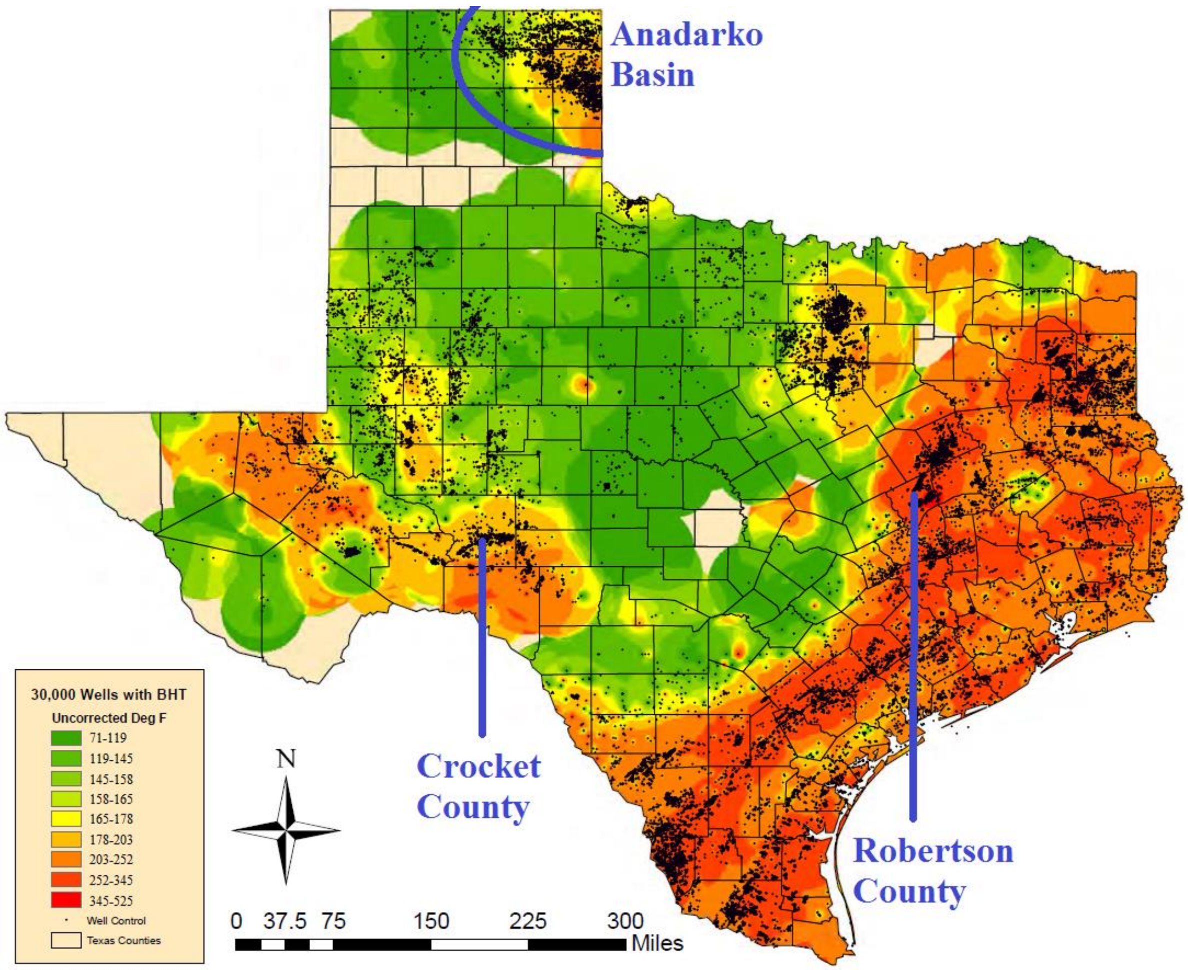

Figure 20: Bottomhole Temperature gradient Map of 30,000 Texas wells **(Airhart, 2011)**

It is important to note that temperature alone is not enough to determine the geothermal producibility of a well. The petrophysical characteristics of the subsurface are of crucial importance and should be taken into account before considering any enterprise.

5.2 Geothermal Energy in Hungary

Project stage: Study
Potential: 168 abandoned wells with promising characterisitics, 131 wells with temperatures exceeding 90 °C
Reference: **(Tóth, 2016)**

5.2.1 Introduction

Developing renewable resources is at the core of the Hungarian government's energy policy. So far the country heavily relies on fossil fuels as their main source of energy, which make up 81.9 % of the used energy, of which 70 % is imported. The dependence on foreign countries is the highest for natural gas. The local reserves of oil and gas would be exhausted in 23 and 21 years respectively at current production rates, which would further increase the dependence on imports.

Therefore, the so called "National Energy Strategy Plan 2030" of Hungary insists on expanding the use of nuclear and renewable energies to lower the dependency on foreign imports and secure national energy security. The Geothermal Atlas of Hungary, published by the Hungarian Energy and Public Utility Regulatory Authority, describes the geothermal potential in each one of Hungary's counties. It details the prevalent geology, the heat flow, geothermal gradients, as well as existing thermal wells. In addition to that it explores the abandoned oil and gas wells that have good characteristics for geothermal exploitation.

5.2.2 Geothermal Characteristics of Hungary

In 2014, geothermal energy made up 0.99 % of energy consumption in Hungary. Of the present geothermal wells, 80 % produce water from porous sandstone layers. At a depth between 1500m and 2000m, these porous reservoirs have effective porosities in the range of 25 % to 30 %, and permeabilities going from 500 mD to 1000 mD. The other 20 % produce water from karstic rock. Karstic reservoirs are fissurized systems of carbonate rocks. Karstified limestone from the Triassic period has the best storage properties and is found at deeper depths than the porous reservoirs. Figure 21 on the following page shows the distribution of karstic and porous aquifers on the Hungarian map.

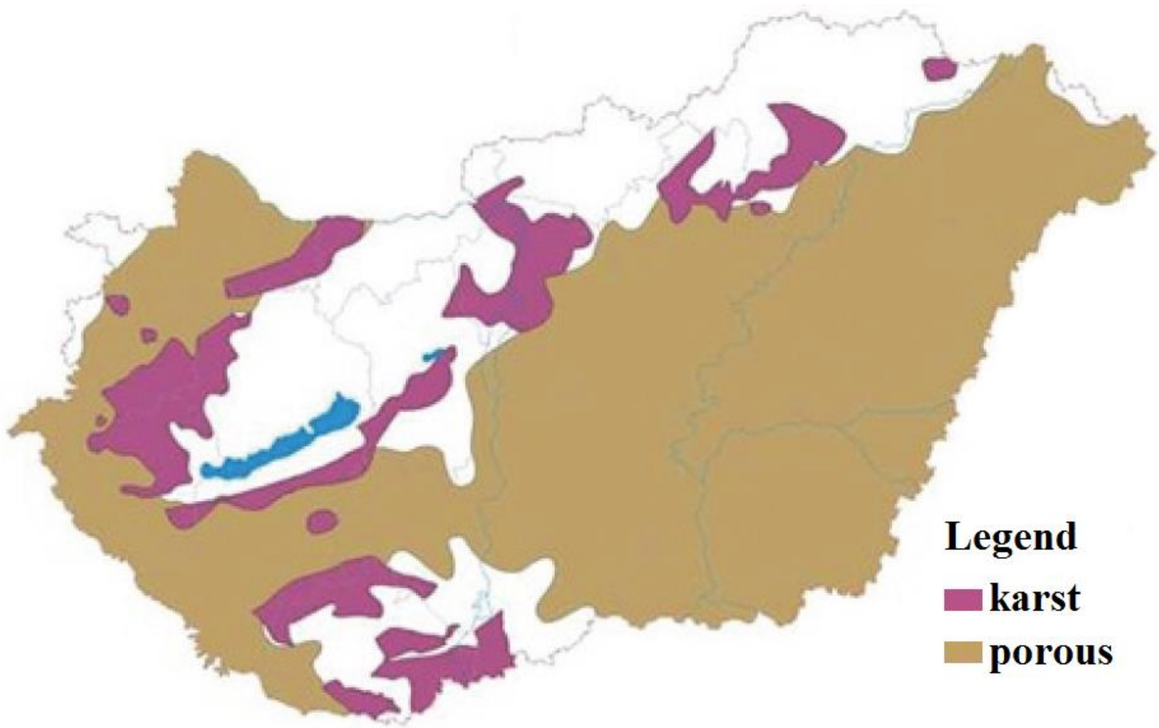

Figure 21: Distribution of Karstic and Porous Reservoirs in Hungary **(Tóth, 2016)**

Compared to both the world and Europe, Hungary has great properties for geothermal exploitation. The heat flow density is in the 90-100 mW/m^2 range. This compares well against the world average of 60 mW/m^2 and an even lower average for continental shields. The geothermal gradient is between 42 °C/km and 45 °C/km. In the city of Táska this gradient reaches 100 °C/km, meaning temperatures of 100 °C can be met at a depth of merely 1000 m.

5.2.3 <u>Findings</u>

The study displayed depth isotherms of 30 °C, 50 °C, 60 °C, 70 °C, and 90 °C for different uses of heat. For the scope of this thesis, we are concerned only with wells whose temperatures are equal to or above 90 °C. The other wells can be useful to generate heat for district heating, agricultural, and industrial use. They are however impractical for the production of electricity and thus not relevant to this work.

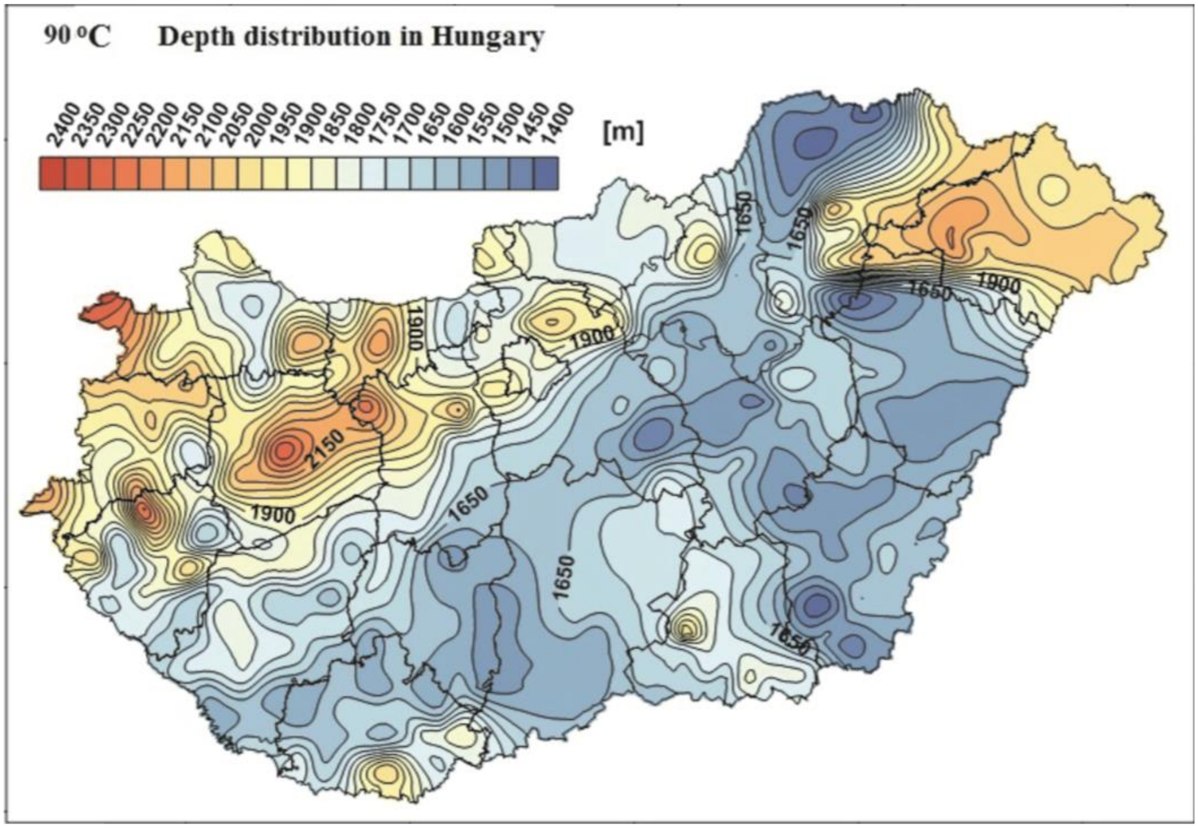

Figure 22: Depth of the 90°C Isotherm in Hungary **(Tóth, 2016)**

Hungary is made up of 19 counties plus the capital Budapest. Budapest was excluded and only the counties were part of this study. In these counties 1537 thermal wells already exist. Most of them are used for Spas, some others for agricultural and industrial purposes. Only a small fraction of the existing thermal wells reached temperatures of 90 °C or higher. However, 168 abandoned hydrocarbon wells were found to have good characteristics for a potential use as a source of geothermal energy. Out of these, 131 were close to or even deeper than the 90 °C isotherm. This is about 78 % of the 168 wells, with one particular well in the Csongrad county having a bottomhole temperature of 250 °C.

The full study was released in 2016. So far, no further comment has been made on whether or not any of these wells were to be studied more closely in the coming future. A more precise breakdown of the wells by county is presented in table 11.

County Name	Number of existing thermal wells	Abandoned Oil and Gas Wells with good Geothermal Potential	Potential Geothermal Wells with Bottomhole Temperature>90°C
Bács Kiskun	80	27	17
Baranya	66	2	1
Békés	230	19	18
Borsod-Abaúj-Zemplén	51	1	0
Csongrád	282	9	9
Fejér	21	0	0
Györ-Moson-Sopron	25	8	4
Hajdú-Bihar	111	30	27
Heves	64	2	2
Jász-Nagykun-Szolnok	216	13	12
Komárom-Esztergom	9	0	0
Nógrád	5	0	0
Pest	85	3	1
Somogy	91	20	17
Szabolcs-Szatmár-Bereg	38	2	1
Tolna	38	0	0
Vas	46	4	2
Veszprém	11	1	0
Zala	68	27	20
Total	**1537**	**168**	**131**

Table 11: Distribution of Wells in Hungary by Counties **(Tóth, 2016)**

CHAPTER 6: MISCELLANEOUS

The studies presented in this chapter were selected apart because while being relevant to the study, don't necessarily fit the previous chapters.

For both studies, all of the data, images, and tables presented are either taken directly from, or based on information found in two studies for each. "Florida Canyon Mine, Nevada" is based on **(NBMG, 2014)** and **(ElectraTherm, 2015)**, while "Pleasant Bayou, Texas" is based on **(John et al., 1998)** and **(Akhmadullin, 2017)**. To avoid repeating these reference multiple times, they will be listed only once at the beginning of each part.

6.1 Florida Canyon Mine, Nevada

Project stage: Pilot test (2009-2010). Full implementation (2012-today)
Energy type: Electricity only
Peculiarity: Generated from water co-produced with metals (Not an oil well)
Nominal power: 50 kW (Pilot Test). 75 kW (after 2012)
References: **(ElectraTherm, 2015)** and **(NBMG, 2014)**

The Florida Canyon Mine is located in Nevada, USA. It produces gold, silver and mercury. The wells at the Florida Canyon produce a brine with temperatures exceeding 100 °C from ca. 175 m of depth. These fluids are then used for a heap leaching process to extract the metals. Even though not an oil well, it remains an interesting case in which electricity was generated using co-produced fluids.

In 2009 and 2010 US company ElectraTherm ran its "Green Machine" at the Florida Canyon Gold Mine as a testing phase. It had a nominal output of 50 kW. During the 1000 hours of running time it covered about 5 % of the electricity consumption at the site.

As a result, the U.S. DOE granted ElectraTherm an initial R&D fund of a little less than a million dollars. Additional funds were granted later to optimize the "Green Machine" for brine applications. The updated version, called Power+, is a 75 kW plant. It was commissioned in 2012 and is operating at 150 gpm of brine with co-produced fluids' temperatures ranging between 107 °C and 110 °C.

6.2 Pleasant Bayou, Texas

Energy Type: Electricity
Peculiarity: Abandoned well. It produces chemical, geothermal and hydraulic energy.
Nominal power: 3.12 MW
References: **(Akhmadullin, 2017)**, **(Campbell, 2006)** and **(John et al., 1998)**

The Pleasant Bayou is a depleted field that was transformed into an Enhanced Geothermal System (EGS). Unlike the previous examples it doesn't exclusively rely on geothermal energy to generate electricity. Instead it makes simultaneous use of three types of energy: Chemical, Thermal, and hydraulic.

Water is produced at a rate of 20,000 bwpd with a high well head pressure. The water reaches a temperature of 144 °C. Gases are also dissolved in the brine, methane makes up 85 % (mol%) of these gases.

The dissolved hydrocarbons are immediately burnt on site. The chemical energy released by this combustion accounts for 49 % of the produced electricity. The high flow rate and wellhead pressure of the water generates hydraulic energy by driving turbines. This makes up 14 % of the produced electricity. The remaining 37 % are generated with an ORC which uses the geothermal heat stored in the brine. The system has a nominal power of 3,130 kW.

CHAPTER 7: CONCLUSION

7.1 Producing wells

Co-production systems have shown to be economical in multiple case studies and pilot tests. The two most important factors for a project's success are a high temperature of the produced fluids, and more importantly, a high water flow rate.

Using the generated electricity on-site is usually the most profitable choice. If government policies are in place to support renewable energy production are in place, the produced electricity can be sold at a premium price to the grid. In this case, selling the electricity become the more profitable choice. The Wytch Farm study highlighted such a case.

Co-Production is better suited for smaller producers rather than multinational companies. The operation of a power plant in parallel to an oil field might prove disagreeable for some producers. Especially the big oil companies who make huge profits off their oil production might not consider a profit in the order of a few million dollars to be worth the associated risks. Furthermore, the geothermal production might be an annoyance that comes in the way of day to day activities on an oil field. However in the case of smaller companies who often produce marginal fields with relatively smaller profits, the added profit and the extension of a field's lifetime can become a significant bonus to their oil operations. In fact, most of the applications, pilot tests, and studies performed so far were done on fields operated by smaller oil companies and not the big multinational corporations.

One obstacle facing a larger research into this subject is the difficulty with which data of operating oilfields is accessible. Oftentimes producers are reluctant to share information related to their operations even when they are cooperating with researchers. Financial incentives from the government could make co-production systems more attractive to the oil producer and bridge the gap for better cooperation between industry and academic research.

7.2 Abandoned and spent wells:

The case of abandoned wells is very attractive especially for companies in the geothermal sector. Regular geothermal projects are very CAPEX intensive. Most of the capital costs of the typical project go to the exploration and drilling phases which would no longer be needed if geothermal companies had access to hundreds of already drilled wells with all the relevant data needed to decide whether or not a specific field is useful for geothermal exploitation.

Abandoned wells don't have the possibility to consume the electricity on site because they have stopped producing oil. Selling the produced energy back to the grid is the only option available. Because of this, the proximity to possible end users and a preferably pre-existing electric infrastructure are very important factors for selecting which wells to convert for energy production.

So far only a few projects have been executed, but government funded research has shown the large potential this industry can have in the future. A better legal situation would largely benefit advancements in this domain. So far, companies have to apply for licenses to explore a field either for hydrocarbons or for geothermal energy. The possibility to apply for a license that includes both types of energies would largely benefit these exploration activities. In this way, a company could drill a field looking for oil, and if the field was found to be unpromising for oil production but showcased good properties for geothermal operations, the exploration wells can be immediately repurposed and kept in use without having to apply for new licenses. A proposition for a similar law has been made in the Netherlands.

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