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Geothermal Energy From Repurposed Oil And Gas Wells In Western North Dakota

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GEOTHERMAL ENERGY FROM REPURPOSED OIL AND GAS WELLS IN WESTERN NORTH DAKOTA

by

Sidike Abudureyimu

Bachelor of Science, Central South University, China, 2010

A Thesis
Submitted to the Graduate Faculty
Of the
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for the degree of
Master of Science in Geological Engineering

Grand Forks, North Dakota
May
2020

This thesis, submitted by Sidike Abudureyimu in partial fulfillment of the requirements for the Degree of Master of Science in Geological Engineering from the University of North Dakota, has been read by the Faculty Advisory Committee under whom the work has been done and is hereby approved.

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Department	Harold Hamm School of Geology & Geological Engineering
Degree	Master of Science

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Sidike Abudureyimu
May 5, 2020

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ABSTRACT

Repurposing directional drilled Bakken oil wells to utilize ORC technology for electrical power generation is uneconomical for coproduced fluid in current active oil and gas fields in the Williston Basin. Geothermal power generation requires three crucial factors: heat source, sufficient and sustainable flow rate, and efficient binary technology. This feasibility study focuses on evaluating geothermal co-production fluid for current Sanish, Parshall, and Banks Bakken multi-wells pads. The wells lie within a 2.5-mile (4 km) radius within each field and extend to depths of 9,900 to 11,000 ft. (3 - 3.5 km). Within a 2.5-mile radius area, there are several multi-well pads. Geological parameters were evaluated for each well to determine the fluid flow rate, heat transport, and formation temperatures. The study areas contain the highest number of horizontally drilled wells in the Bakken Formation. The oil fields produce fluid from a low permeability range of 0.05 to 0.2 millidarcies (mD), porosity between 0 and 10%, and rocks at a low flow rate of 0.4 to 0.6 liters/second (l/s). Thermal models of heat loss from the vertical sections of the wells show that the flow rate is too slow to yield adequate temperatures for electrical power production. However, a new alternative approach could produce sufficient temperatures and flow rates for hundreds of MW (Megawatts) of power. That approach would be to drill horizontal open-hole water wells into the deeper Deadwood and Red River Formations. These more permeable formations can yield a significant amount of fluid at approximately 50 l/s or higher at temperatures greater than 150 °C.

INTRODUCTION

Geothermal energy is the thermal energy from Earth's interior, and it has a variety of applications, including space heating and cooling, district heating, industrial heat processes, and electrical power generation. The project objective is to assess the economic feasibility of the current active Bakken oil fields' potential capability of generating electricity through binary technology. The Bakken Formation fluid can be utilized as a geothermal resource because its fluid has a low-temperature range of a 100 to 150°C. The Bakken coproduced fluid can be used in existing oil field infrastructure with binary organic Rankine cycle (ORC) technology. Binary ORC power plants are well known and the most common technology for utilizing low-temperature geothermal resources for electricity generation. Nevertheless, steam turbine technology is broadly applied for high-temperature resources greater than 220°C.

The high-temperature resources are suitable for commercialized electricity production with conventional steam turbine generators (Barbier, 1997). Geothermal power generation includes several well-established technologies, such as dry steam plants, flash steam systems, binary technology, and enhanced geothermal systems (EGS) (Tomasini-Montenegro et al., 2016). However, the Bakken Formation's available bottom-hole temperatures typically range from 100 °C to 120 °C in western North Dakota (ND) and require binary technology to generate power (Crowell *et al.*, 2013). Moreover, the Bakken oil field's coproduced fluid is considered as the potential convertible geothermal energy.

The continuous availability and reliability of geothermal energy make geothermal resources more attractive for the power industry in comparison to other renewable energy sources, such as wind and solar energy (Michaelides, 2015). Geothermal energy has the advantages of reliable, baseload, and sustainable energy, whereas wind and solar depend on the weather. Additionally, geothermal energy is stored in the fluid in the Bakken oil fields. The coproduced fluids are primarily water and natural gas.

The coproduced water volume from oil and gas operations in the Bakken Formation in ND is about 6 x 10^9 liters per year (North Dakota Industrial Commission database -NDIC, 2018). The fluid temperature of the Bakken formation at 3,225 m depth is about 130 ºC (McDonald *et al.*, 2015; Williams *et al.*, 2016; Nordeng, 2020). This suggests that the coproduced Bakken water constitutes a potential energy resource. Thus, in theory, existing oil fields are producing a sufficient amount of water for geothermal power generation using binary technology. The geothermal energy could be a new industry in western ND (Gosnold *et al.*, 2017). Although the Bakken oil fields are producing a large volume of water, gathering sufficient volume of fluid to justify the construction of power plants will be a challenging task. While there are more than 12,000 producing Bakken wells in ND oil fields, there is also an increasing number of plugged and abandoned oil and gas wells, including more than 7,000 dry wells that could be redeveloped for geothermal use (Gosnold *et al.*, 2017). Historically, many oil wells were drilled and completed vertically for conventional vertical oil extraction. Now, the oil companies are drilling more wells horizontally, which can spread in the Williston Basin. With the increased contact surface in the reservoir from horizontal drillings, the development of multi-well pads in the most directional drilled fields - Sanish, Parshall, and Banks Bakken Fields – have the possibility of providing opportunities for accessing sufficient fluid temperature and flow rate.

In order to properly estimate stored energy in these study fields - Sanish, Parshall, and Banks Bakken Fields - a heat flow map, heat flow data, thermal conductivity data, and climate data obtained from conventional heat flow measurements, corrected bottom-hole temperatures (BHT) and monthly production data are considered. (Gosnold *et al.*, 2010; 2012; McDonald *et al.*, 2015; Williams *et al.*, 2016; NDIC, 2019; Nordeng, 2020). These data were used to select suitable and efficient ORC systems, which are Climeon 150 kW Heat Power System (referred to as Climeon), Calnetix 125 MT Thermapower® ORC unit (referred to as Calnetix), and ENOGIA ORC system (referred to as ENO). The most crucial step of this study was conducting the economic feasibility analysis. This analysis ensures that the selected ORC power generation system has a high degree of success and commercial capability of the project.

A significant and globally important outcome of this project would be a demonstration of the potential for geothermal power to reduce greenhouse gas emissions in active oil-producing fields in western ND. The U. S. Energy Information Administration (EIA) statistic in 2017, states that the North Dakota Carbon Dioxide Emission from fossil fuel consumption was 56 million metric tons. Yet the potential success of geothermal power generation would not only benefit the local community and oil industry, but it would also help to reduce emissions.

STUDY AREA

The primary study areas are in the most drilled and developed oil fields in the Williston Basin ND. The Williston Basin is a large ellipsoidal-shaped intracratonic basin extending over 933,000 km^2 (36,023 sq. mi), which covers parts of ND, Montana, Saskatchewan, and Manitoba (Figure 1). Initial subsidence began in the Ordovician and continued into the late Tertiary. Thus the basin has a complete stratigraphic record of the Phanerozoic Era (Gosnold *et al.*, 2010). The basin includes more than 54 distinct formations, 20 of which produce oil and water having temperatures in the range of low-to-intermediate geothermal resources from 65°C to 150°C (Gosnold *et al.*, 2010) (Figure 2). Recent oil-producing activity in the basin has focused on the Bakken and Three Forks Formations, which are estimated to contain more than 400 billion stored barrels (bbl.) of oil (Nordeng *et al.*, 2010).

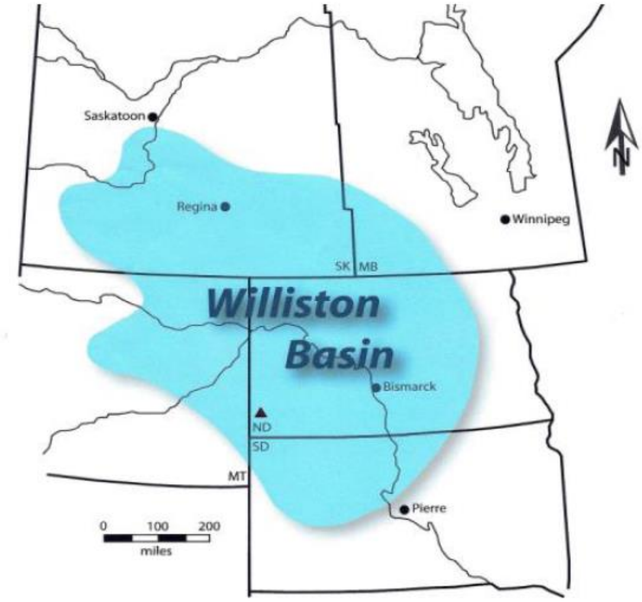


Figure 1. Location of the Williston Basin (Adapted from Gosnold *et al.*, 2010)

This study primarily focuses on Sanish, Parshall, and Banks Bakken Formation producing fields that are in Mountrail and McKenzie county, ND (Figure 3). Horizontal drilling has been the most used practice in the Sanish, Parshall, and Banks Bakken oil fields, which covered approximately 536 km^2 (207 sq. mi), 746 km^2 (288 sq. mi) and 282 km^2 (109 sq. mi) in the Williston Basin respectively (Figure 4 - 6). According to the NDIC (2019), the Sanish Bakken Field drilled 651 wells, which produced a fluid average of 3.18 x 10^6 barrels per month. This included 50,571 barrels per day (bar/d) of oil and 42,823 bar/d of water. The temperature in the Bakken Formation is approximately 114°C (Gosnold et al. 2019). The Parshall Bakken Field has 475 wells that produced a fluid average of 1.81 x 10^6 barrels per month. Which included 32,229 bar/d of oil and 27,325 bar/d of water; the Bakken Formation temperature is approximately 100°C (Gosnold et al. 2019). The Banks Bakken Field has 252 production wells. The Field has produced on average 2.77 x 10^6 barrels per month, which include 42,206 bar/d of crude oil and 48,411 bar/d of water. The Bakken Formation temperature is approximately above 143°C (Gosnold et al., 2019; Nordeng, 2020). The Bakken Formation porosity ranges from 5% - 10% and 0.05 – 0.2 millidarcy (mD) of permeability, which limits fluid production (Pramudito, 2010).

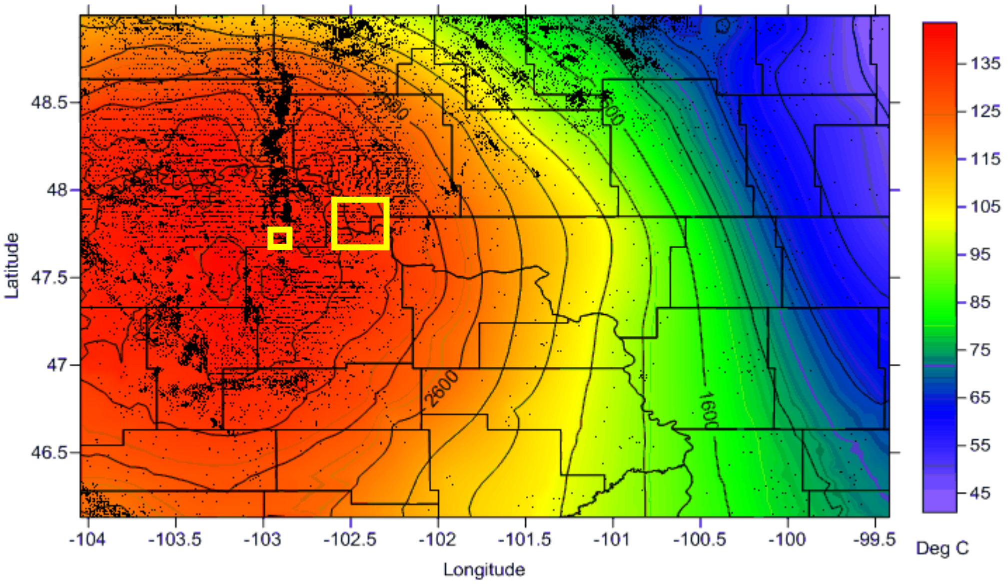


Figure 2. The study areas (yellow areas) temperature and depth contours for the Bakken Formation in Williston basin, North Dakota (Adopted from Gosnold et al., 2015)

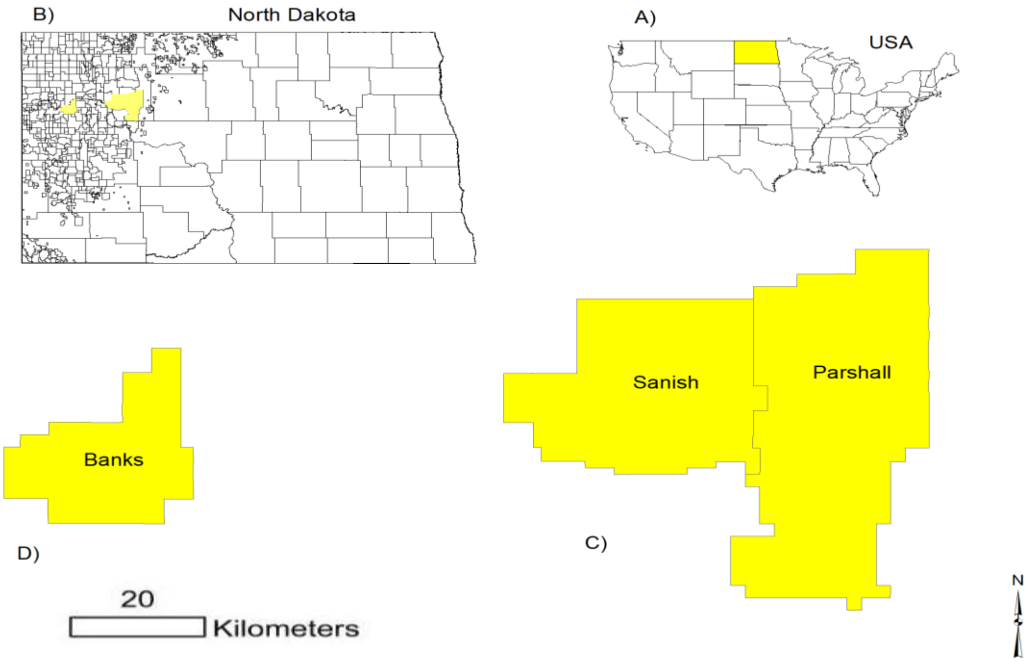


Figure 3. Study oil field location. A) Location of North Dakota (ND) in the USA. B) Location of Sanish, Parshall, and Banks oil fields in ND. C) Sanish and Parshall Fields, D) Banks Field

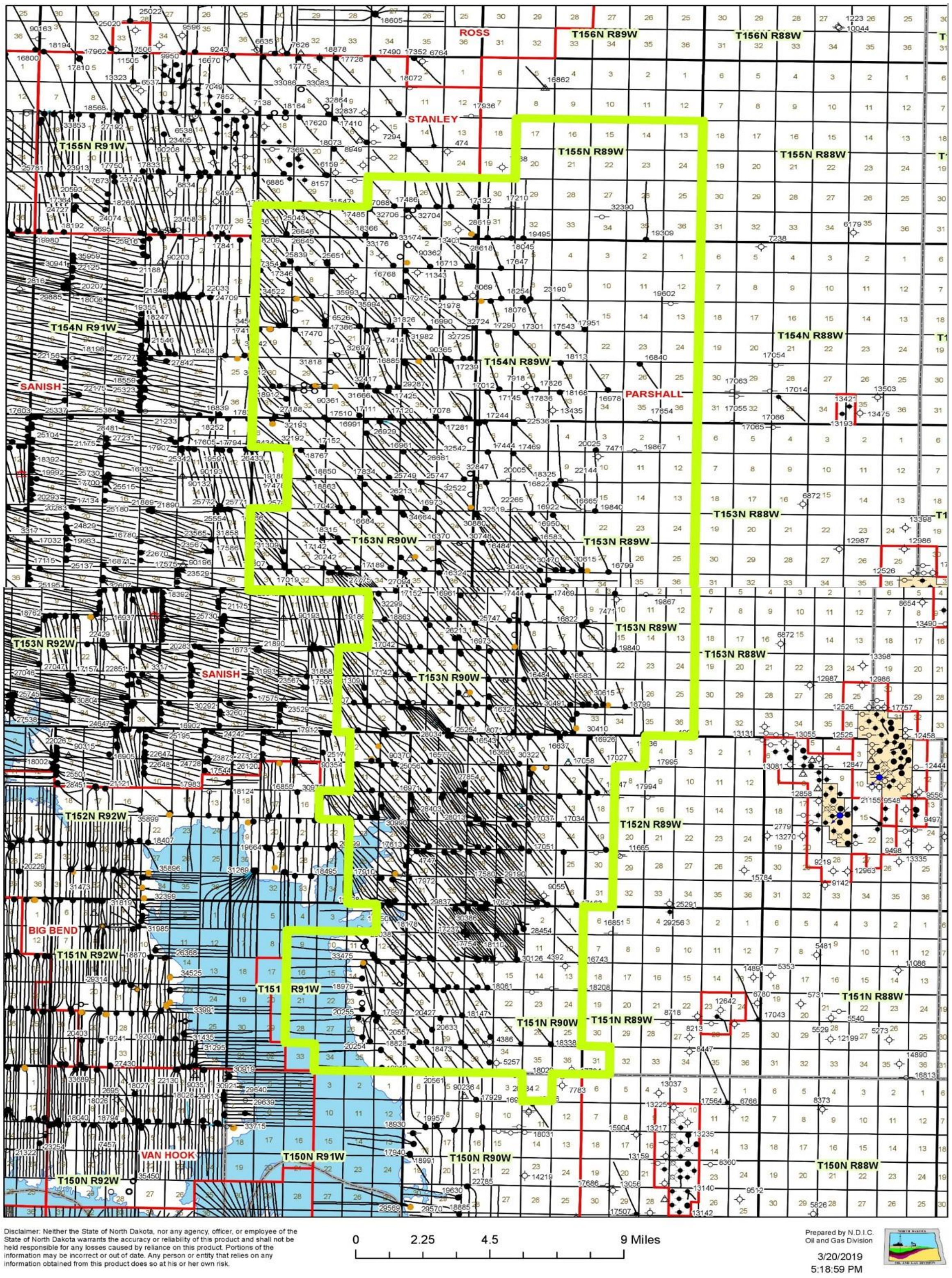


Figure 4. Horizontal laterals depicted as lines are drilled wells in the Parshall Field (NDIC 2019)

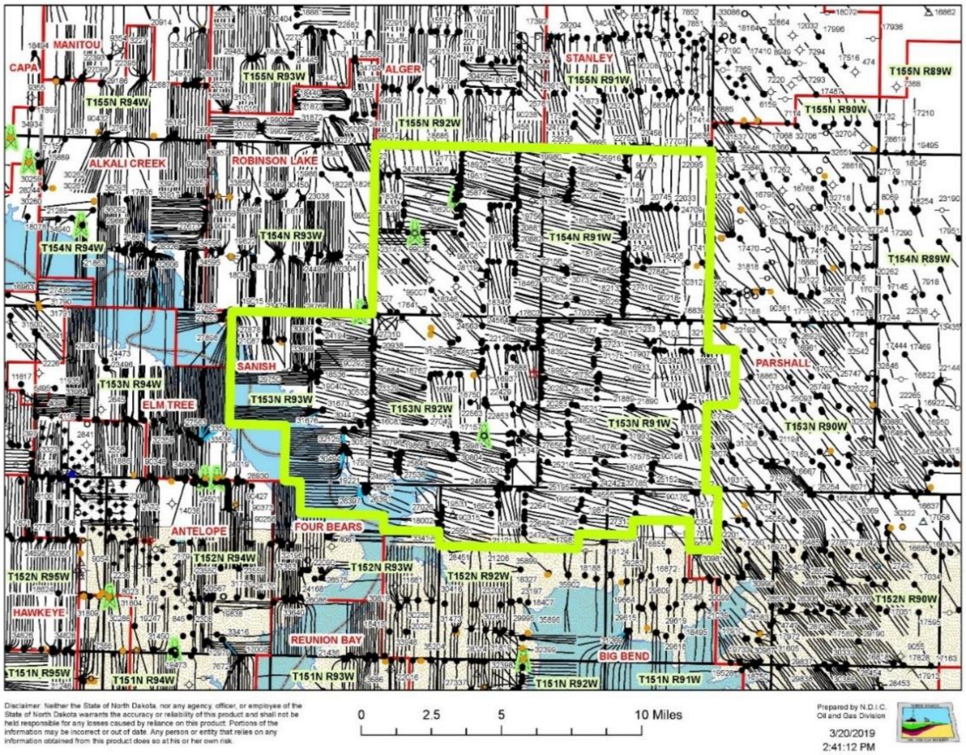


Figure 5. Horizontal laterals depicted as lines are drilled wells in the Sanish Field (NDIC 2019)

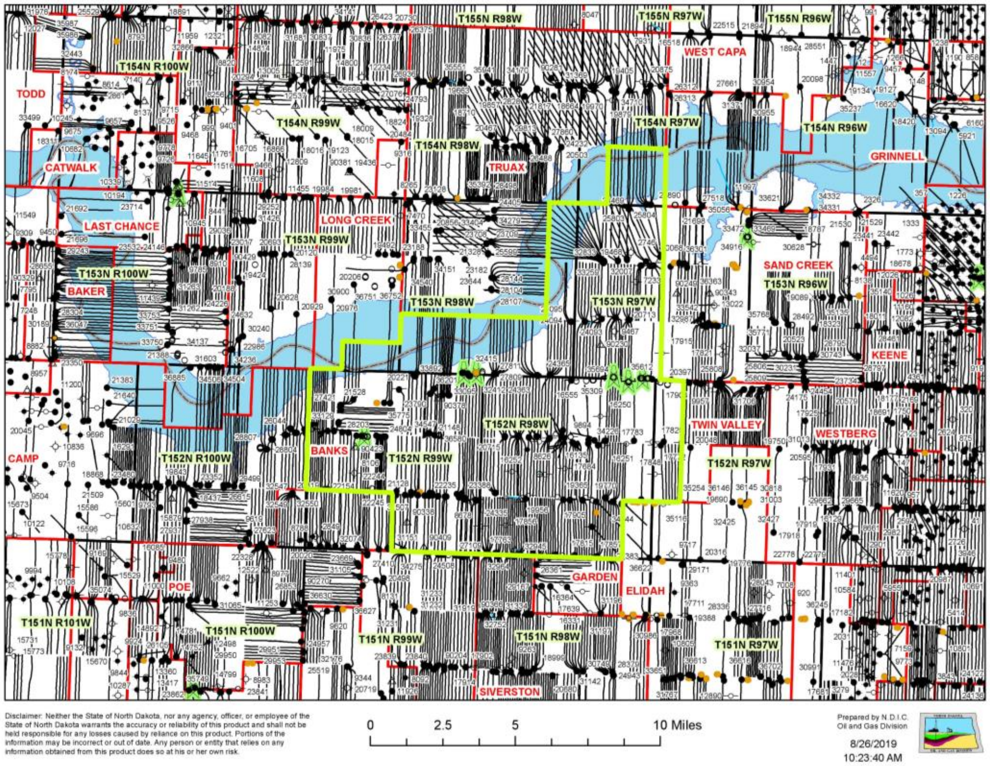


Figure 6. Horizontal laterals depicted as lines are drilled wells in the Banks Field (NDIC 2019)

PREVIOUS STUDY

Gosnold *et al.* (2010) and Crowell *et al.* (2011) determined the Bakken Formation temperatures of the Williston basin in ND using heat flow, lithostratigraphy, thermal conductivity, and BHT. Gosnold *et al*. (1999) analyzed basin geothermics based on crustal average radiogenic heat production, conventional heat flow, and limited BHT data. Crowell *et al*. (2013) also measured thermal conductivities for the basin using the divided bar method. Gosnold *et al*. (2012) used Fourier's law of heat conduction equation (Eq.1). The calculation was used homogenous thermal conductivities and was in a condition of steady-state heat flow. The boundary conditions were 1) heat flow q at the surface was assumed constant, 2) the temperature gradient was $\frac{dT}{dZ}$, and 3) thermal conductivity was λ,

$$q = \frac{dT}{dZ}\lambda \qquad \text{Eq.1}$$

and the temperature at depth was calculated from (Eq.2),

$$T(z) = T_0 + \sum_{i=1}^{n} \frac{qz_i}{\lambda_i} \qquad \text{Eq.2}$$

This equation described as the TSTRAT hereafter where

$T(z)$ = Temperature at depth z (°C)

T_0 = Surface temperature (°C),

q = Heat flow (mWm^{-2})

z_i = Formation thickness (m)

λ_i = Formation thermal conductivity ($Wm^{-1}K^{-1}$)

dT/dZ = Temperature gradient ($K\ km^{-1}$)

In the TSTRAT calculation, heat flow was assumed to be 50 mWm^{-2}, the surface temperature was 7°C, thermal conductivity for shales was between 1.1 and 1.6 $Wm^{-1}K^{-1}$, and the temperature gradient ranged from 39.8 – 45.6 $K\ km^{-1}$. The results of Gosnold *et al.* (2012; 2019) analysis showed that the Bakken Formation temperatures were at a depth of 3.0 km to 3.5 km and ranged from 100 to 143°C. The Bakken Formation temperatures are optimistic and might be high its actual temperature. This thesis used the existence of temperature vs. depth profiles for the basin based on previous studies and evaluated the economics of convertible thermal energy via binary technology. The test case of a geothermal power plant project was conducted in 2016.

In the pilot geothermal power plants project, University of North Dakota – Continental Resources, Inc. (UND – CLR), Gosnold *et al.* (2017) demonstrated electric power generation using binary technology from low to intermediate temperature resources in the Williston Basin. The project site provided access to 98 ºC water flowing at 51 l/s at the Davis Water Injection Plant in Bowman County, ND. The potential gross power output from this project was 250 kW at the cost of $3,400 per kW. The binary system was designed to generate 125 kW. The UND team's analysis of the entire Williston Basin thermal energy yielded 4.0 x 10^{19} Joules (J) by using data on porosity, formation thicknesses, and fluid temperatures. The potential power generation using binary ORC power plants was 1.36 x 10^9 MWh.

The study applied the Department of Energy (U.S. DOE) Cost of Renewable Energy Spreadsheet Tool (CREST) to determine economic analysis that the first-year cost of energy was 7.25 ¢/kWh (Gosnold et al., 2017). The project showed that generating electricity from existing infrastructures in oil fields was technically and economically practicable using ORC systems if there were sufficient flow rate and a sustainable heat source. Additionally, Gosnold *et al.* (2017) also suggested four recommendations based on this project: 1) evaluating the quantity of energy in the Bakken formations, 2) the potential fluid production, 3) the most appropriate energy conversion system, and 4) local electrical power market.

METHODS

There are several oil and gas multi-well pads in the three study areas where these wells are directionally drilled into the Bakken Formation, which might have a sufficiently high temperature and flow rate. Theoretically, this suggests that repurposing these oil and gas wells into geothermal use might bring new economics to the local communities and oil companies as well. In order to achieve the research goals, this study examined the current accessible production volume of fluids, stored thermal energy estimation, identification of the appropriate energy conversion system, evaluation of the flow rates through finite-difference heat flow simulation, and economic estimation of the installation of power plants. Therefore, I investigated whether the current Bakken oil and gas wells might yield economic geothermal power or not. This would be a possibility if the wells' bottom-hole temperatures are sufficiently high and have enough volume of fluid. To determine the economic feasibility of this study, the method consists of a five-component analysis to evaluate the economics for producing the resource, which are:

1. Assess the volume of fluids in the study areas
2. Estimate the stored energy
3. Identify the appropriate energy conversion system
4. Evaluate the flow rates via finite difference heat flow simulation
5. Estimate the installation cost of the power plants

The Volume of Fluids in Study Areas

The NDIC database provides data for the fluid volumes of oil and water for the Sanish, Parshall, and Banks Bakken fields between 2008 and 2018. The well-developed fields -Sanish and Parshall - produced significantly more oil than water in early production periods (Figures 7, 8). However, the developing Banks field produced only slightly more oil than water until 2016. And then, it began to produce more water than oil (Figure 9). The oil fields’ monthly production chart showed that the current water-oil ratio (WOR) for the Bakken wells was close to 1:1. At the same time, the average for conventional US oil and gas fields WOR has been 7.5:1. And the average WOR for all ND oil fields was 3:1 (Clark *et al.*, 2009). So, oil depletion during the production frequently leads to increased water production. As seen in Figures 7, 8, and 9, the Sanish and Parshall Bakken fields showed oil depletion over the last decade. However, the Banks Bakken field has been one of the developing oil fields. It has been producing a significant amount of fluid production over the last decade. Subsequently, the average total production for these oil fields has varied with time, mainly due to variations in world oil prices (Gosnold et al., 2019). Thus, the ten-year averages and trends provide less than robust data sets for geothermal analysis. Due to the rapidly developing oil and gas wells' activities, we are more likely to understand and illustrate near real-time production data in these study areas. Therefore, I used the most recent production data from 2018, specifically in the last six months (June - December) of the year (Table 1).

Table 1. 2018 June – December Average Production Volume

2018 (June -December)	Average Total Production Volume (10^6)		
Oil Fields	Active well number	Oil (*liters /day)*	Water (*liters /day)*
Parshall	475	5.12	4.34
Sanish	656	8.75	7.86
Banks	252	9.23	11.18

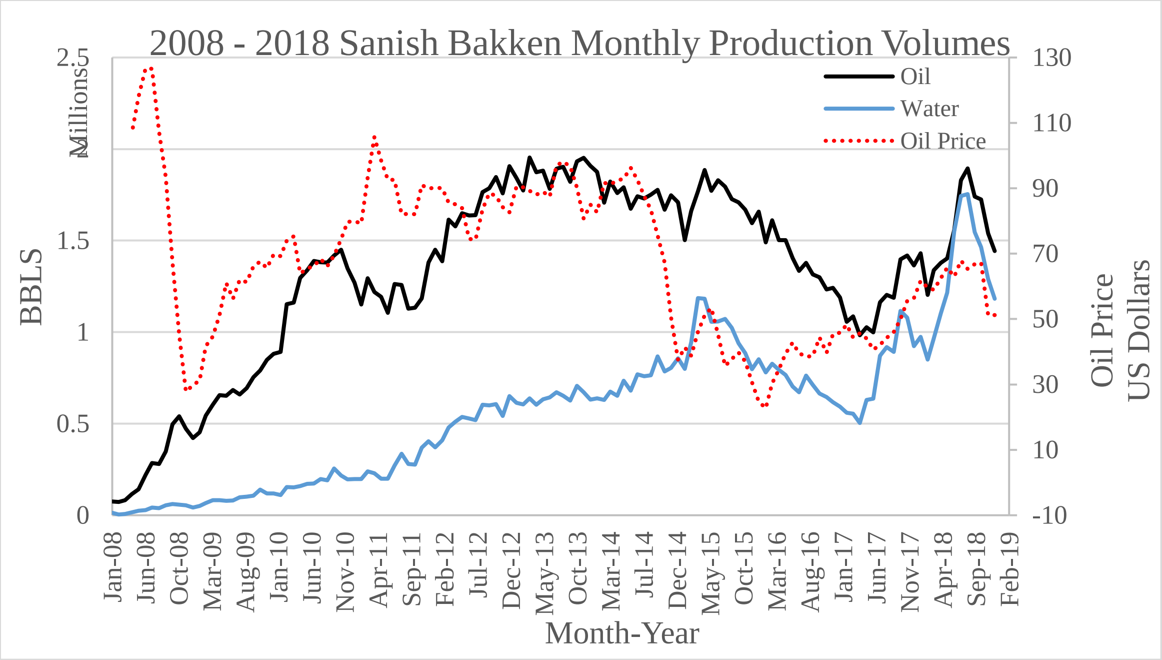


Figure 7. 2008 – 2018 Sanish Bakken Monthly Production

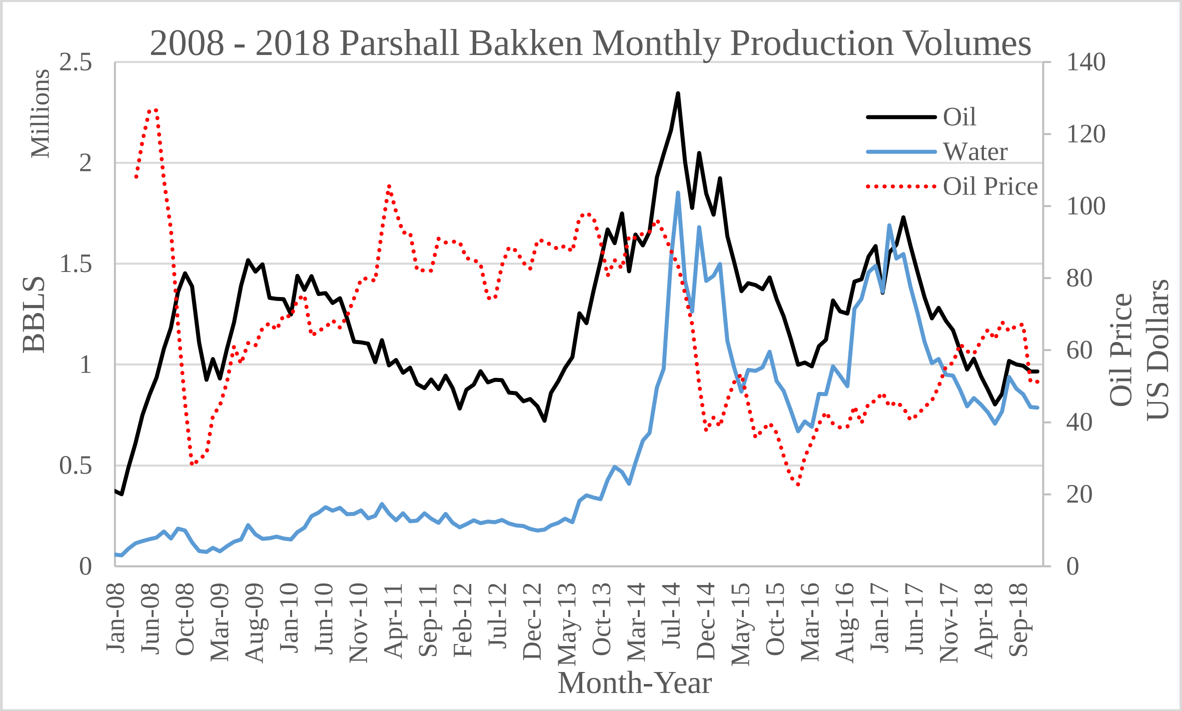


Figure 8. 2008 – 2018 Parshall Bakken Monthly Production

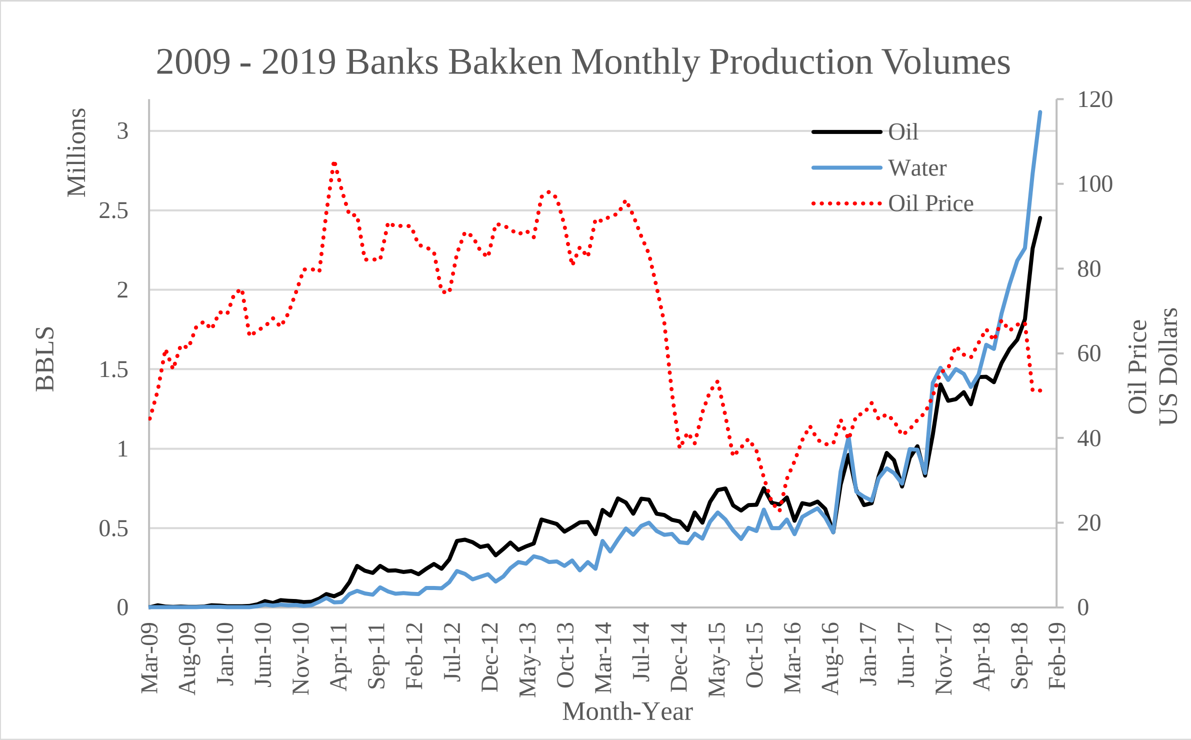


Figure 9. 2009 – 2019 Banks Bakken Monthly Production

Thermal Energy Calculation

Based on the study areas' fluid production data, the thermal energy can be calculated by using the energy equation $Q = \rho V c_v \Delta T$. However, due to the fluid's properties and WOR, the thermal energy equation needs to be transformed to Eq.3 (Vraa et al., 2019). The thermal energy is a function of the fluid's density, specific heat capacity, flow rate, WOR, and change in temperature. The conversion allows for a more accurate calculation of the thermal energy by computing the following equation:

$$E_{th} = (\rho_{oil} c_{p\ oil} + WOR * \rho_{water} c_{p\ water})\ Q_t \Delta T/(WOR+1) \qquad \text{Eq. 3}$$

where:

ρ = Fluid density (kg m^{-3})

c_p = Fluid heat capacity (J kg^{-1} $^{o}C^{-1}$)

Q_t = Quantity of fluid flow (m^3 s^{-1}),

ΔT = Fluids' change in temperature (ºC),

WOR = Fluids' water-oil ratio (-).

The 2.78 x 10^{-7} kWh J^{-1} is used to calculate the conversion from thermal to electric energy. The Bakken Formation's optimistic temperature is approximately 100 – 143ºC (Gosnold et al. 2019). While this temperature ranges might be high than its actual formation temperatures. The Calnetix and ENO units' temperature drop (ΔT) is 30ºC, while the Climeon module ΔT is 50 ºC (Gosnold *et al.*, 2019). The fluid's physical and thermal parameters are used for energy calculation (Table 2), which then enabled calculation for the stored energy in the three oil fields (Table 3). Therefore, using Eq 3 and thermal energy to electrical energy conversion factor 2.78 x 10^{-7} kWh J^{-1} to calculate the potential power range. The calculation shows that the Parshall, Sanish, and Banks Bakken oil production fields might generate the potential power range from 1.3 MWh to 7.5 MWh.

Table 2. Oil and water density and heat capacity parameters for ORC units: #1 is the Calnetix 125 kW Thermapower® ORC, #2 is the Climeon Heat Power System 150 kW module, and #3 is the ENOGIA 40Lt unit (Gosnold et al., 2019)

Fluid	**ρ (kg m^{-3})**	**c_v (J kg^{-1} °C $^{-1}$)**	**ΔT(°C) #1 & #3**	**ΔT (°C) #2**
Oil	870 - 920	1830 - 2130	30	50
Water	997 - 1030	3993 - 4186	30	50

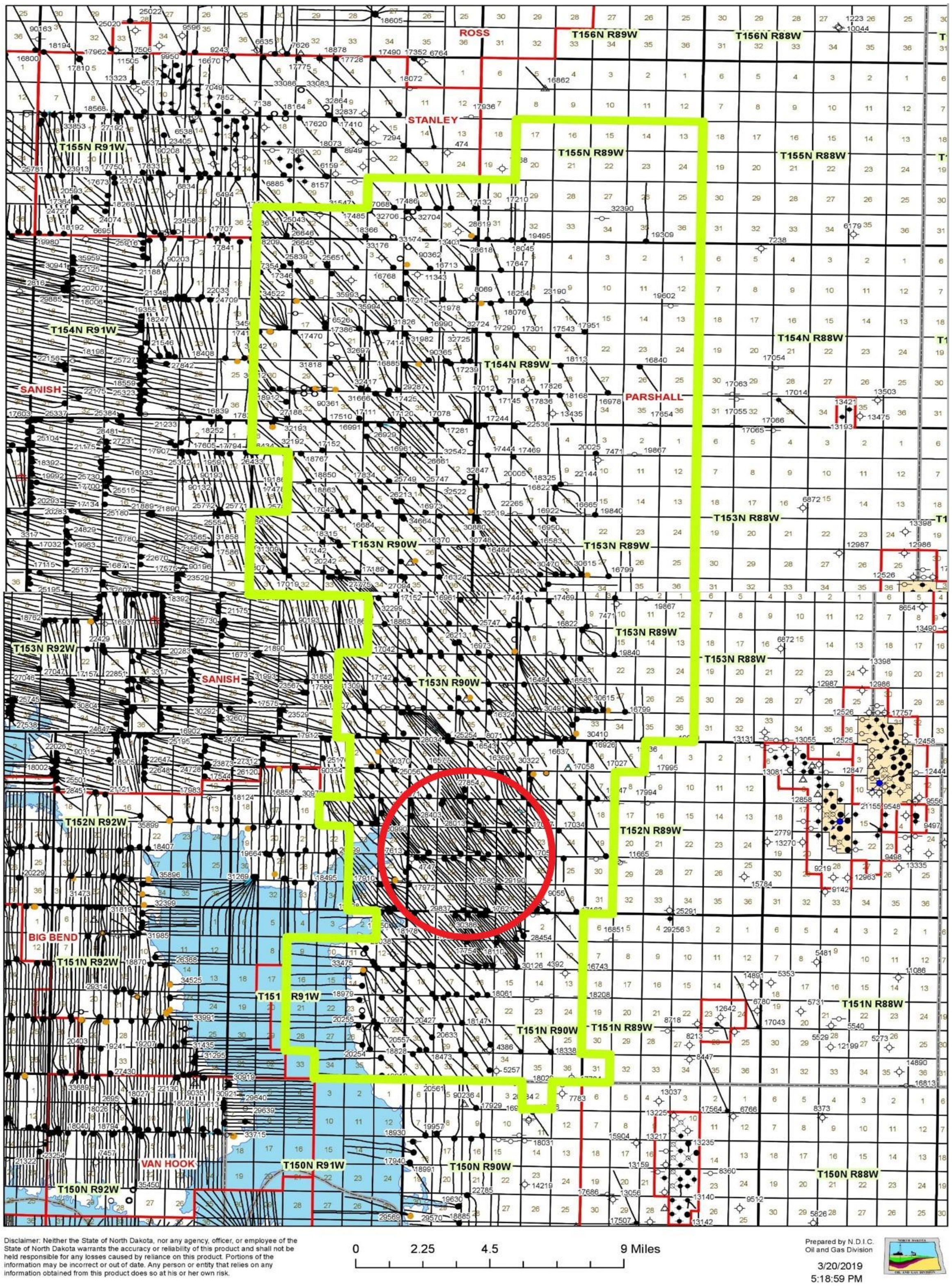
Table 3. The study fields stored energy calculation (2019)

Field	**Active Well #**	**Oil (L/s)**	**Water (L/s)**	**Energy (J)**	**kWh #1**	**kWh #2**	**kWh #3**
Parshall	475	59.28	50.28	3.36 x 10^{10}	875.33	1307.63	1680.00
Sanish	656	101.29	90.97	8.77 x 10^{10}	2682.92	3411.00	4385.00
Banks	252	106.87	129.44	1.94 x 10^{11}	7677.49	7547.82	9700.00

The study areas look promising for potential power generation development, considering the total flow rate and stored energy in the Bakken Formation. However, to effectively connect the multi-well pads, it is important that individual wells have a significant production flow rate. The data from Table 4 illustrates the production flow rates and temperatures of the wells that lie with a 2.5-mile radius of the study areas. In this calculation, I assumed that years of production had not modified the subsurface temperature. Additionally, the study areas have a range of 30 to 110 active wells, while the wells' bottom hole temperature ranges from 100 to 143 °C and the total fluid flow rate ranges from 5 to 26 l/s (Table 4). However, using these parameters allows for the calculation of stored thermal energy in these oil fields. The stored energy in the study fields is calculated by Eq 3, where the thermal energy ranges from 1.34×10^9 to 11.15×10^9 J and is convertible via ORC units into electric energy.

Table 4. Energy calculation for the study areas

Oil Field	Well #	The Bakken temperature (°C)	Oil (L/s)	Water (L/s)	Total fluid flow rate (L/s)	Flow rate per well (L/s)	WOR	Energy (10^9J)	Calnetix Net Energy		Climeon Net Energy		ENO Net Energy	
									kWh	**Efficiency**	**kWh**	**Efficiency**	**kWh**	**Efficiency**
Parshall	113	100	9.15	12.53	21.68	0.19	1.37	6.45	192.91	6%	288.18	14%	340.05	18%
Sanish #1	30	114	3.68	2.11	5.79	0.19	0.57	2.16	42.08	6%	104.76	14%	123.62	18%
Sanish #2	37	114	3.98	0.69	4.66	0.13	0.17	1.34	26.15	6%	65.12	14%	76.84	18%
Banks #1	33	143	7.58	13.16	20.75	0.63	1.73	9.91	193.56	6%	481.92	14%	568.67	18%
Banks #2	55	143	12.39	13.38	25.77	0.47	1.08	11.15	217.74	6%	542.13	14%	639.71	18%



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Oil and Gas Division
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Figure 10. Study location of Parshall Field (red circled area, NDIC 2019)

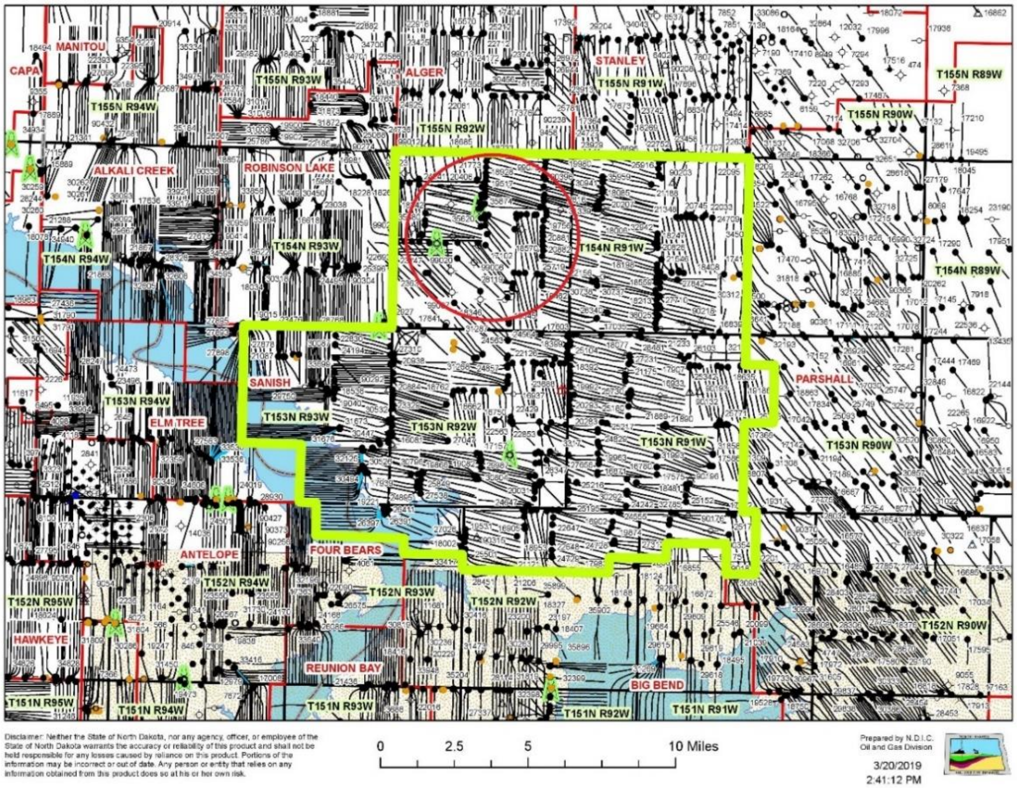


Figure 11. #1 Study location of Sanish Field (red circled area, NDIC 2019)

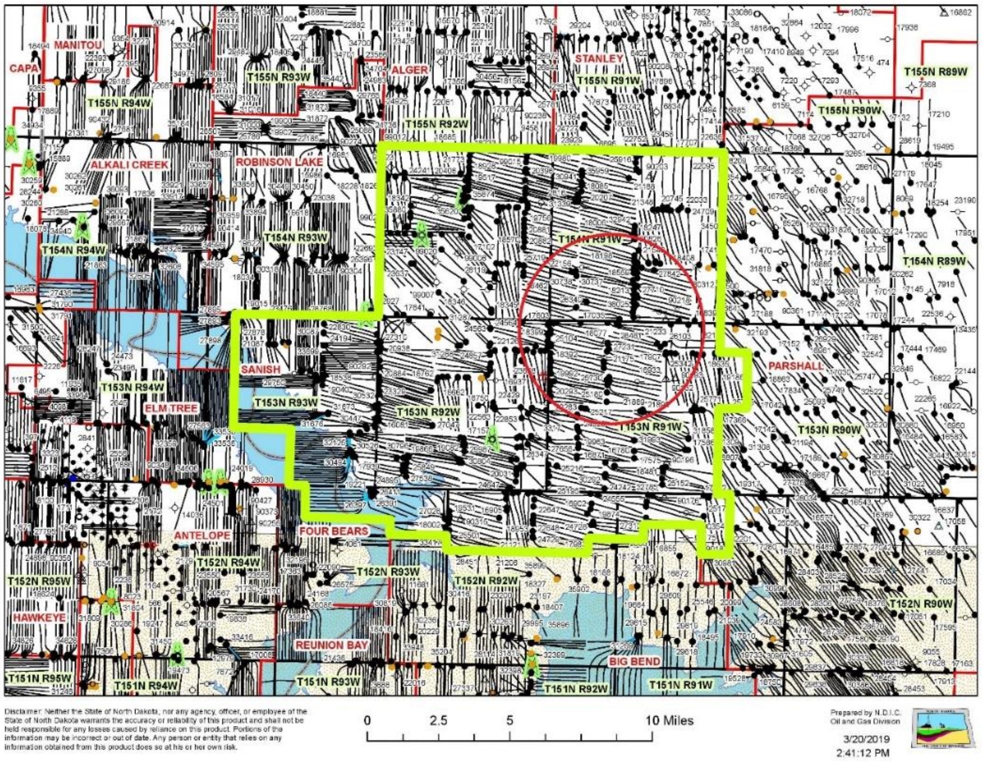


Figure 12. #2 Study location of Sanish Field (red circled area NDIC 2019)

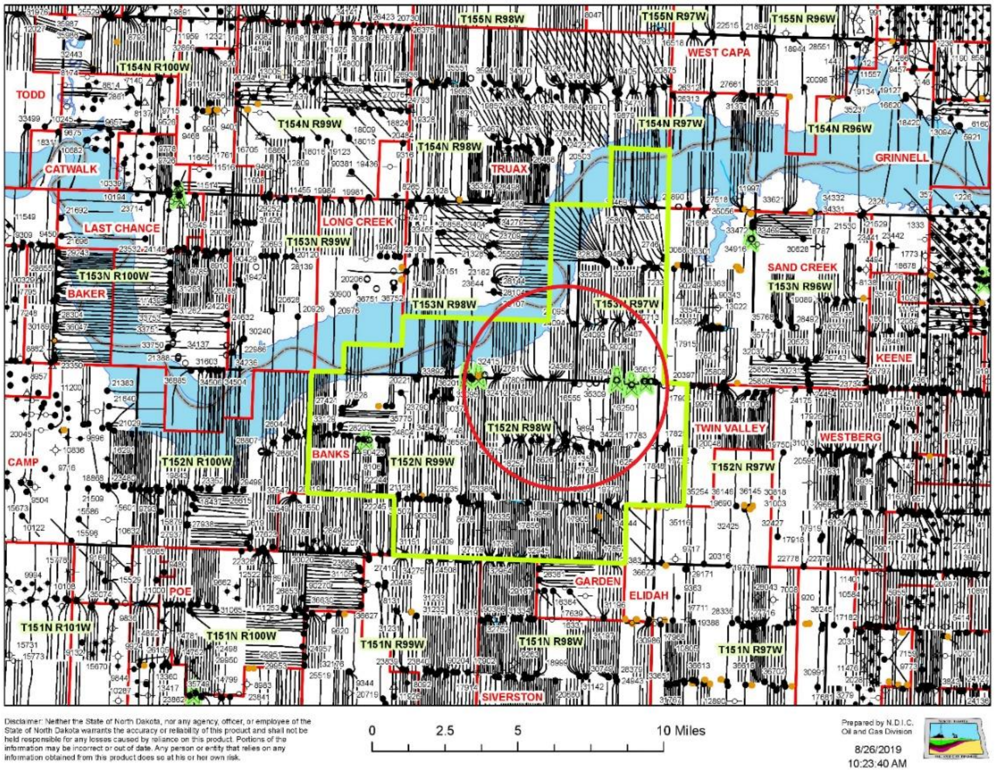


Figure 13. #1 Study location of Banks Field (red circled area NDIC 2019)

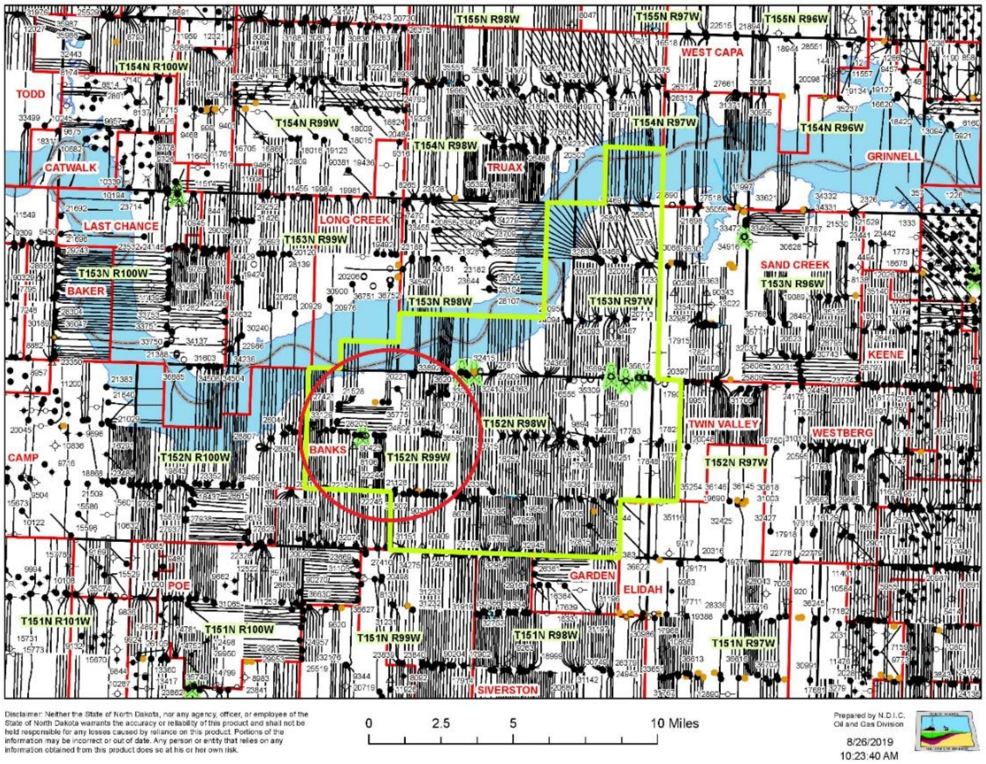


Figure 14. #2 Study location of Banks Field (red circled area NDIC 2019)

Finite Difference Heat Flow Simulation

This project utilized the finite difference method (FDM) because it is a widely used approach for solving linear differential equations (Özişik et al., 2017). The purpose of this finite-difference heat flow simulation is to observe temperatures at different flow rates. The FDM is specifically used on applications in the areas of heat transfer and fluid flow. This heat flow model does not intend to simulate a real situation, and rather it is merely a test for the Bakken wells. There are several crucial parameters to evaluate the recoverable heat fraction: porosity and permeability, rock temperature, fluid flow rate, and well configuration (Sanyal et al., 2005). The model shows the thermal energy that could be mined for a specified set of reservoir properties and geometry. This model assumes that constant heat flow at the base is steady at 50 mWm^{-2}, while the formation's thermal conductivities are considered homogenous. The model used four different flow rates to determine the rate of heat dissipation overtime in four wells: 0.4, 0.6, 0.8, and 1.0 l/s respectively for a one-year period (Figure 15, 16). While the flow rates changed, the model parameter for the BHT is 135°C, formation depth of 2500 meters (8202 ft) using a grid point difference spacing of 10 m (33 ft) on a 500 by 500 grid. Additionally, each well contained a 10.2 cm (4 inch) horizontal tube in a 20 cm (8 inch) hole that is grouted with cement around the tube. This model result shows that different flow rates yield different temperatures at the surface of the wellhead (Table 5).

Table 5. shows the result for the finite-difference heat flow simulation

Model Simulated time (yr.)	1			
Flow rate (l/s)	0.4	0.6	0.8	1
Surface Temperature (°C)	56	64	75	83

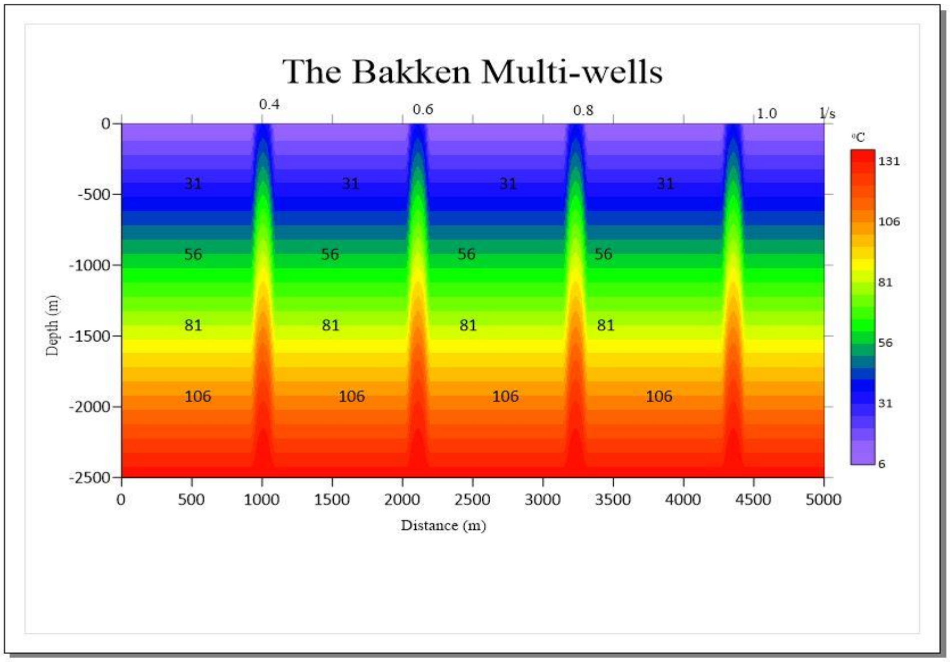


Figure 15. 2D Bakken multi-wells temperature profiles at flow rates at 0.4, 0.6, 0.8, 1.0 l/s

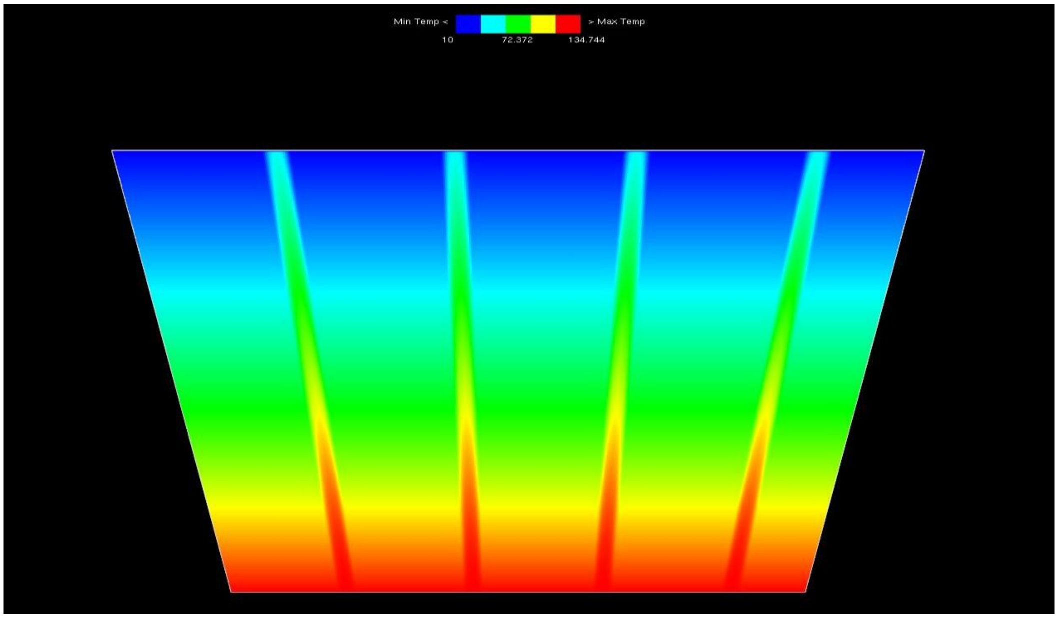


Figure 16. The screenshot of running finite difference heat flow model

Energy Conversion Systems

In order to utilize the Bakken multi-well pads for the geothermal power generation, I analyzed three different geothermal power generation systems: Climeon 150 kW Heat Power System, Calnetix 125 MT Thermapower® ORC unit, and ENOGIA 40-LT ORC system (Table 6). These systems were looked at individually because they can tolerate water-oil fluid mixture, which allows for full use of the total fluid flow.

Table 6. The system power generation capability and the unit price

Developer	**Unit**	**Gross Power Generation (kW)**	**Oil Tolerance**	**Price ($)**
Climeon	Heat Power System	150	Yes	340,000
Access Energy	Thermapower® ORC	125	Yes	250,000
ENOGIA	ENO-40LT	40	Yes	108,000

Organic Rankine Cycle (ORC) Working Principle

The binary ORC working principle describes the low-temperature geothermal fluid flows through the ORC unit. Inside each unit, a heat exchanger transfers the heat to an internal fluid, which vaporizes due to its lower boiling point. The vapors expand and drive a turbine to run a generator and produce electricity (Figure 17). In order to achieve greater efficiency, the Calnetix's system decreases parasitic energy loss using an Insight™ magnetic bearing controller (MBC), which is a non-contact, no lubrication, and low maintenance controller. The MBC is eliminating the turbine-to-gearbox with magnets in the turbine blades. The Calnetix system uses a single pass of geothermal fluid to generate gross power up to 125 kW per unit. The system efficiency ranges from 6 to 14%.

The system working fluid can be customized to a low-temperature fluid of 95°C (Gosnold et al., 2019). The Climeon Heat Power 150 kW module, on the other hand, can optimize for low-temperature resources (70-120°C). This system is flexible and easily scalable from 150 kW modules to several MWs for larger installations. This system requires a minimum of 10 to a maximum of 30 l/s flow rate, and each module can extract the heat efficiently. For example, the heat source temperature starts at 100°C in the first module then passes into the second module, and the temperature drops to 90°C. Then fluid flow through a third module, and temperature reduces to 80°C. In this way, this system effectively utilizes the heat source and achieve greater efficiency. Gosnold claims, "the system achieves >50% Carnot efficiency, >10% net efficiency for the heating temperature at 90°C and cooling temperature at 20°C due to high turbine efficiency, minimum losses in heat exchanging operations and minimum internal power requirements" (Gosnold et al., 2017).

The ENO-40LT module is able to recover up to 640 kWth and gross power output of 40 kWe from low-temperature sources (70-120°C). This module is being achieved greater efficiency by two high speed patented micro-turbines. The module efficiency ranges from 6-18%.

There are seven stages that the system must have:

Stage 1: The heat source transfers thermal energy into the refrigerant, causing it to vaporize.

Stage 2: High-pressure refrigerant vapor flows into the turbine.

Stage 3: The refrigerant vapor pushes against the turbine and causes it to spin.

Stage 4: The turbine turns the generator producing electrical power.

Stage 5: Cooling air or water extracts heat from the low-pressure refrigerant vapor.

Stage 6: The refrigerant is condensed back into the liquid state.

Stage 7: Liquid refrigerant pumps into the evaporator.

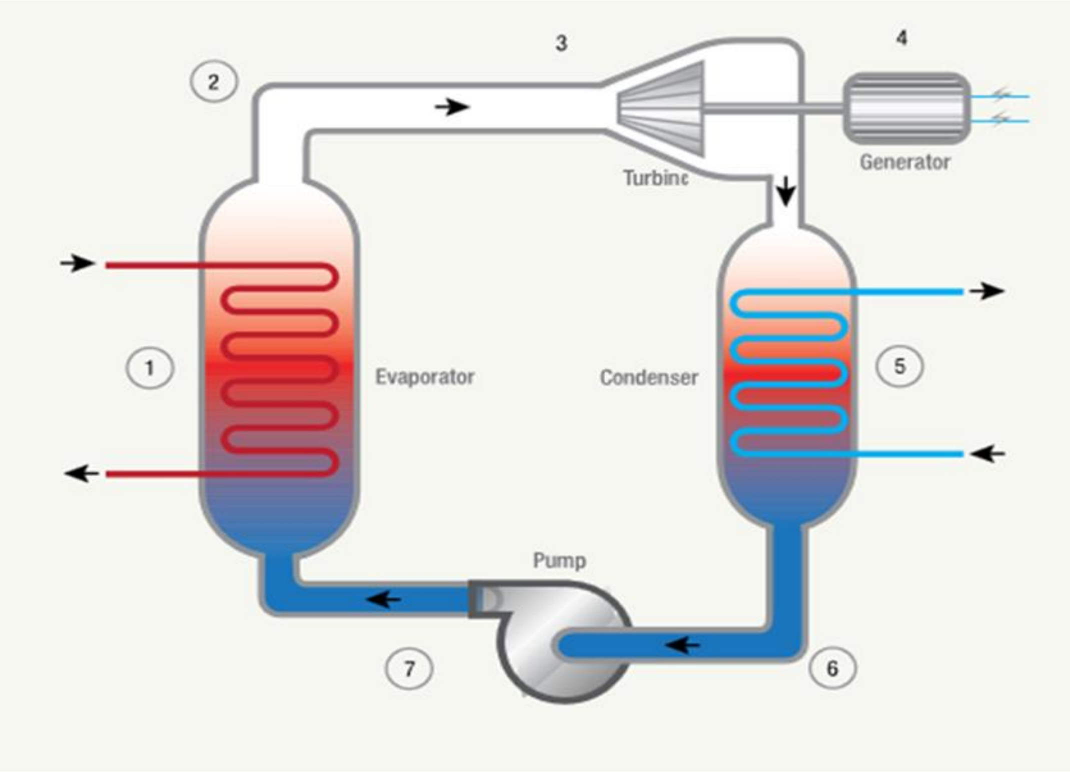


Figure 17. Organic Rankine Cycle (ORC) working principle illustration. (Adapted from Calnetix Technologies)

Climeon Heat Power System

The Climeon Heat Power System 150 kW module is still being developed by a company in Sweden (Figure 18). The Climeon system is based on ORC technology that utilizes the geothermal heat into clean electricity as a complete product, which consists of three moving parts per module: a turbine and two pumps. The system operates at low-pressure levels in comparison to traditional heat power solutions and allows delivery of up to 50% higher efficiencies than other solutions while creating a smaller CO_2 footprint (Climeon Tech Product Sheet). The system operates at low pressure 2.5 bar, which requires modular design and makes the system easily scalable from 150 kW modules to 50 MW for serial and parallel installations where the system's efficiency is up to 14% (Table 7). The Climeon control system is fully automatic, which optimizes performance in real-time to ensure maximum energy generation (Climeon Tech Product Sheet).

Figure 18. The Climeon Heat Power System 150 kW module

Table 7. The Climeon Heat Power System Specifications

Module	**One Module 150 kW**	**Power Block (7 modules) 1MW**
Height mm	2270	2270
Depth mm	2105	2105
Width mm	2085	14700
Weight kg	9000	63000
Electrical Cabinet		
Height mm	2100	2100
Depth mm	600	600
Width mm	2200	13600
Weight kg	1200	6100
Heating Circuit		
Module flange connections *ISO*	DN125/PN10	DN125/PN10
Flow rate l/s	10 - 50	70 - 350
Inlet temperature max ºC	120	120
Module flange connections *ISO*	DN125/PN6	DN125/PN6
Flow rate l/s	10 - 50	70 - 350
Min cooling inlet temp. ºC	0	0
Max cooling inlet temp. ºC	35	35
Electrical Specification		
Max net output power *kW*	150	1050
Voltage selectable *V*	400/690	400/690
Frequency selectable *Hz*	50/60	50/60

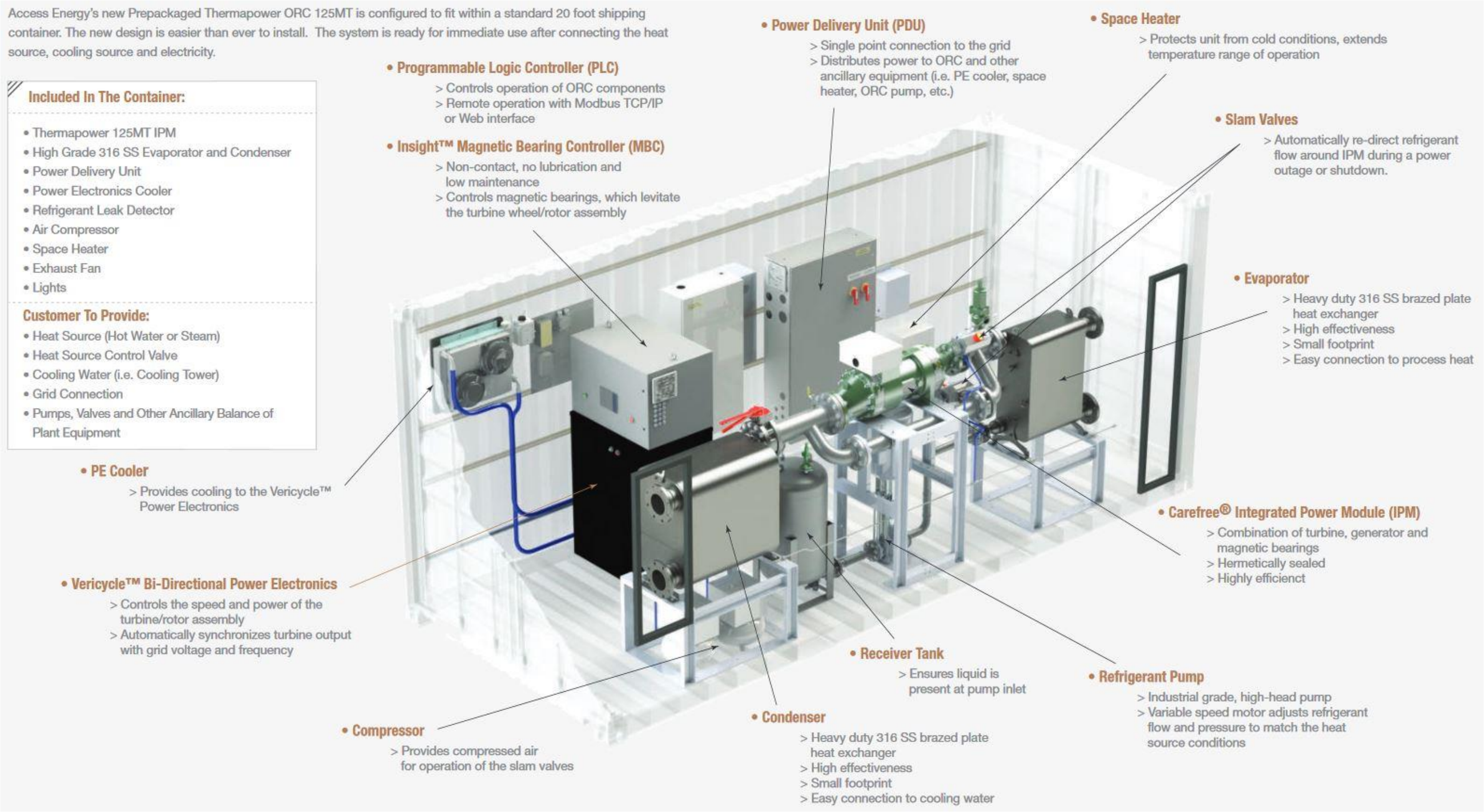
Calnetix 125 MT Thermapower® ORC unit

The Calnetix 125 MT Thermapower® ORC unit is still being developed and manufactured by Access Energy (Figure 19). The system can generate 125 kWe of clean power from low-temperature heat sources that range from 95ºC to 130ºC, where efficiency ranges from 6% to 14% (Table 8). The new customized system can effectively harvest the heat from the lower temperature resources (95 - 120ºC), which is available in the Williston Basin. The system working fluid is HFC-R245fa, also known as pentafluoropropane. Its boiling point is 15.3ºC, which can also be customized for a low-temperature heat source. This unit is the Carefree® Integrated Power Module (IPM), which operates on magnetic bearings and minimizes maintenance (Figure 20). The unit has portable dimensions, as seen in Figure 21 that enables it to be more effective than bulkier units (Calnetix AE ORC 125 MT Brochure, 2016).

Figure 19. The Calnetix 125 MT Thermapower® ORC unit

Table 8. The Prepackaged Calnetix 125 MT Thermapower® ORC unit Specifications

Parameter	**Value**
Power	125 kW Gross
Voltage/Frequency	380-480 VAC; 50/60 Hz
Input Temperature	95ºC - 130ºC (203 F - 266 F)
Working Medium	R245fa
Weight	7800kg (17200lb)
Size	6m (20 ft) ISO Container
Connection	**Description**
Evaporator Inlet/Outlet	10 cm (4 inch) CL300 RF ASME B 16.5 Flange
Condenser Inlet/Outlet	15 cm (4 inch) CL300 RF ASME B 16.5 Flange
Grid Connection	3-Phase 3 Wire with Ground
Internet Connection	Ethernet CAT-5 Cable from Customer Internet



Access Energy's new Prepackaged Thermapower ORC 125MT is configured to fit within a standard 20 foot shipping container. The new design is easier than ever to install. The system is ready for immediate use after connecting the heat source, cooling source and electricity.

Included In The Container:

- Thermapower 125MT IPM
- High Grade 316 SS Evaporator and Condenser
- Power Delivery Unit
- Power Electronics Cooler
- Refrigerant Leak Detector
- Air Compressor
- Space Heater
- Exhaust Fan
- Lights

Customer To Provide:

- Heat Source (Hot Water or Steam)
- Heat Source Control Valve
- Cooling Water (i.e. Cooling Tower)
- Grid Connection
- Pumps, Valves and Other Ancillary Balance of Plant Equipment

- **PE Cooler**
  - > Provides cooling to the Vericycle™ Power Electronics

- **Vericycle™ Bi-Directional Power Electronics**
  - > Controls the speed and power of the turbine/rotor assembly
  - > Automatically synchronizes turbine output with grid voltage and frequency

- **Compressor**
  - > Provides compressed air for operation of the slam valves

- **Programmable Logic Controller (PLC)**
  - > Controls operation of ORC components
  - > Remote operation with Modbus TCP/IP or Web interface

- **Insight™ Magnetic Bearing Controller (MBC)**
  - > Non-contact, no lubrication and low maintenance
  - > Controls magnetic bearings, which levitate the turbine wheel/rotor assembly

- **Condenser**
  - > Heavy duty 316 SS brazed plate heat exchanger
  - > High effectiveness
  - > Small footprint
  - > Easy connection to cooling water

- **Receiver Tank**
  - > Ensures liquid is present at pump inlet

- **Power Delivery Unit (PDU)**
  - > Single point connection to the grid
  - > Distributes power to ORC and other ancillary equipment (i.e. PE cooler, space heater, ORC pump, etc.)

- **Space Heater**
  - > Protects unit from cold conditions, extends temperature range of operation

- **Slam Valves**
  - > Automatically re-direct refrigerant flow around IPM during a power outage or shutdown.

- **Evaporator**
  - > Heavy duty 316 SS brazed plate heat exchanger
  - > High effectiveness
  - > Small footprint
  - > Easy connection to process heat

- **Carefree® Integrated Power Module (IPM)**
  - > Combination of turbine, generator and magnetic bearings
  - > Hermetically sealed
  - > Highly efficienct

- **Refrigerant Pump**
  - > Industrial grade, high-head pump
  - > Variable speed motor adjusts refrigerant flow and pressure to match the heat source conditions

Figure 20. Calnetix Thermapower® ORC 125MT unit and its labels in 20-foot (6.1 meter) shipping container (Adapted from Calnetix AE ORC 125 MT Brochure)

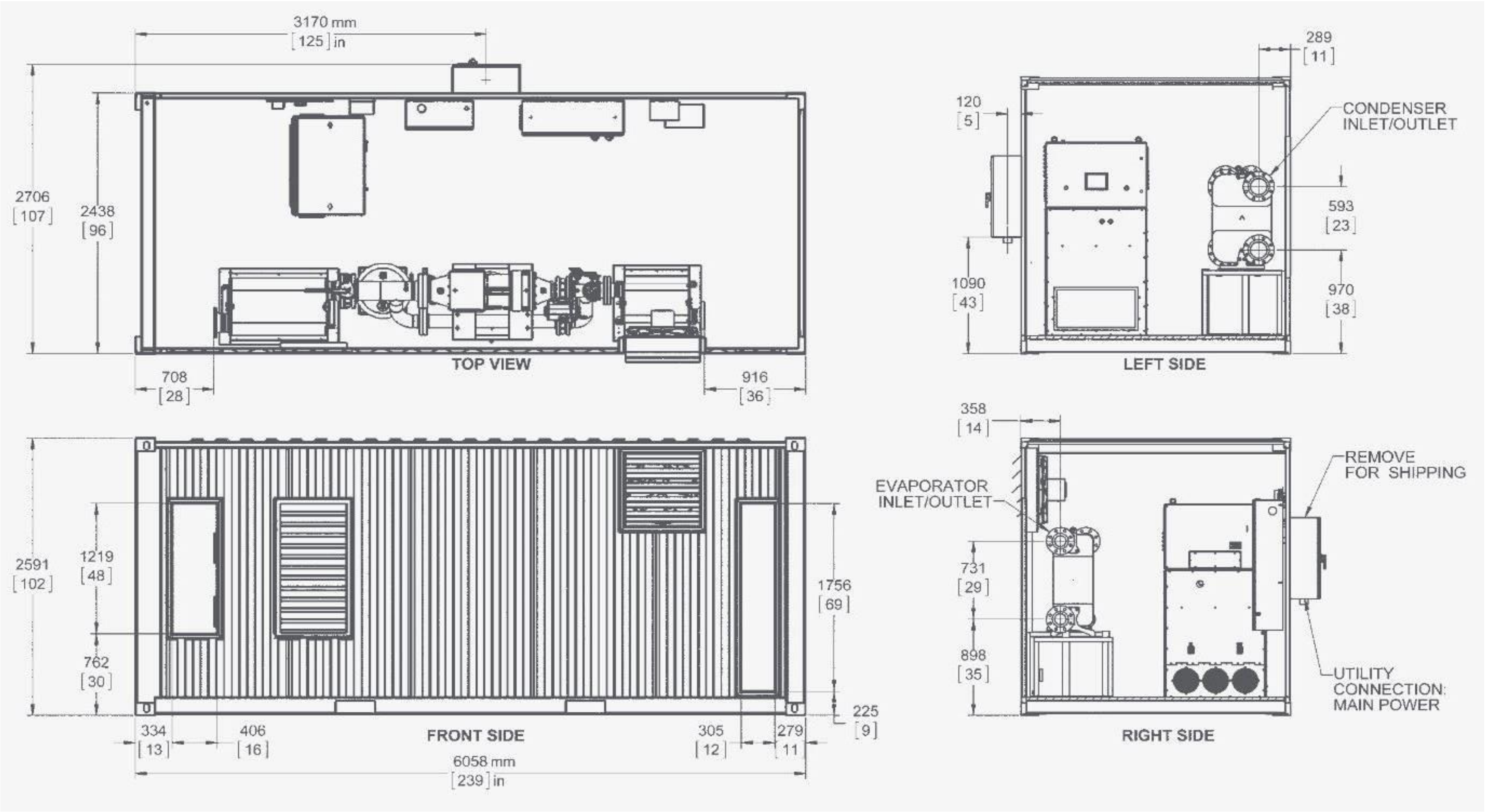


Figure 21. Calnetix Thermapower® ORC 125MT unit and its labels in 20-foot (6.1 meters) shipping container (Adapted from Calnetix AE ORC 125 MT Brochure)

ENOGIA ORC system

The ENO-40 LT module (Figure 22) is an ORC developed and manufactured by a French company called ENOGIA (Figure 23). The ORC unit capability is up to 640 kWth and nominal power production of 40 kWe from low-temperature heat sources with a temperature range of 70 ºC - 120 ºC (Table 9). The ORC unit transforms efficiency kWth to kWe at 6 – 18 % depending on the fluid temperature and ORC working fluid.

Figure 22. ENO-40LT module (Adopted from ENO-40 LT Datasheet)

Table 9. ENO-40LT Characteristics data (Adopted from ENO 40LT Datasheet)

Electrical ratings	Maximum gross electric power [kWe]	40
	Grid connection	400V, 3ph neutral + earth, 50-60 Hz
Heat source	Temperature range [°C]	70-120
	Thermal power input range [kWth]	450-640
	Hot source medium	Water, steam, oil
	Hydraulic connections	DN 80, PN16
Cold source	Temperature range [°C]	0-60
	Working fluid	Water
	Cooling system	Dry cooler, cooling tower
	Hydraulic connections	DN 100, PN16
Main components	Working fluid	R1233zd
	Generator	High speed, permanent magnet
	Expander	Kinetic turbine
	Heat exchangers	Brazed plate
	Pump	Multi-stage magnetic coupling
	Controls	Industrial PLC
	Monitoring	Remote web support
Main ratings	Weight [Kg]	1365
	Dimensions L x W x H (mm)	1980 x 1200 x 1900
	Environmental	IP 20
	Noise level [dB] @10m	60
	Design lifetime [yrs.]	20
	Safety	Non-flammable, non-toxic, ODP=0
Norm compliance	Machine directive	2006/42/EG
	PED	2014/68/EU
	Electrical norms	2014/35/EG
	Grid codes	VDE-0126 (G59, VDE-ARN, UL)

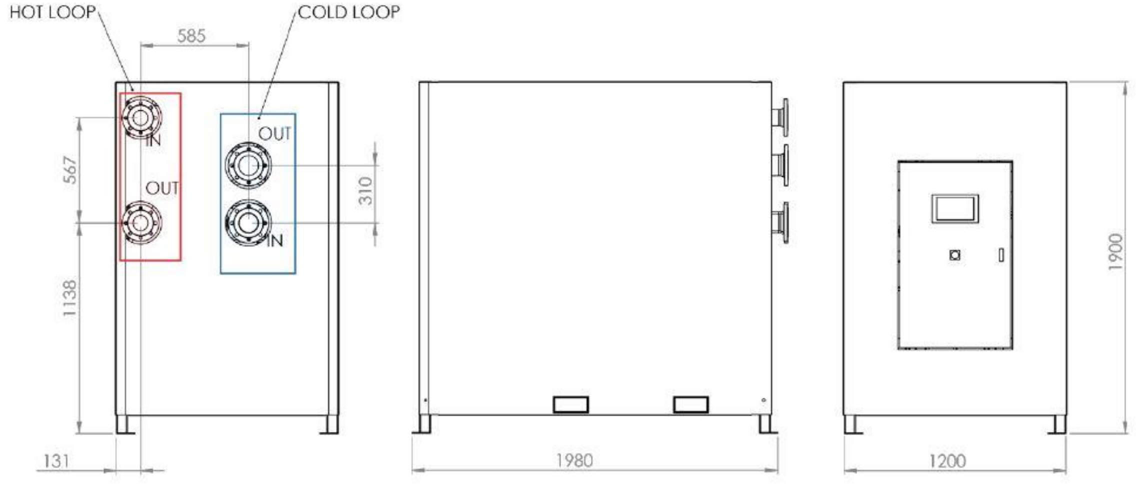


Figure 23. ENO 40LT Dimensions

ECONOMIC ANALYSIS

In conducting an economic feasibility study for generating geothermal power from oil and gas producing wells in the Williston basin, I considered the following factors:

- Landowners share
- Reservoir sustainability
- Power plant size
- Estimated ORC unit price
- Transmission availability and capacity
- Market factors, such as raw material

In order to estimate the cost-of-energy, minimum revenue per unit production, and minimum required after-tax rate of return for investors. I used the three different types of geothermal power generation units: The Climeon 150 kWe Heat Power System, Calnetix 125 MT Thermapower® ORC unit, and ENOGIA 40LT. The economic analysis used the CREST model shared by the US National Renewable Energy Laboratory (NREL) website.

Feasibility Assessment

In economic feasibility analysis, three primary requirements need to be met for power generation for the development of geothermal resources such as heat source, sustainable fluid flow rate, and high transform efficiency. If one of the factors is inadequate, a project's development is not economical.

Based on the results of the energy calculation (Table 4.), I adopted three scenarios for geothermal power generation with capacity factors at 90%. Due to the temperature in

Bakken Formation and a sufficient flow rate, I used the # 2 study area in the Banks Bakken oil field for this analysis (Table 10). I assumed three scenarios to determine power generation based on ORC unit efficiency and oil well flow rate:

Scenario 1: includes three ENOGIA 40 LT ORC units.

Scenario 2: includes two Calnetix 125 MT Thermapower® ORC units.

Scenario 3: includes two Climeon 150 kW Heat Power Systems.

Table 10. Scenario Parameters

Items	**Unit**	**Scenario 1**	**Scenario 2**	**Scenario 3**
Formation temperature	°C	143	143	143
Flow rate	L/s	25	25	25
Gross plant size	kWe	120	250	300
Net plant size	kWe	108	225	270
Well depth	m	2750	2750	2750
Number of production wells	-	55	55	55
Number of injection wells	-	2	2	2

Economic Data and Assumptions

According to the North Dakota Office of State Tax Commissioner, in order to qualify for a tax exemption, the geothermal facility is required to use at least one electrical generation unit with a capacity of 100 kilowatts or more. The analysis had assumed financial parameters, which included a required minimum of an annual interest rate of 7%, and the average Debt Service Coverage Ratio (DSCR) was 1.1, Internal Rates of Return (IRR) (Table 11). To complete the economic analysis, I used the CREST geothermal model (Gifford, Grace, & Rickerson, 2011), version 1.1. The installed cost of a geothermal power system includes the estimated costs for raw materials, direct and indirect construction, and financing. The geothermal power system economics also depends on development costs and the sale price for electricity (Hillesheim et al., 2013). Although the cost-based federal incentives are assumed as received, it is crucial to find incentives or grants to make geothermal power generation cost-effective (Hillesheim et al., 2013). Many factors go into geothermal pipeline design/cost (fluid type, fluid volume, elevation, pressure, pipe material, etc.). Most engineers in the pipeline industry use a "rule of thumb" of "dollars per inch-mile" that typically range from \$40,000-\$75,000 per inch-mile, which includes all associated costs (labor, materials, etc.). For example, using ~\$60,000 per inch-mile, a 4"-5-mile pipeline would be 4 x 5 x \$60,000 for a total of \$1,200,000 (Justin Kringstad per communication, North Dakota Pipeline Authority). I assumed connecting wells cost \$800,000. The estimated cost for the system's installation, including all site preparation and electrical interconnection was \$350,000 (Table 12). Also, Access Energy disclosed that two Calnetix units' delivery price estimated was \$520,000 (Gosnold et al., 2017). The Climeon System unit price estimated was \$340,000, not including delivery costs. The ENO ORC unit price was estimated at \$108,000 (Vraa et al., 2019).

The Levelized Cost of Energy (LCOE) must be covered by the project's electricity generation and sustain investors' IRR over the project's lifetime, which is considered approximately 30 years or more. In the oil industry, IRR ranges from 14 to 16%.

Table 11. The CREST Model Summary

Outputs Summary	***units***	***ENOGIA Model Run***	***Calnetix Model Run***	***Climeon Model Run***
Year-One Cost of Energy (COE)	*¢/kWh*	19.15	11.45	10.95
Annual Escalation of Year-One COE	*%*	0.0%	0.0%	0.0%
Percentage of Tariff Escalated	*%*	0.0%	0.0%	0.0%
Equivalent Nominal Levelized Tariff Rate	*¢/kWh*	19.15	11.45	10.95
Inputs Summary				
Generator Nameplate Capacity	*MW*	0.12	0.25	0.3
Net Capacity Factor, Yr. 1	*%*	90.0%	90.0%	90.0%
Annual Degradation of Thermal Resource	*%*	0.0%	0.0%	0.0%
Payment Duration for Cost-Based Incentive	*years*	25	25	25
Project Useful Life	*years*	30	30	30
Exploration	*$*	$804,000	$803,975	$803,975
Power Plant	*$*	$694,000	$870,000	$1,030,000
Reserves & Financing	*$*	$24,494	$32,722	$36,522
Net Project Cost	*$*	$1,428,994	$1,613,197	$1,817,947
Net Project Cost	*$/kW*	$11,908	$6,453	$6,060
% Equity (% hard costs) (soft costs also equity funded)	*%*	50%	50%	50%
Target After-Tax Equity IRR	*%*	12.00%	12.00%	12.00%
% Debt (% of hard costs) (mortgage-style amort.)	*%*	50%	50%	50%
Interest Rate on Term Debt	*%*	7.00%	7.00%	7.00%
Is the owner a taxable entity?		Yes	Yes	Yes
Type of Federal Incentive Assumed		Cost-Based	Cost-Based	Cost-Based
Tax Credit Based or Cash-Based?		Cash Grant	Cash Grant	Cash Grant
Other Grants or Rebates		Yes	Yes	Yes

The financial input data and assumptions were obtained as a result of the literature review and industrial personal communication (Table 12). All those assumptions are based on conservative estimates and are possible to up actual estimation.

Table 12. Economic and Financial input data for Each Scenario

Items	**Unit**	**Scenario 1**	**Scenario 2**	**Scenario 3**
Well connection costs	$	$ 800,000.00	$ 800,000.00	$ 800,000.00
Delivery costs	$	$ 20,000.00	$ 25,000.00	$ 40,000.00
Gross plant size	kWe	120	250	300
Plant costs	$/kW	$ 2,866.67	$ 2,100.00	$ 2,400.00
	$	$ 324,000.00	$ 500,000.00	$ 680,000.00
Installation costs	$	$ 350,000.00	$ 350,000.00	$ 350,000.00
Total installed costs	$	$ 1,400,500.00	$ 1,675,000.00	$ 1,870,000.00
Landowner	%	12.50*		
Federal incentives	%	30		
Operating expenses	$/kWh	0.05		
Debt financing	%	50		
Interest rate	%	7.0		

* Data retrieved from Energy of North Dakota website, 2019

If a private tax-paying entity owns the geothermal project, the company can benefit from the tax exemption for the first five years. The exemption is applied only during the five years following installation. System owners must contact their local tax assessor or county director of tax equalization to apply for this exemption (North Dakota Renewable Energy Property Tax Exemption). Comparatively, if the state and the federal government owns the project, they are not required to pay taxes. Therefore, government ownership of the geothermal power system means they would not be required to pay taxes for the project’s lifetime (U.S. Department of Energy).

ECONOMIC RESULTS AND DISCUSSION

Based on the project economics and assumptions, the variation of conversion efficiency within the ORC systems, I described the analysis of the power plant scenarios and the economic analysis results below.

Economic Analysis Results

The results of scenarios 1-3 (Table 13) looked promising for further development, due to insufficient flow rates and rapid heat loss, the project has a high risk of failure. However, I assumed that heat sources remain constant over the project's lifetime.

Theoretically, all three scenarios show that the year-one cost of energy ranges from 10.95 to 19.15 ¢/kWh, which is more economical than the 28 ¢/kWh produced by diesel generators. The diesel generators are widely used in the current oil fields in the Williston Basin. The long-term diesel generator usage may not be environmentally friendly and have adverse effects on human health and the environment. However, the geothermal power development option would have a positive impact on the environment.

The results show that if a geothermal power development financing rate of return for the investors is 15%, the three scenarios simple payback time is approximately five to six years, based on a power sale price of 10 ¢/kWh.

For scenario 1, the payback is approximately six years based on a power sale price of 10 ¢/kWh. The LCOE is approximately 19.15 ¢/kWh, which is higher than the 2019 North Dakota industrial electricity purchase rate in Williston of 6.31¢/kWh (ND

Electricity Local, 2019). Therefore, this electricity price is likely not acceptable considering that the power purchase agreement rate would be 1 – 2 ¢/kWh above the LCOE.

For scenario 2, the payback is approximately five years, and the LCOE is approximately 11.45 ¢/kWh. This price is still higher than the 2019 ND power purchase rate, but it might be acceptable if other investments are available, such as grants or governmental support.

For scenario 3, the payback is approximately five years, and the LCOE is approximately 10.95 ¢/kWh. Again, this price is still higher than the ND power purchase rate. However, scenario 3 is the most economical in comparison to scenarios 1 and 2.

At this stage, the development of geothermal power systems in the current Bakken production fields is an unlikely economical option. This is due to insufficient production flow rate, rapid heat loss, and uncertainty of the technical viability.

Table 13. Results of Economic Analysis

Scenario	**Gross ORC size (kWe)**	**Net ORC size (kWe)**	**Annual Operation Expenses**	**System costs with incentives**	**LCOE (¢/kWh)**	**Simple payback (yrs.)**
1	120	108	$ 17,897.81	$ 1,427,267.50	19.15	6
2	250	225	$ 35,511.53	$ 1,613,197.00	11.45	5
3	300	270	$ 42,613.83	$ 1,817,947.00	10.95	5

CONCLUSION

This project aimed to evaluate the economic feasibility of generating electricity via binary technology in the active Bakken fields in western ND. Additionally, the study focused on utilizing coproduced fluid in oil fields and existing infrastructure. The development of a geothermal power system in oil and gas wells in western ND is inadequate via binary technology. The Parshall and Sanish Bakken are well-developed fields where flow rates are insufficient to run the Calnetix units, Climeon modules, or ENO units in the designated 2.5-mile radius area. On the other hand, the rapidly developing Banks Bakken field theoretically could provide enough fluid volume in the designated 2.5-mile radius area.

The Bakken Formation has shale with low porosity and permeability. To increase the fluid flow rate, the horizontal wells need to be fractured. However, even if the wells are fractured, an individual well in the multi-well pads will have insufficient fluid volume. The wells flow rates would still only range from 0.4 to 0.6 l/s per well. However, the current hydraulically fractured Bakken wells are not capable of producing adequate fluid flow rates for geothermal power generation. In addition to the low flow rate, the finite-difference model illustrates that the fluid temperature drops from 135 to 64 °C at the surface within the first year of the project. Although the continuous heat flow does not change over time, the flow rate is unlikely capable of sustaining the ORC systems. One option would be to drill the directional open-hole wells into the Red River or Madison Formations, which have a high enough formation temperature. If the electric submersible pumps (ESP) were installed, and those wells were pumped for water, they could economically generate power. While this is a big assumption, this scenario would have a high possibility of success.

Theoretically, based on the Banks Bakken #2 study area data, the optimistic Bakken temperature was 143°C and had a sufficient flow rate at 25 l/s. The thermal energy calculation and results of this theoretical economic analysis show that the Calnetix units, Climeon modules, and ENO units electricity generation costs 11.45, 10.95, and 19.15 ¢/kWh, respectively.

As a final point, due to the insufficient flow rate of a single well in the multi-well pads and rapid heat loss, it is uneconomical to develop the geothermal power plants through current Sanish, Parshall, and Banks Bakken multi-well pads in the western ND.

RECOMMENDATIONS AND FUTURE WORK

Investors will often be more interested in repurposing oil and gas wells in the western ND with the existence of higher temperature resources in the more permeable and deeper formations that have sufficient flow rate.

Future studies may focus on sedimentary Enhanced Geothermal System (EGS) development in the Williston Basin. A novel alternative approach could produce sufficient temperatures and flow rates for 100s of MW of power. The future approach would be to drill horizontal open-hole 8-inch (0.2m) water wells into the carbonate and sandstone formations at a depth of the Deadwood and Red River formations. These high permeable formations can yield a significant amount of fluid flow rates at approximately 50 l/s or higher per well, bottom-hole temperatures are at greater than 150 °C (Will

Gosnold et al., 2013). The Deadwood formation's approximate depth is 4 km (2.5 mi), with a thickness of 76.2 m (250ft), an average permeability that ranges from 3.3 mD to 72.3 mD, and an average porosity range from 2.6% to 10% (Fischer et al., 2008). For example, four wells drilled into the Deadwood formation could produce a total flow rate of 200 l/s and a temperature of 150°C. According to thermal energy, Eq.3 calculation shows that the Calnetix 125 MT Thermapower® ORC could produce power ranging from 16 to 17 MWh. The result is based on many assumptions, and further detailed study would be required.

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