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The Potential for Binary Geothermal Power in the Williston Basin

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ABSTRACT

Developments in organic Rankine cycle (ORC) technology, greater concentration of fluid volume through infill horizontal drilling, and greatly reduced drilling costs offer a positive outlook for co-production of geothermal energy in oil and gas fields. These developments coupled with knowledge gained from the University of North Dakota-Continental Resources (UND-CLR) binary geothermal power plant indicate that generating electricity with co-production and by drilling lateral geothermal wells would be economical in the Williston Basin. Evaluation of average fluid production, thermal energy, and electrical energy for five Bakken oil fields indicates that they could generate from 2.5 kWh to 3 MWh of electrical energy depending on the type of ORC system. Our analysis of the potential for power generation with the current volumes of fluid produced in the Bakken fields makes a strong case for geothermal development that could supply the demand for 2.6 GW of new power needed for oil field operations. Further geothermal development could occur as Bakken production declines and a new geothermal electric power industry could use the existing infrastructure to drill new deep lateral water wells modeled after the UND-CLR power plant. Bakken temperatures at depths of 3.0 km to 3.5 km range from 100 ºC to 144 ºC and temperatures in deeper (4.5 km to 5.0 km) formations reach 150 ºC to 160 ºC.

1. Introduction

The promise of capturing the thermal energy contained in oil field fluids appeared as a minor but plausible electrical power resource with the development of small (~250 kW) organic Rankine cycle engines in the early 2000s. At that time, analysis of the energy available from co-production in oil and gas operations gave a range of 9.44×10^{16} to 4.51×10^{17} J based on produced fluid temperatures of 100 ºC to 180 ºC (Tester et al., 2006). Assuming 2.78×10^{-7} J per kWh and a 6 percent efficiency binary power conversion system, the potential for electrical energy would lie between 1.57 TWh and 7.52 TWh. This is a significant amount of electrical energy, but more than a dozen years after Tester et al. (2006), the promise of geothermal power development using oil field fluids remains unrealized. Analysis of the reasons for lack of progress in harnessing that energy pointed to the combination of unfavorable economics and requirements for large-scale infrastructure necessary to generate tens of MW (Williams, Snyder, and Gosnold, 2016). The critical factors constraining economics are the low temperatures in sedimentary basins, typically less than 150 ºC, and the consequent requirements for inherently inefficient binary power conversion systems and flow volumes of about 1000 gpm (63.1 s^{-1}). Total fluid production and the water/oil ratios differ among and within sedimentary basins, but in most oil and gas fields scattered well spacing and low fluid volume production per well preclude concentration of large fluid volumes. The reality of oil field operations is that adequate well density rarely occurs and total fluid volumes even in closely spaced wells fall far short of 63.1 s^{-1}. For, example, the density of conventional, vertical, wells penetrating all oil producing formations in the Williston basin between longitudes 100 W and 104 W and latitudes 46 N to 49 N (124,300 km^2, n=12,657) averages about 0.1 km^{-2}.

Although this outlook seems discouraging, developments in organic Rankine cycle (ORC) technology, greater concentration of fluid volume through infill horizontal drilling, and greatly reduced drilling costs offer a more positive outlook. These developments coupled with knowledge gained from the University of North Dakota – Continental Resources (UND-CLR) binary geothermal power plant indicate that generating electricity with co-production and by drilling lateral geothermal wells would be economical in the Williston Basin. In studies conducted as part of research leading up to the UND-CLR installation, UND's team estimated that 4.0×10^{19} J of energy is available to produce 1.36×10^{9} MWh of electric energy (Gosnold, Mann, and Salehfar, 2017). In the following sections, we discuss the progress of binary geothermal power research for the Williston Basin, and we report analyses of the potential for co-production in several oil fields. A companion paper, Vraa et al., (2019), analyzes the economics of co-production and shows that approximately 25 percent of existing multi-well pads could become energy independent.

2. The UND-CLR Model

The UND-CLR power plant takes full advantage of existing infrastructure, and in that capacity demonstrates the technical and economic feasibility of generating electricity in oil and gas fields (Gosnold, Mann, and Salehfar, 2017). Although the power plant, which was designed to generate 250 kWh with two Thermapower ™ 125 XLT ORC engines, operated for only two days due to frost damage, all other aspects of the system met expectations. The geothermal water supply for the UND-CLR power plant comes from two open-hole lateral wells drilled into the 105 ºC Lodgepole Formation as part of a water flood project for secondary oil recovery from the Red River Formation. The well diameters are 8.75" (0.22 m) in the lateral sections. The tubing in the vertical sections is 4.5" (0.11 m) dia. The lateral lengths are 1.29 km at 2.3 km depth and 0.85 km at 2.4 km depth. Water temperature for water supply well, Davis 44-32, is 103 ºC at the wellhead and 98 ºC after flow through an uninsulated 400 m long pipe buried two meters below surface. We assume that similar temperatures exist for the deeper well, Hegge 43-46, but we did not visit the wellhead. Geothermal fluid flow in Davis 44-32 is 28 l s^{-1} and flow in Hegge 43-36 is 53 l s^{-1}. The hot water flows through the ORCs before it enters the injection plant. Thus, cooling of the water in the ORC benefits CLR by reducing heat stress on components of the injection pumps. The hydrostatic head for the Lodgepole Formation is at the ground surface and electric submersible pumps positioned at ~ 750 m depth in vertical sections have resulted in no drawdown of the fluid resource. The CLR water flood project includes five wells with a total water production rate of 124 l s^{-1}.

2.1 Advances in Binary Technology

The efficiencies of ORC systems in the early 2000s typically reached 6 percent for conversion of heat to electrical energy with most units designed to generate 50 kW to 250 kW. A significant advance in technology occurred with development of Calnetix's Thermapower ™ 125 XLT in 2013. Calnetix's system reduces parasitic energy loss using magnetic bearings and eliminating the turbine-to-generator gearbox with magnets in the turbine blades. The Thermapower ™ 125 XLT was specially designed for the UND-CLR binary power plant as a modification of their 50 kW ORC that requires 130 ºC fluid. The modified ORC uses fluid temperatures as low as 95 ºC, and its efficiency ranges from 7.1 percent for 100 ºC fluid to 11.1 percent for 138 ºC fluid. Analysis using the NREL Cost of Renewable Energy Spreadsheet Tool (CREST) on the operating parameters for the UND-CLR binary power plant generating 250 kW showed that Calnetix system rate would be 4.45 ¢/kWh and the nearest competitor rate would be more than 6.05¢/kWh (Gosnold, Mann, and Salehfar, 2017). Average electricity rates in the region for industrial, residential and commercial use are 6.31 ¢/kWh, 8.28 ¢/kWh, and 7.73 ¢/kWh respectively. These results suggest geothermal development would be economical. However, the water supply comes from wells drilled by CLR at a cost of $2M -$4M each and did not figure into the analysis. Including drilling costs in the CREST model would nearly double the cost of electricity even with the high efficiency Thermapower ™ 125 XLT. Even so, the LCOE would only be about the 8 ¢/kWh.

Fortunately, advances in technology continue (Figure 1), and the modular system now in production by Climeon (https://climeon.com/geothermal-plants/) can increase power production by a factor of 2 to 4 over other systems using the same fluid flow and temperature. The proprietary technology in the Climeon system yields high efficiency with only 4 kW of parasitic load for producing 150 kW per module. The large increase in power output is achieved using a modular system that cascades the geothermal fluid in 10 ºC steps. Geothermal fluid input of 30 l s^{-1} at 100 ºC cascaded through three 150 kW modules yields a total output of 450 kW. In theory, with the UND-CLR parameters of 98 ºC at 53 l s-1, the Climeon system could generate 779 kW. The Calnetix system uses a single pass of geothermal fluid to generate 250 kW, but there is no apparent reason that those systems could not also be cascaded.

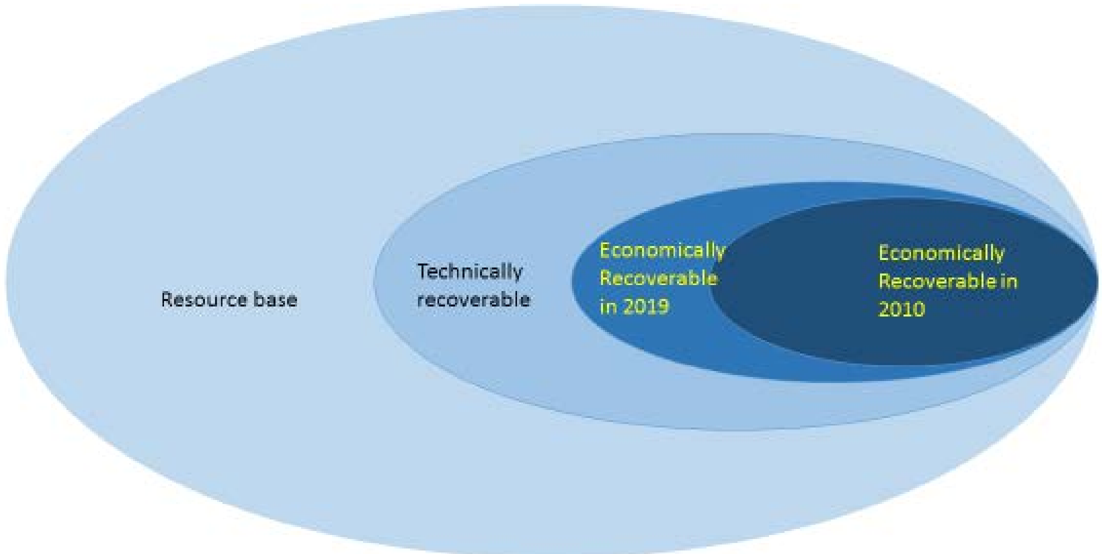

Figure 1: Visualization of the effect of technology on geothermal development.

2.2 Advances in Drilling Technology and Total Fluid Production in Multi-well Pads

Along with improvements in energy conversion technology, the development of multi-well pads and robotics in drilling have greatly reduced drilling costs. According to XTO Energy, Inc. (A. Huskey, pers. comm.) costs for a 3 km deep X 3 km horizontal Bakken well have decreased from more than $9M to about $2M. The effect of multi-well pads is a major factor because much of the drilling expense for new wells is at the surface. Having the infrastructure already in place eliminates most of that cost. Of further significance for geothermal development is that infill drilling from multi-well pads in the Williston Basin has increased the total fluid volume in some fields to levels that would be economic for binary power generation.

2.3 Current Outlook

We have begun a new assessment of geothermal power potential for all of the Williston Basin and here we present our initial analysis of five oil fields in the Bakken and Three Forks formations. A map of all oil fields from the North Dakota Industrial Commission (NDIC) Oil & Gas website, Figure 2, shows active rigs on March 11,/2019 (green towers) and oil field boundaries (red lines) in the Williston Basin. This analysis uses the total flow, oil and water, for each field for estimation of electricity generation using the 125 kW Calnetix ORC and the 150 kW Climeon ORC. This broad-brush approach carries the assumption that fluid production can be combined through pipe networks that would supply adequate volumes for maximum production from the ORCs. A companion paper, Hertz et al., (2019), addresses economics for use of multi-well pads where flow volume would be used on site with smaller 20 to 25 kW ORCs.

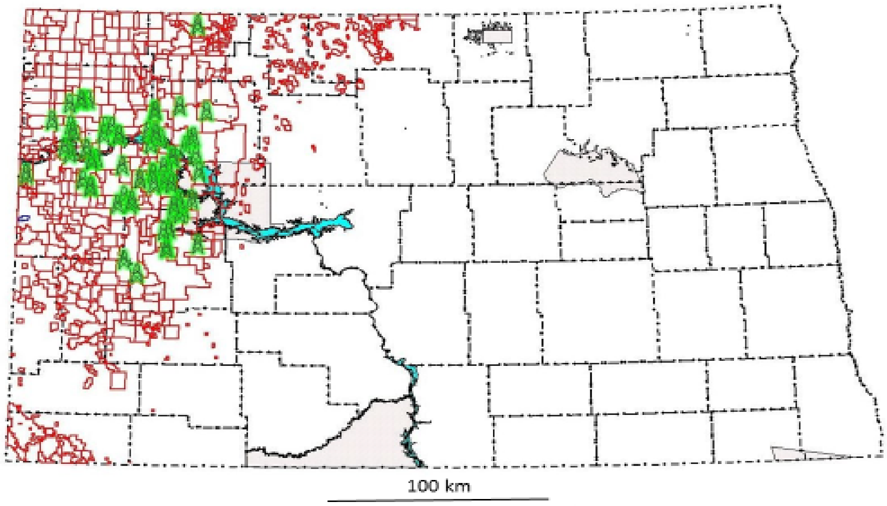

Figure 2. Map of North Dakota showing county boundaries, oil field boundaries – red lines, and active drilling rigs – green towers on March 11, 2019.

Figures 3 – 7 show maps that include the five Bakken &Three Forks fields we have analyzed. Each of the five fields is outlined in gold on the maps and all fields are identified by black text in yellow highlighting. Producing wells are identified by black dots and lateral well paths are shown by black lines.

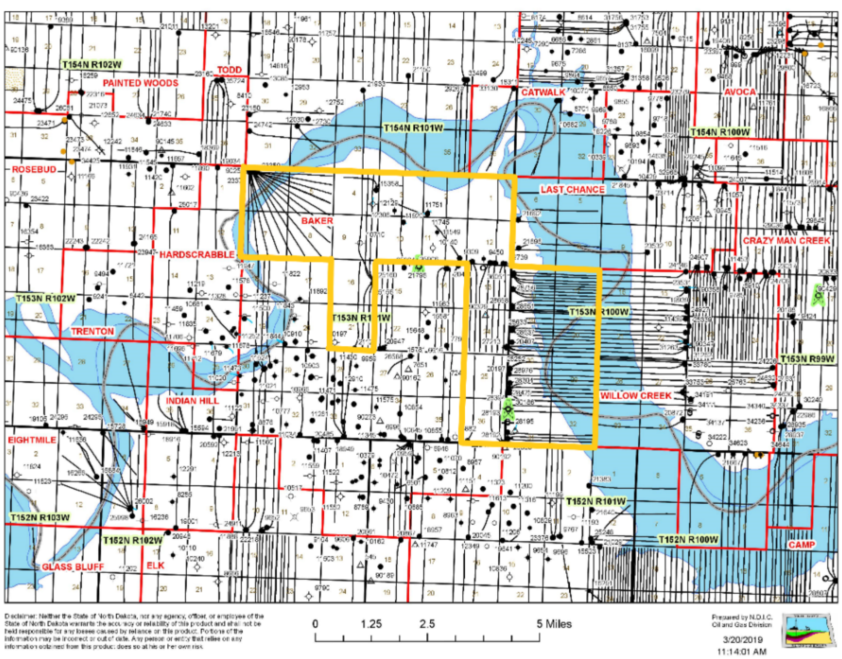

Figure 3. The Baker Bakken field comprises 67 wells producing an average of 11.6 l s^{-1} water and 5.8 l s^{-1} oil for the past 2 years. Average temperature is 126 ºC.

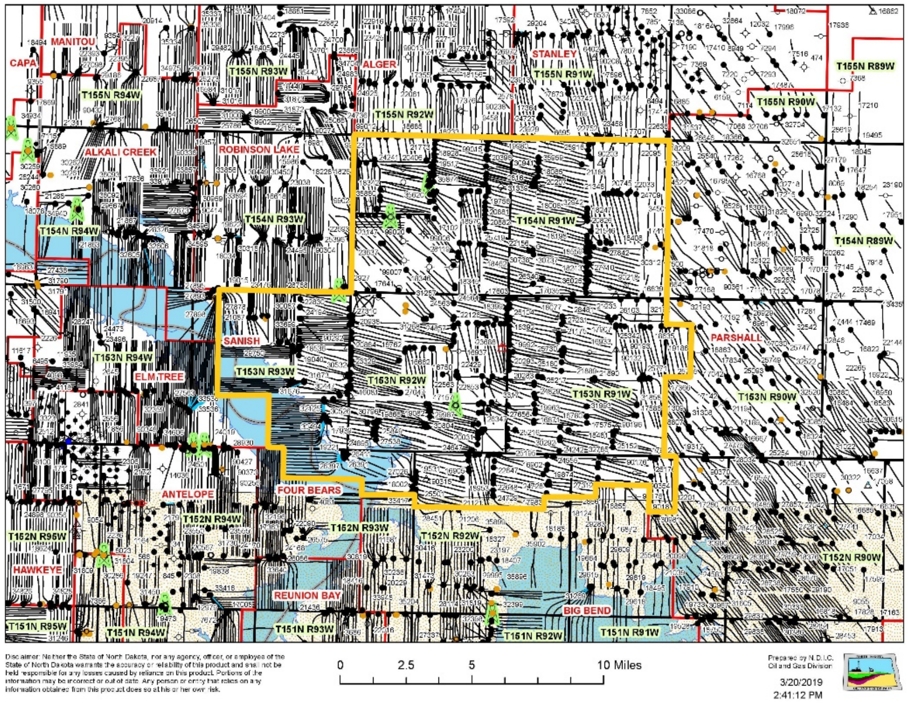

Figure 4. The Sanish Bakken field comprises 647 wells producing an average of 63.1 l s^{1} water and 82.2 l s^{-1} oil for the past 2 years. Average temperature is 114 ºC.

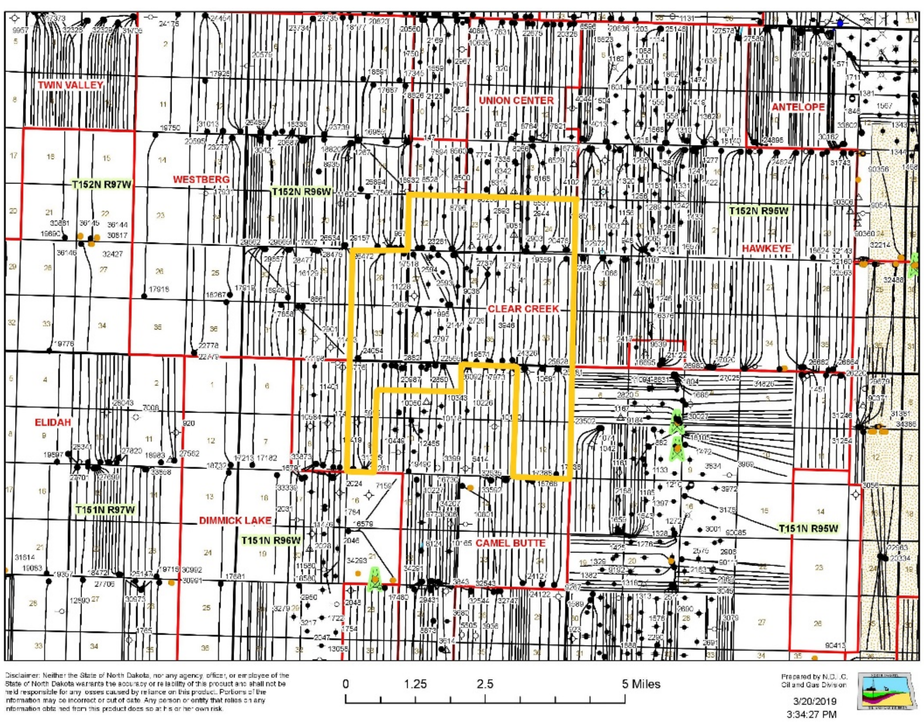

Figure 5. The Clear Creek Bakken field comprises 77 wells producing an average of 3.5 l s^{-1} water and 8.4 sl s^{-1} oil for the past 2 years. Average temperature is 143 ºC

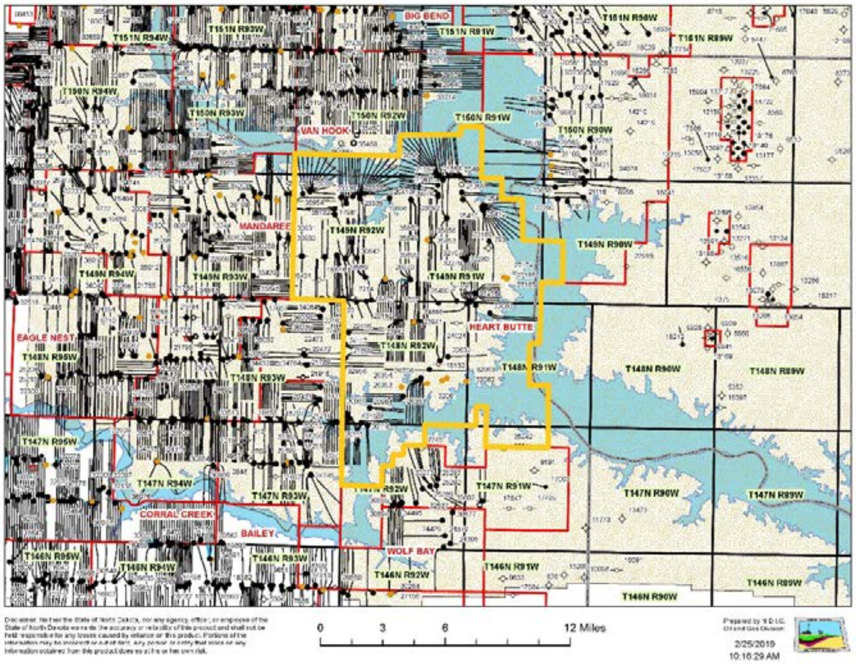

Figure 6. The Heart Butte Bakken field comprises 209 wells producing an average of 44.1 $l\ s^{-1}$ water and 36.50 $l\ s^{-1}$ oil for the past 2 years. Average temperature is 112 ºC.

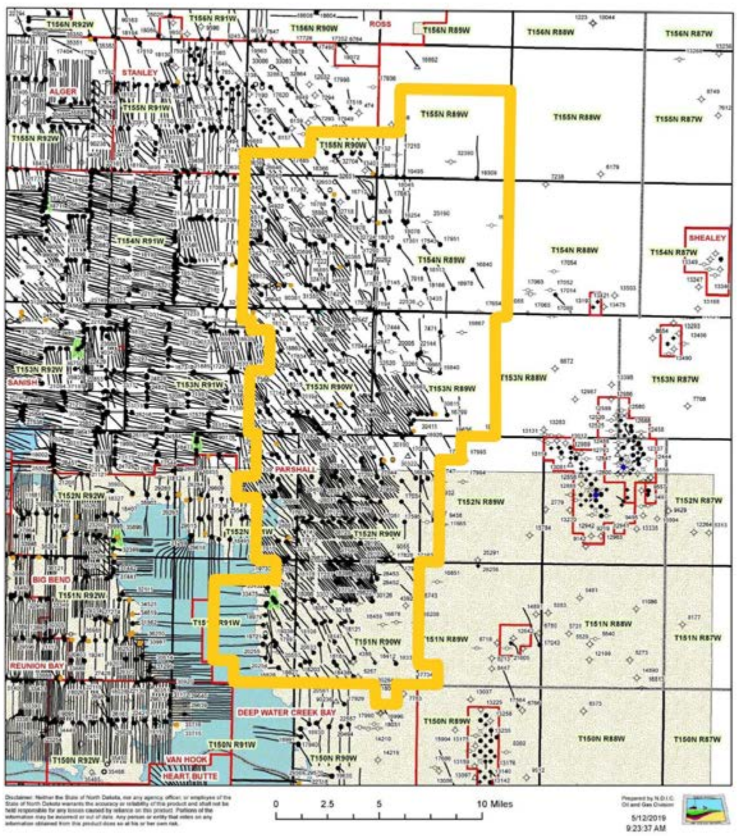

Figure 7. The Parshall Bakken field comprises 483 wells producing an average of 62.7 $l\ s^{-1}$ water and 72.0 $l\ s^{-1}$ oil for the past 2 years. Average fluid temperature is 100 ºC.

Average fluid production, thermal energy, and electrical energy for these five Bakken oil fields could generate from 4.5 MWh to 7.9 MWh of combined electrical energy depending on the type of ORC system (Table 1). We calculated energy from the averages for oil and water from $E = \rho V c_v \Delta T$ where ρ is density, V is volume, c_v is heat capacity, and ΔT is temperature drop. We converted thermal energy to electrical energy using 2.78×10^{-07} kWh J^{-1}. Temperatures in the Bakken Formation for the fields examined range from 110 ºC to 143degC, and the ΔT was calculated as the difference between the formation temperature at each field and an assumed outlet temperature of 70 ºC. Different physical and thermal parameters for oil and water as described in Table 2 were used in the calculations. Analysis of energy production used an efficiency for the Calnetix Thermapower XLT that varies with temperature, ranging from 9.4% to 14.1% based on the relationship Calnetix provided for the UND-CLR demonstration project, while the Climeon system has a constant efficiency of 14% across the relevant temperature range.

Including differences for efficiency, the cascade feature of the Climeon system can produce more power than the single pass Calnetix system. However, it may be possible to cascade the Calnetix system as well.

Table 1. Calculated energy production from five Bakken fields in the Williston Basin. ORC#1 is for the Calnetix system and ORC# 2 is for the Climeon system.

Field	No. Wells	Oil ($l\ s^{-1}$)	Water ($l\ s^{-1}$)	Energy (J) #1	Energy (J) #2	kWh ORC#1	kWh ORC#2
Baker	67	5.8	11.6	1.78E+06	2.96E+06	240	414
Clear Creek	72	8.4	3.5	8.53E+05	1.42E+06	115	199
Heart Butte	200	36.5	44.1	7.44E+06	1.24E+07	1,005	1,736
Parshall	467	72	62.7	1.15E+07	1.92E+07	1,558	2,693
Sanish	620	82.2	63.1	1.21E+07	2.01E+07	1,631	2,818

Table 2. Density and heat capacity for oil and water used in calculations.

Fluid	ρ ($kg\ m^{-3}$)	c_v ($J\ kg^{-1}\ K^{-1}$)	ΔT #1	ΔT #2
Oil	870	1830	30	50
Water	1030	4181	30	50

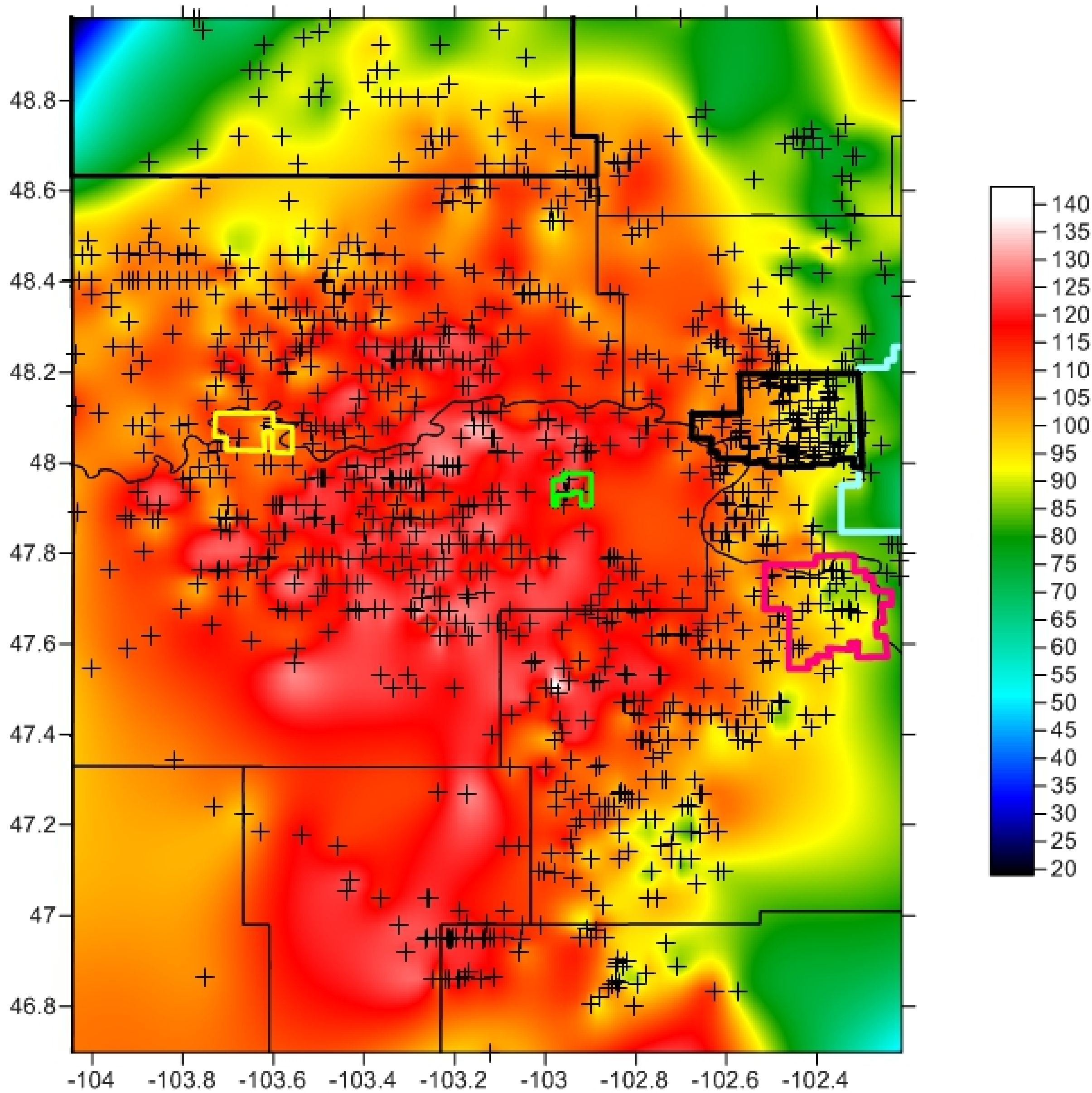

Figure 8. Temperature (ºC) contour map of the Bakken Formation derived from BHT data. Plus signs show locations of BHT data. Colored polygons show the five Bakken fields: Yellow-Baker. Green-Clear Creek, Red-Heart Butte, Black-Sanish, Cyan-Parshall.

Fluid production over time in all fields rose almost exponentially with the rising price of oil until mid-2014. Since then, production volume has varied differently in the fields with some appearing to show decline and some not, Figures 8-12. In general the volume of fluid per well has declined in all fields and it seems prudent to speculate on future production volume. The decline was probably due to a combination of factors including: oil price, drop in active drilling rigs, increase in water cut, and to the nature of the Bakken Formation. The pay zone for the Bakken is a very tight reservoir with poor porosity and ultra-low permeability. Most production is still in primary oil recovery stage with gas expansion as the driving mechanism. Thus, reservoir pressure decrease and oil price do appear to control the observed decline in fluid volume.

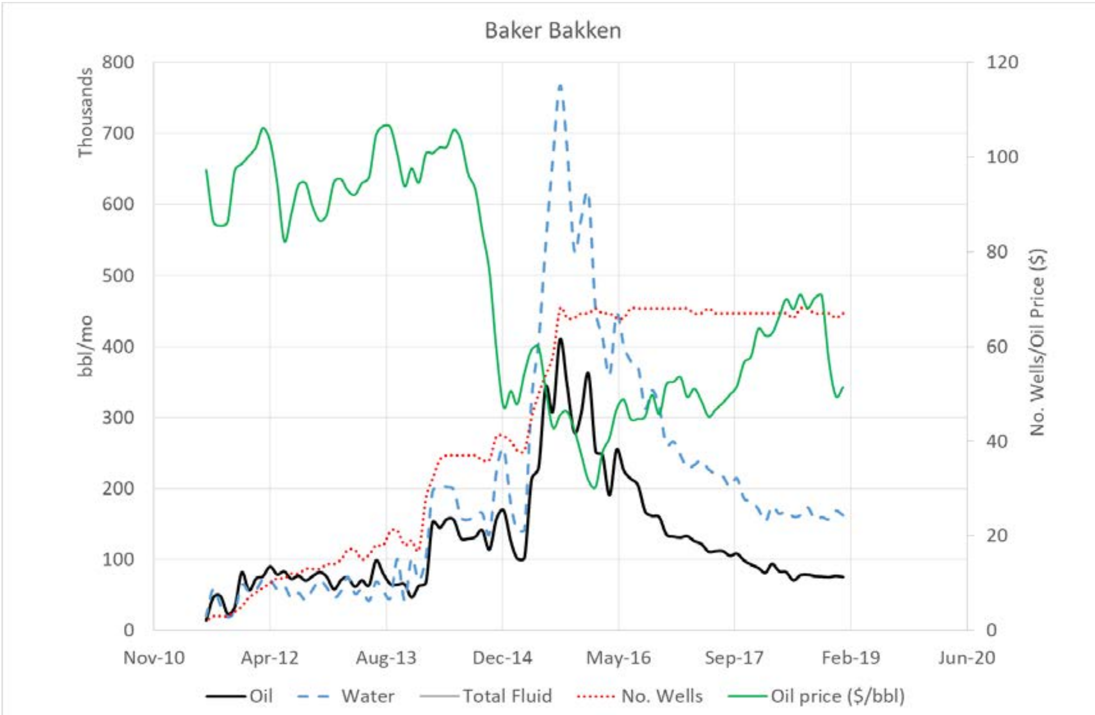

Figure 9. Production chart for the Bakker Bakken field.

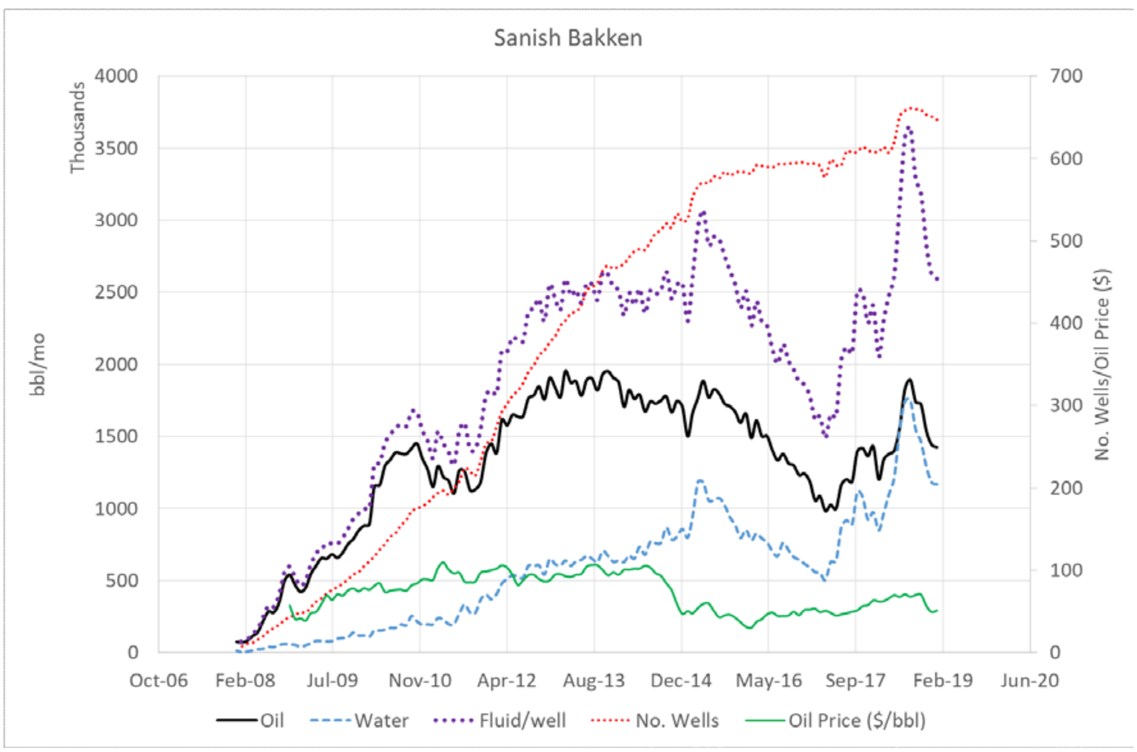

Figure 10. Production chart for the Sanish Bakken field.

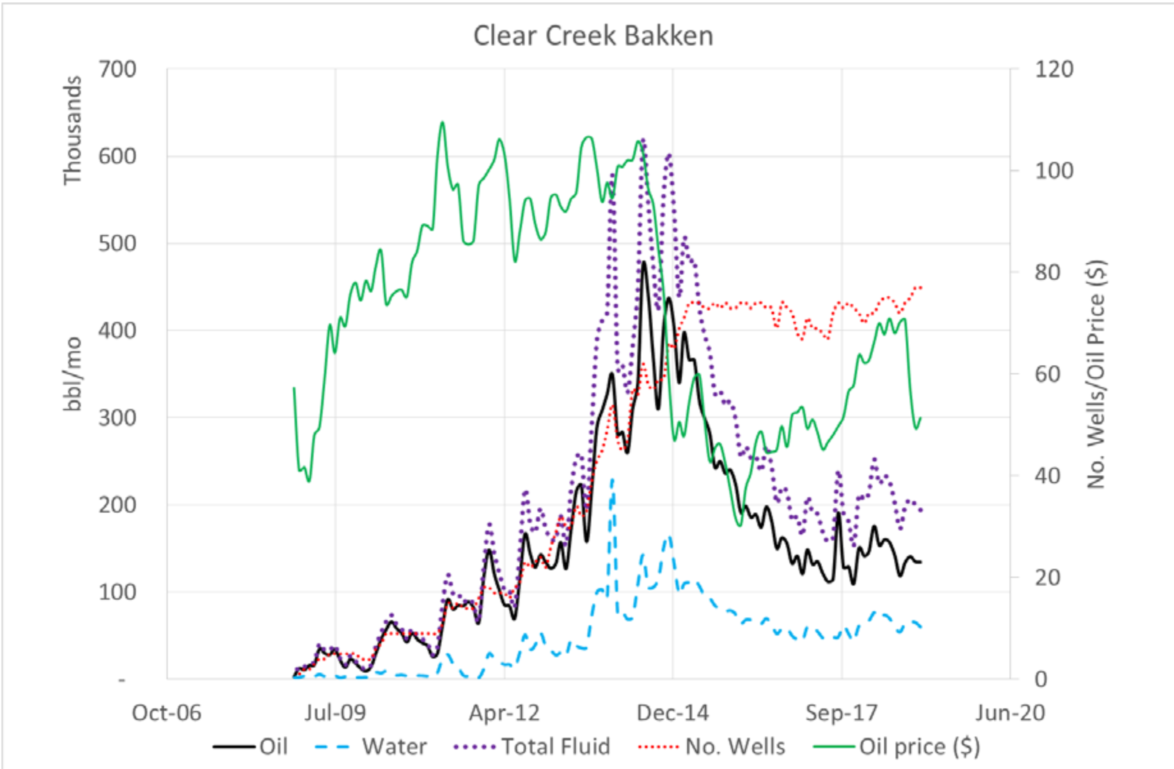

Figure 11. Production chart for the Clear Creek Bakken field.

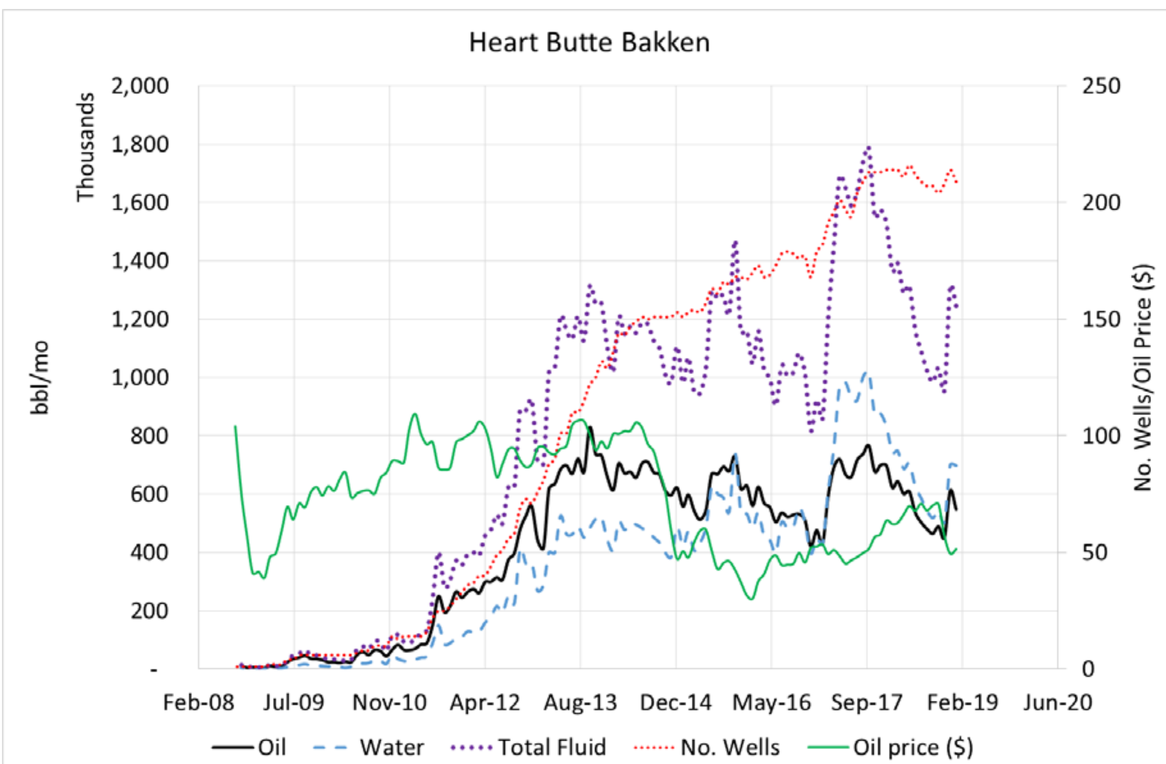

Figure 12. Production chart for the Heart Butte Bakken field.

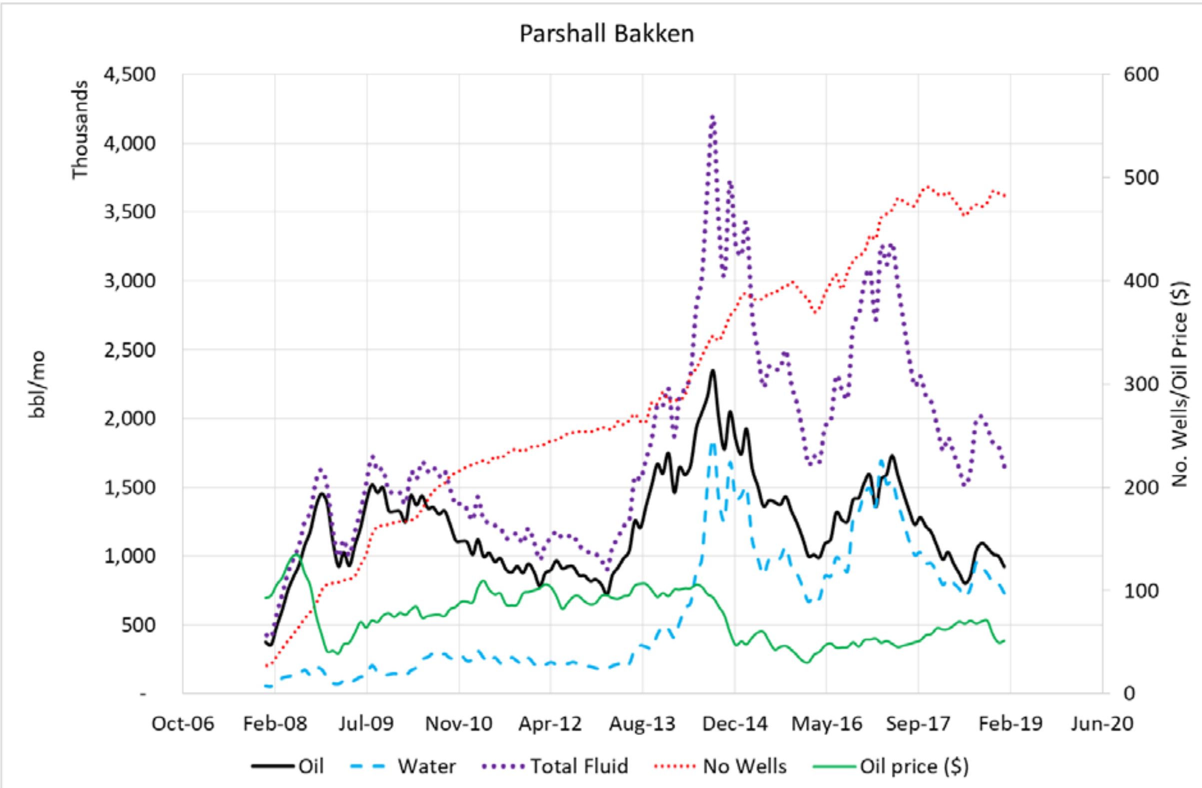

Figure 13. Production chart for the Parshall Bakken field.

2.3 Implications for Future Geothermal Development

Although production decline is real and expected, the extreme changes in oil price from \$40 per bbl to \$110 per bbl and back to \$50 per bbl make for a highly unreliable production time series. Three critical factors for the future that we consider are:

1) The North Dakota Industrial Commission (NDIC) estimates that 2.6 GW of additional electrical power will be needed to produce the remaining oil in the Bakken and Three Forks Formations;

2) There is no power line infrastructure to the Bakken fields and producers are using propane, diesel, and gasoline powered electrical generators to pump oil;

3) T significant improvement in binary power plant technology in conjunction with the production from multiple horizontal wells from the same surface location results in a significant improvement in the economics of geothermal power generation using co-produced fluids..

4) The reality of extreme weather disasters due to fossil fuel burning will dawn on enough people to cause change and the transition to renewables will occur.

3.0 Conclusions

Our analysis of the potential for power generation with the current volumes of fluid produced in the Bakken fields coupled with the first two factors makes a strong case for geothermal power development. Although it may appear that the third factor presents a contradictory argument, the reality is that the transition will occur at a manageable pace and the Bakken – Three Forks oil production will eventually decline to non-economic levels. We propose that as multi-well fields decline, the geothermal electric power industry can use the existing infrastructure to drill new deep lateral water wells modeled after the UND-CLR power plant. According to A. Huskey, XTO Energy, Inc., most of the cost of drilling is at the surface, thus use of existing infrastructure improves economics. Targeting the deeper formations with multiple lateral geothermal wells in a 2, 6, or 8 fold array from a single pad or in an EGS configuration would offer opportunities for 10s of MW per site. Bakken temperatures at depths of 3.0 km to 3.5 km range from 100 ºC to 144 ºC and temperatures in deeper (4.5 km to 5.0 km) formations reach 150 ºC to 160 ºC.

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