Using Geothermal Energy to Reduce Oil Production Costs

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Keywords

Sedimentary basin geothermal, coproduction, oil field economics, binary power

ABSTRACT

The economic impact of the Covid-19 pandemic on the oil industry has been devastating. The decline in demand and price collapse have been particularly disruptive for shale oil extraction which is inherently more expensive than conventional operations. Survival and continuing operations will depend partly on reducing operating costs, and a ubiquitous and substantial cost in oil production is electrical power used primarily for pumping the wells. The Bakken in North Dakota play is particularly vulnerable because there is not an adequate electrical grid in the region. Many Bakken fields rely on generators burning propane, gasoline or diesel fuel at costs about \$0.28 per kWh - four times grid costs. Shale plays have the unique characteristic of multiple wells per pad so that the total fluid available can be enough for coproduction of 10s to 100s of kW with an ORC on site. Bakken temperatures range from 100 °C where heat flow is low (≈50 mW m^{-2}) and the Bakken is shallower on the eastern margin of the shale play to 140 °C where heat flow is higher (≈70 mW m^{-2}) and the Bakken is deeper in the center of the basin. Previous analyses of the potential for coproduction were based on total field and large multi-well pad production volumes and did not address fluid flow per individual well. Analysis of heat loss with 2-D and 3-D models indicates coproduction is not feasible because fluids in Bakken wells lose too much heat during the slow 3-km transit to the surface. Water-rich carbonate rocks underlying the Bakken have higher temperatures and could generate several MW of power at local sites. Three scenarios for the higher power operations include: 1) Recompleting marginally economic existing oil wells in the overlying Lodgepole Formation and converting to water production; 2) Installing ORCs on the many water flood projects in the basin; 3) Drilling dedicated well fields for geothermal power production. After use in the ORCs, the hot waters could be used for low-cost space heating and further reduction of energy costs. An average submersible pump requires 16 kW, so, for example, if an ORC generated 160kW it could supply enough electricity to pump 10 wells.

1. Introduction

The western half of the Williston Basin is an energy giant containing approximately 1,000 EJ of recoverable geothermal energy in permeable Paleozoic carbonate and sandstone rocks and 4.4 to 11.4 billion barrels of technically recoverable oil in the Bakken shale play. We have known of the geothermal resource for decades, but its development has been delayed for reasons which can be summed as economic competition from existing fossil fuel energy sources (Williams et al., 2016). In a twist of fate due to the collapse of oil prices and the impact of the Covid-19 pandemic on North Dakota shale operations, development of the geothermal resource could provide economic support for the shale operations by supplying low cost electrical power. Due to the remoteness of the Bakken play, there is not an adequate electrical grid system in the region and many Bakken fields rely on generators burning propane, gasoline or diesel fuel at costs about four times grid costs per kWh. We present four geothermal initiatives that could provide sustainable energy support for the Bakken fields: 1) Recompleting marginally economic existing oil wells in the overlying Lodgepole Formation and converting to water production 2) Installing ORCs on the many water flood projects in the basin; 3) Drilling well fields for geothermal power production; 4) After use in the ORCs, the hot waters could be used for low-cost space heating and many other direct use applications and further reduction of energy costs.

2. Geothermal and oil

Oil and hot water occur in many of the same sedimentary formations in the Williston Basin and much of the technology and infrastructure for extraction of both are shared. Most oil-bearing formations in the basin containing abundant water are considered regional aquifers (Downey, 1981, 1984, 2009). The Bakken Formation is an exception in that it is tight and cannot produce large quantities of water. Some of the carbonate rocks overlying and underlying the Bakken are known to produce several 10s of liters per second in water flood operations and have temperatures above 150 °C. Identifying the geothermal resources associated with oil and gas reservoirs is not so constrained by favorable geometry as is oil exploration. Geothermal waters in flat-lying sediments are essentially everywhere below a target isotherm and the essential data are temperature, depth, porosity and permeability. In the case of a well-explored sedimentary environment like the Williston Basin, there is a wealth of data, i.e., porosity and permeability data and bottom-hole temperatures that were acquired during oil and gas exploration. That information along with heat flow studies reveals the geothermal potential of the basin (Gosnold et al., 2016; Crowell, 2015; McDonald, 2015; Blackwell and Richards, 2004; Gosnold, 1991; Combs and Simmons, 1973; Blackwell, 1969).

2.2 Geothermal coproduction

Previous studies that evaluated the coproduction potential for several Bakken oil fields in the Williston Basin concluded that binary geothermal systems using the combined oil and water flow from single fields could generate hundreds of kW to a few MW of electrical power (Vraa et al., 2919; Gosnold et al., 2019). For those evaluations it was assumed that the combined fluid flow from multi-well pads could be concentrated in strategically spaced locations for use in individual binary power plants. Fluid production from the fields evaluated ranged from 100,000 bbl. per month (6 liters per second) to 1.5 million bbl. per month (91 liters per second). In situ temperatures were known to range from 100 °C in the Sanish, Parshall and Heart Butte fields to 140 °C in the Banks and Siverston fields.

After those studies were published, discussions with industry engineers regarding tapping the geothermal resource revealed the temperatures of the produced fluids were generally less than 70 °C - temperatures too low for even high-efficiency binary power systems. We were confident in the formation temperatures (Gosnold et al., 2012; McDonald, 2015), but apparently heat was being lost between the formation and the surface sites where temperatures were measured. We had assumed that although heat loss could be significant during the early weeks of production, heating of the rocks surrounding the production tubing should quickly diminish that heat loss to acceptable levels. Apparently, that was not happening, and further analyses of our data revealed the reason for the disconnect between model simulations and observations.

3. Heat Loss Analysis

The factors affecting heat loss from the production tubing are flow rate, temperature differences between the fluid stream and the encasing rock mass, thermal properties of the fluid and the rock mass, and the surface area of the pipe-rock contact. Flow rates in Bakken production vary significantly between wells and fields and over time. The Bakken is an unusually tight formation with permeabilities varying between 0.01 and 20 mD. Production requires hydraulic fracturing with 10s to 100s of fracks in the 2 mile (3.2km) lateral sections. Due to the tightness of the formation, production flow rates decline rapidly with as formation pressure drops after startup.

3.1 Bakken production rates

Data from August 2019, for 13,101 producing Bakken wells in North Dakota show a combined oil and water production rate of only 0.48 ± 0.89 liters per second per well. This is an unbalanced perspective in that 88 percent of the wells (11,516) average only 0.22 ± 0.19 liters per second. Some fields, e.g., Banks, have a high average production rates per well of 0.8 liters per second. But that is a "young" field which has yet to experience the normal production decline with age. A possible explanation for the simulation-observation disconnect is that while the total fluid flow per field could be tens of liters per second, the average flow per well is only a few tenths of a liter per second. Conceptually, significant heat loss could occur during the 3 km trip to the surface. In older fields, production typically declines by as much as 80% per well after startup. (Figure 1). Thus, even though initial flow may be greater than 1 liter per second, within a few months flow rates typically drop to about 0.2 liters per second. For example, the Baker field which has been operating since July 2011 and the number of wells operating has stabilized at 67 since September 2015. Total fluid production in the field declined from its peak of 71 liters per second in September 2015 to only 9.9 liters per second in February 2019. The decline in average flow per well was from 1.01 to 0.15 liters per second.

3.2 Numerical models

To understand and quantify the impact of the low flow rates on fluid temperatures at the surface, we developed a finite-difference numerical model of heat loss at different flow rates. The model configuration, Figure 2, permitted simultaneous testing of 12 different flow rates in a 3000 m vertical geological section typical of a Bakken field. The twelve vertical wells were spaced at 41-meter intervals to ensure thermal isolation between pipes. Each well-bore diameter was 8-inches (20 cm) with 4-inch (10 cm) tubing and the anulus was filed with cement. The 2-dimensional grid consisted of 500 vertical and 300 horizontal nodes. Horizontal node spacing in the hole and pipes is 2.5 cm and increases in expanding 2x increments to 8 m. Vertical grid node spacing was 6.25 m except for the upper 30 m which had 1-m spacing. Changes in grid spacing were limited to a factor of 2 to maintain thermal equilibrium during simulations. Thermal conductivities of the formations are 1.2 W $m^{-1}K^{-1}$ in the Cenozoic, 1.6 W $m^{-1}K^{-1}$ in the Mesozoic and 2.4 to 3.0 W $m^{-1}K^{-1}$ in the Paleozoic (Gosnold et al., 2012). Thermal conductivity of the cement grout is 0.6 W

$m^{-1}K^{-1}$. To make the model as accurate as possible for temperature differences between the fluid and the rock mass, we used a temperature-depth profile appropriate for the center of Bakken production (Figure 3). The temperature profile was calculated using Eq. 1 with heat flow values from the heat flow contour map of Gosnold et al., (2016), thermal conductivities from Gosnold et al., (2012), and formation thicknesses from Scout Ticket data from the North Dakota Oil and Gas website.

$$T = T_0 + \sum_{i=1}^{n} q \frac{L_i}{\lambda_i} \qquad \text{Eq. 1}$$

where T, T_0, q, L, λ are temperature at depth, surface temperature, heat flow, formation thickness, formation thermal conductivity, respectively.

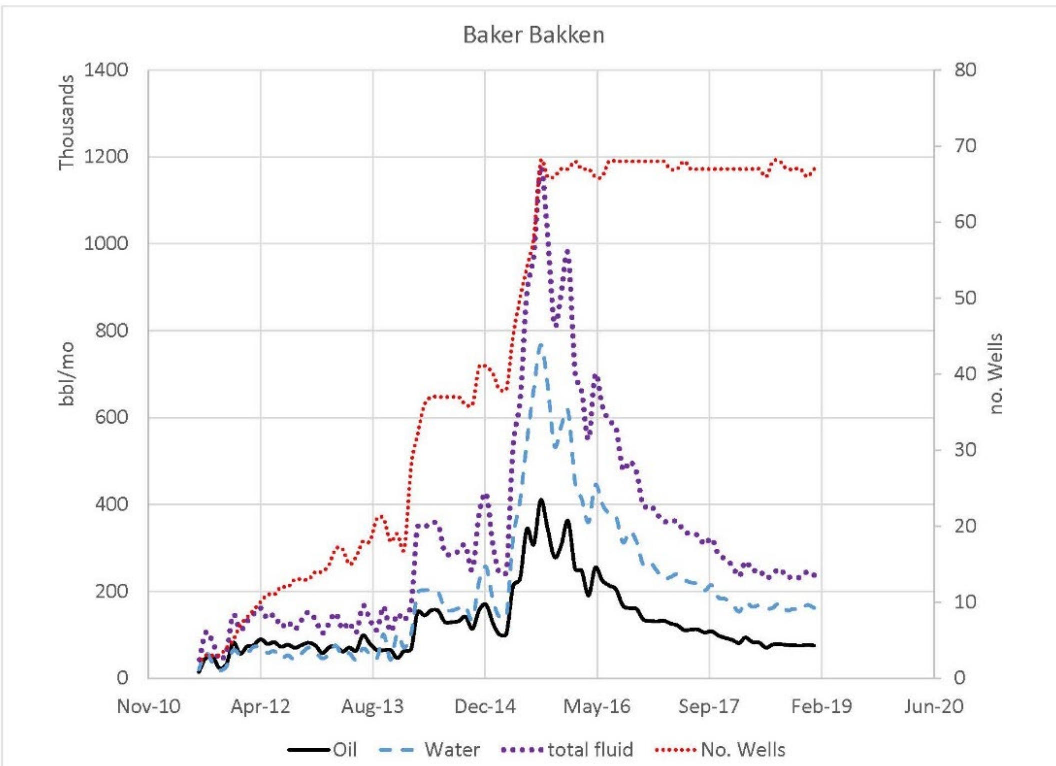


Figure 1. Monthly production data for the Baker Bakken field. Total fluid production declined from 70 liters per second in September 2015 to 0.1 liters per second by February 2019 once the number of wells had stabilized.

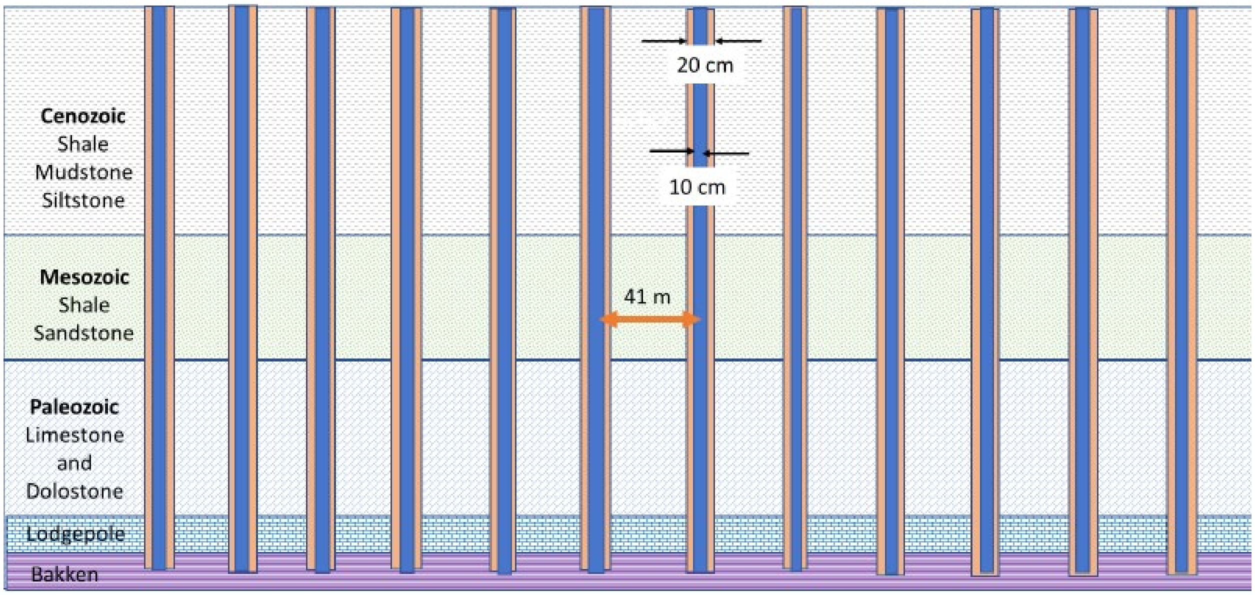
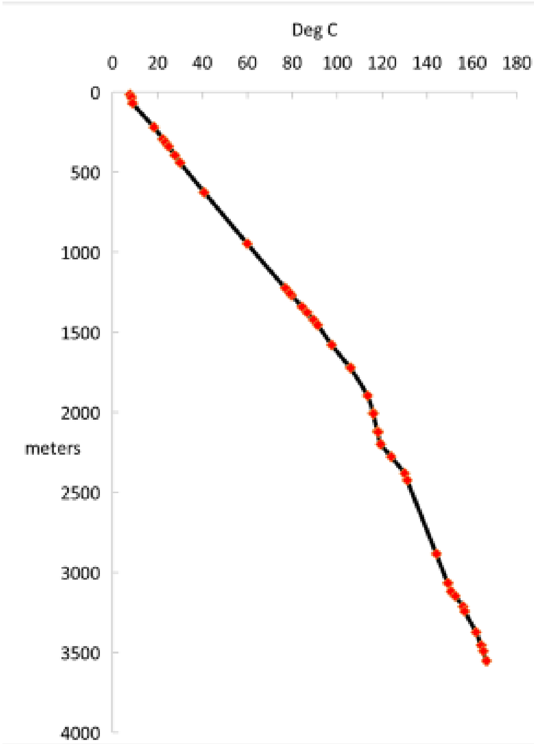


Figure 2. Model for evaluating heat loss in pipes. Vertical dimension is 3000 m and horizontal dimension is 740 m. The grid contains 500 vertical and 300 horizontal nodes. The twelve four-inch (10 cm) pipes are spaced at 41 m intervals. Hole diameter is 8-inches (20 cm), tubing diameter is 4-inches (10 cm) and the anulus outside the casing is filled with low thermal conductivity cement. Horizontal grid spacing in the hole and pipes is 2.5 cm and steps out in expanding increments to 8 m to isolate thermal effects for individual pipes. Vertical grid spacing is 6.25 m. Thermal conductivities of the formations are 1.2 W $m^{-1}K^{-1}$ in the Cenozoic, 1.6 W $m^{-1}K^{-1}$ in the Mesozoic and 2.4 to 3.0 W $m^{-1}K^{-1}$ in the Paleozoic (Gosnold et al., 2012). Thermal conductivity of the grout is 0.6 W $m^{-1}K^{-1}$.



Formation	Depth (m)	Formation	Depth (m)
Brule Fm	17	Minnekahta Fm	2,003
Chadron Fm	34	Opeche Fm	2,011
Golden Valley Fm	69	Broom Creek Fm	2,117
Tongue R. Fm	219	Amsden Fm	2,122
Slope Fm.	294	Tyler Fm	2,198
Cannonball Fm.	315	Otter Fm	2,277
Ludlow Fm	339	Kibbey Fm	2,381
Hell Creek Fm	395	Charles Fm	2,424
Fox hills Fm	440	Mission Canyon Fm	2,883
Pierre Fm	625	Lodgepole Fm	3,066
Niobrara Fm	1,225	Bakken Fm	3,119
Carlille Fm	1,270	Three Forks Fm	3,148
Greenhorn Fm	1,224	Bird Bear Fm	3,214
Belle fourche Fm	1,255	Duperow Fm	3,242
Mowry Fm	1,341	Souris R. Fm	3,373
Newcastle Fm	1,378	Dawson Bay Fm	3,453
Skull Creek Fm	1,423	Prairie Fm	3,492
Inyan Kara Fm	1,454	Winnepegosis Fm	3,553
Swift Fm	1,579	Interlake Fm	3,697
Rierdon Fm	1,720	Stonewall Fm	3,791
Piper Fm	1,723	Stony Mountain Fm	3,886
Spearfish Fm	1,894	Red River Fm	3,981

Figure 3: Calculated temperature vs. depth profiles and general stratigraphy for the center of the Williston Basin from Murphy et al., (2009). Temperature profile from Eq. 1 based on heat flow of 70 mW m^{-2}. Colors in the stratigraphic columns designate geologic eras: Sand shade – Cenozoic, green shade - Mesozoic, blue shade - Paleozoic. General compositions are siltstones and shales and sandstones for the Cenozoic and Mesozoic and dolomites and limestones for the Paleozoic.

2.1 Model Results

The first model runs simulated time periods of 1 day, 1 week, 1 month, and 1 year. Initial temperatures at surface and at 3-km were 10 °C and 115 °C. Flow velocities tested were 0.05, 0.1, 0.2, 0.3, 0.4, 0.5, 0.6, 0.7, 0.8, 0.9, 1.0, and 2.0 liters per second. Initial results showed that significant amounts of heat would be lost at slower flow rates during one week of flow before the encasing rock mass heated up. Simulations for one month and one year also indicated heat loss with slow flow, but the modeled heat loss over time was clearly as much as expected from the reports of measured temperatures, Table 1. A problem we soon recognized was that the model was too simple in that two-dimensional models are inadequate for simulating heat loss from fluid flow in pipes. Two-dimensional models treat the pipe as a flat rectangle with surfaces that include only the lateral sides, top, and bottom of the pipe. The front and back are essentially infinite and at ambient temperature so there is no heat exchange with the surrounding rock in half of the surface, object A in Figure 4. Thus, only half of the heat loss from the pipe can be simulated with a two-dimensional model. Three-dimensional models include the complete surface of the pipe,

Flow l s^{-1}	°C 1 d.	°C 1 wk.	°C 1 mo.	°C 1 y.
0.05	24.52	33.57	47.57	82.98
0.10	24.88	47.74	66.11	98.17
0.20	49.63	66.62	86.27	106.82
0.30	60.63	79.02	95.45	109.81
0.40	69.39	86.94	100.38	111.09
0.50	76.23	92.20	103.40	112.18
0.60	81.58	95.91	105.45	112.72
0.70	85.71	98.60	106.89	113.19
0.80	89.11	100.71	108.00	113.50
0.90	91.88	102.38	108.88	113.75
1.00	94.16	103.73	109.58	113.94
2.00	105.05	109.88	112.71	114.83

Table 1. Modeled wellhead temperatures at different flow rates after 1 day, 1 week, 1 month, and 1 year of flow from a 115 °C source.

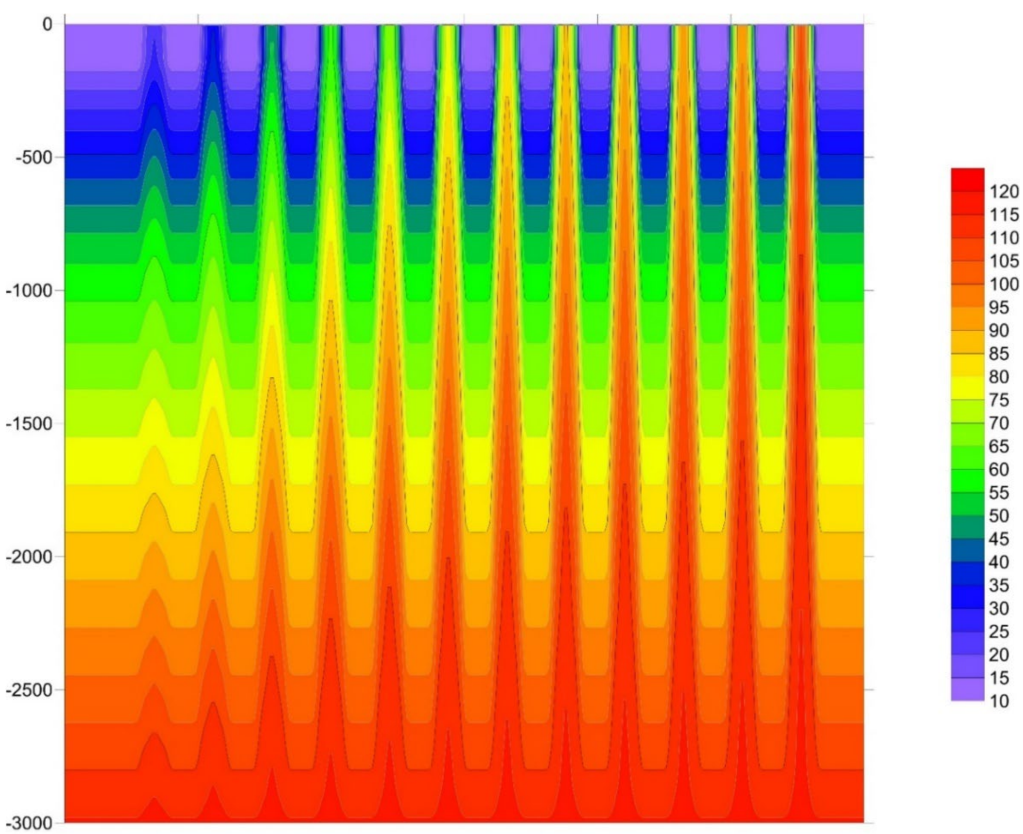


Figure 4. Simulated temperature contours in a 2-D model after one week of flow in 12 3-km vertical pipes at velocities of 0.05, 0.1, 0.2, 0.3, 0.4, 0.5, 0.6, 0.7, 0.8, 0.9, 1.0, and 2.0 liters per second.

The contours in Figure 4 give the impression of significant heat loss laterally from the vertical pipes, but this is an artefact of the contouring program which treats all points in the 300 x 500 grid as equally spaced nodes. The upper 30 vertical grid points are at 1 m intervals. From 30 m the spacing is 2. 4. 6, and 6.25 to 3000 m. The horizontal grid spacing across each pipe and cement grout is 0.025 m, and it steps up in increasing increments to 8 m halfway between the pipes. A more representative display of temperatures with actual spacing is given in Figure 5.

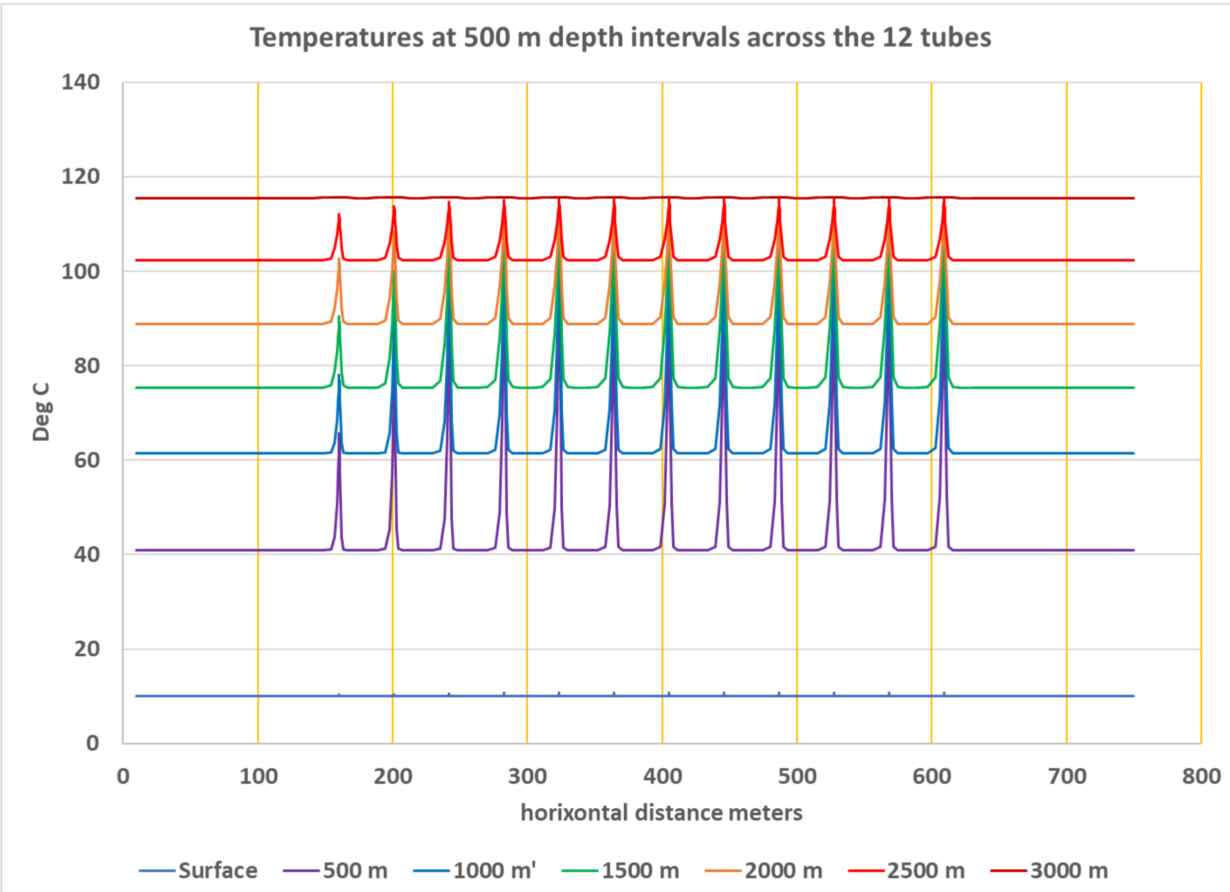


Figure 5. Temperatures at 500 m depth intervals with no horizontal exaggeration from the data displayed in Figure 4. This figure is to demonstrate the true spacing of the 500 horizontal points in the array. Any asymmetry in the diagram is an artefact of the graphical packages in Surfer and Excel.

Thus, we undertook a series of tests of numerical models of heat loss and gain by fluids flowing in pipes indicate that pipe size, model geometry. and dimensions significantly affect model results.

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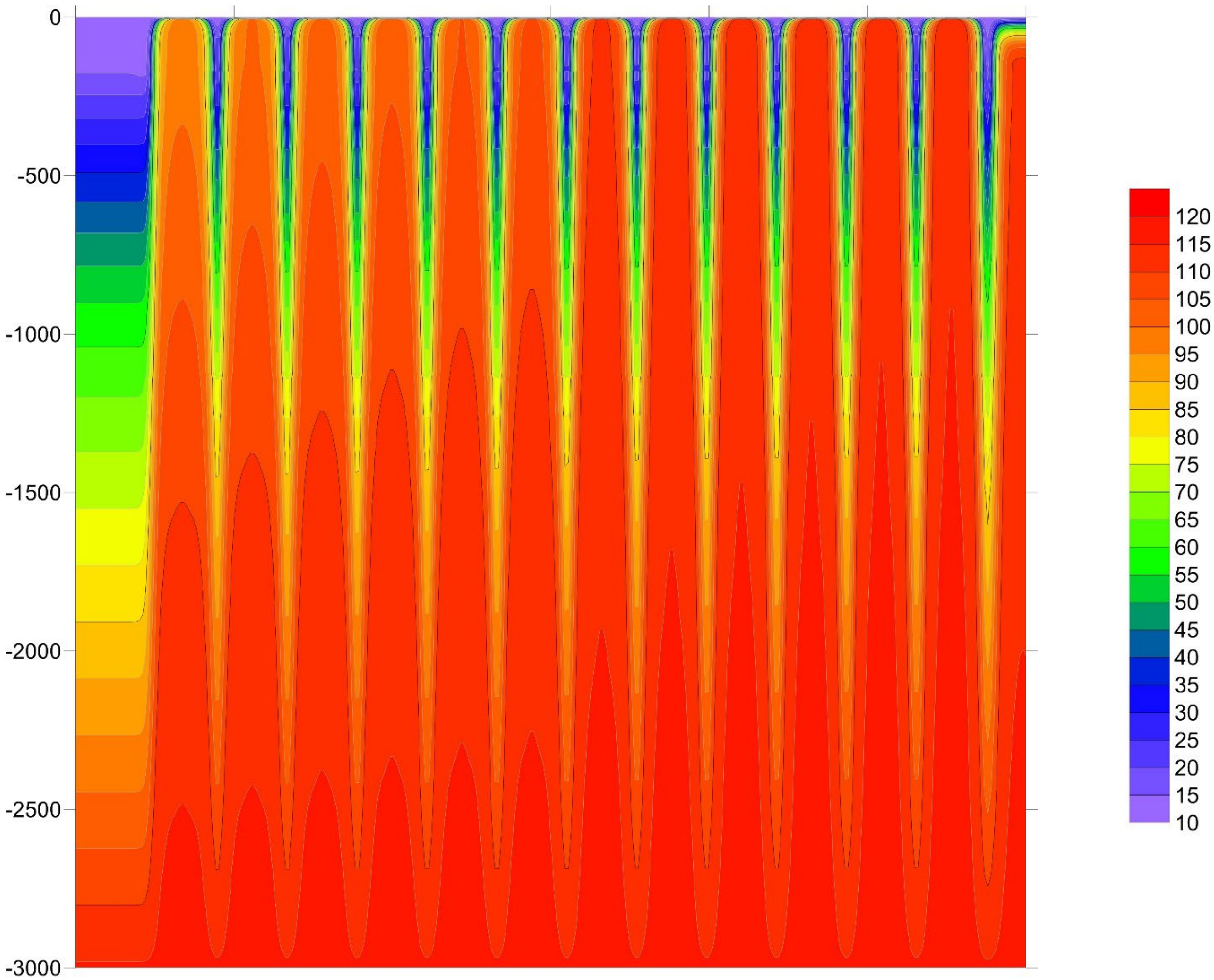
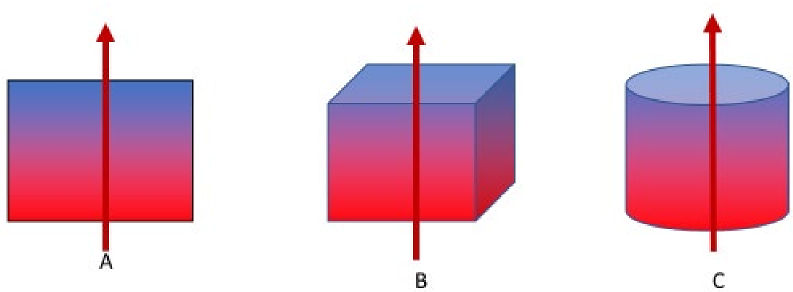


Figure 6. 2-dimensional simulated wellhead temperatures at the flow rates after two years of flow at velocities from 0.05 to 0.17 liters per second.



2.2 Binary geothermal

In 2016, a UND and Continental Resources (CLR) project funded by the US Department of Energy and Calnetix, demonstrated that binary geothermal power could be produced with hot water from a deep (2.6 km) carbonate aquifer in an oil and gas environment. In addition to demonstrating power production with an ORC, information acquired during the project showed that abundant water may be accessible virtually everywhere in the flat-lying and laterally continuous aquifer. This can be seen in Figure 7, which shows locations and production rates for five CLR water supply wells that were drilled for secondary oil recovery projects. The water supply wells were drilled where water was needed, and they all were successful although with different production capacities.

Many of the oil fields in the Williston Basin producing from conventional reservoirs such as the Red River or Madison Formations have associated water flood projects. The wells that supply these projects offer a long term, reliable source of water at relatively high flow rates (tens of liters per second) that offer a potentially attractive geothermal source where fluid temperatures are ~100+°C. Preliminary estimates indicate that a single well providing water to an ORC at that temperature could generate over 400 kW of electricity – adequate to supply power for all the water supply pumping operations plus a significant amount of excess energy to help reduce lifting costs and supply other local power demand. This potential resource could be optimized in future water flood projects if one of the specific design criteria for the water supply wells is to consider targeting deeper, hotter formations where the revenue from the increased geothermal power production would offset any incremental increase in drilling costs.

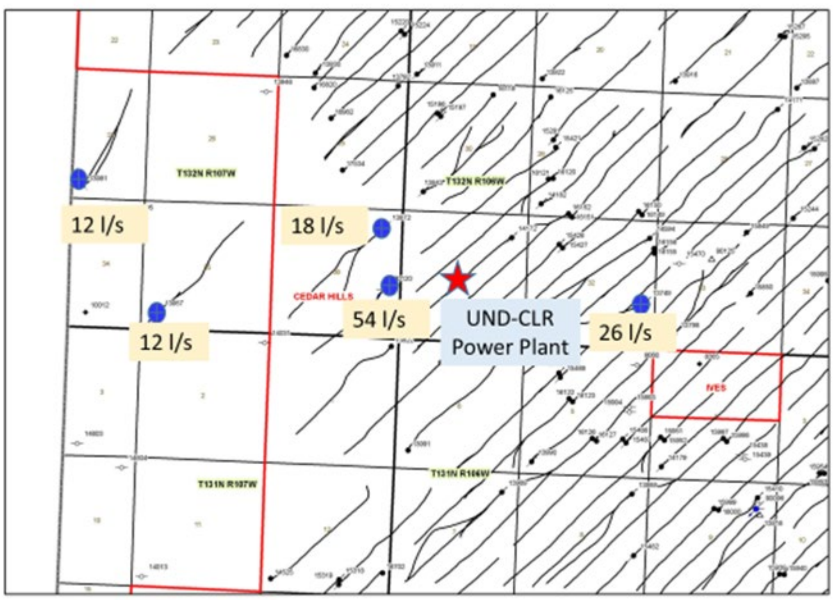


Figure 7. Water supply wells, blue dots, operated by Continental Resources in southwestern North Dakota. The thin black lines are projections of lateral wells in the Red River formation for oil or the Lodgepole formation for water. The red star shows the UND-CLR binary geothermal power plant demonstration site.

2. Conclusions

Coproduction of electrical power using multi-well pads would have a negligible impact on well field electrical power supply. Conversion of marginally economic existing oil wells to water production from the overlying Lodgepole Formation or the hotter, deeper Red River Formation could be a viable option. A high percentage of drilling costs occurs during surface prep. Recompleting an existing well avoids much of that. Installing ORCs on the many water flood projects in the basin would use existing infrastructure with even less cost. Drilling dedicated well fields for geothermal power production could be explored. An effort to develop and install a 5 MW commercial power plant us currently underway in Saskatchewan (DEEP). Finally, the hot waters for low-cost space heating and many other direct use applications could further reduction of energy costs.

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