1. DOE Award Number & Recipient	**DE 0002731** **University of North Dakota**
2. Project Title, Project Director, and Contact Information	RECOVERY ACT: Electric Power Generation from Low to Intermediate Temperature Resources Project Director – Dr. W. Gosnold Will.gosnold@engr.und.edu 701.777.2631
3. Report Date & Period Covered	Submitted 4/28/14 Final Report: June 30, 2015

Project Objectives

1. The primary objective of this project is to demonstrate the technical and economic feasibility of generating electricity from co-produced fluids in oil and gas operations using binary ORC technology

2. A second objective is to demonstrate that the technology can be replicated within a wider range of physical parameters including geothermal fluid temperatures, flow rates, and the price of electricity sales.

3. 3. A third objective is to widely disseminate the results of this study. In addition, the development of a skilled work force will be needed, and therefore facilitating entrepreneurship in development of oil field geothermal resources and training engineers in geothermal energy are included as objectives for this project.

Executive Summary

This project was designed to test the concept on the Eland-Lodgepole Field near Dickinson, North Dakota in the Williston Basin. The field is in secondary-recovery water-flood and consists of 12 producing oil wells, 5 water injection wells and one disposal well. Water production at the site averages approximately 320 gallons per minute (20.2 l s^{-1}) and the temperature is 100 ^{0}C. Engineers at Ormat estimated power production potential with the existing resource to be approximately 350 kWh. Unfortunately, ownership of the field was transferred from Encore, Inc., to Denbury, Inc., within the first week of the project. After two years of discussion and planning, Denbury decided not to pursue this project due to complications with the site location and its proximity to Patterson Lake. Attempts to find other partners operating in the Williston

Basin were unsuccessful. Consequently, we were unable to pursue the primary objective of the project. However, during negations with Denbury and subsequent time spent contacting other potential partners, we focused on objectives 2 and 3 and developed a clear understanding of the potential for co-produced production in the Williston Basin and the best practices for developing similar projects.

At least nine water bearing formations with temperatures greater than 90 ºC extend over areas of several 10s of km^2. The total energy contained in the rock volume of those geothermal aquifers is 283.6 EJ (1 EJ = 10^{18} J). The total energy contained in the water volume, determined from porosities which range from 2 percent to 8 percent, is 6.8 EJ. The aquifers grouped by 10 ºC temperature bins (Table 1) include one or more formations due to the bowl-shape structure of the basin.

T ºC	km^3 Rock	km^3 Water	EJ Rock	EJ Water
90° -100°	192,467	10,486	3.2E+01	1.7E+00
100° -110°	255,799	12,430	3.2E+01	1.7E+00
110° - 120°	226,723	10,937	5.2E+01	9.9E-01
120° - 130°	204,628	10,166	5.7E+01	1.0E+00
130° - 140°	122,569	5,333	6.0E+01	1.1E+00
140° - 150°	60,806	1,766	4.1E+01	8.4E-01
T ≥ 150°	45,248	1,257	1.9E+01	5.3E-01

Table 1. Summary of energy available in geothermal aquifers in the Williston Basin

Analysis of overall fluid production from active wells, units, fields and formations in North Dakota showed that few sites co-produce sufficient fluid for significant power production with ORC technology. Average co-produced water for 10,480 wells is 3.2 gallons per minute (gpm). Even excluding the tight formations, Bakken and Three Forks, average co-produced water for the remaining 3,337 is only 5 gpm. The output of the highest producing well is 184 gpm and the average of the top 100 wells is 52 gpm. Due to the depth of the oil producing formations in the Williston Basin, typically 3 km or greater, pumps are operated slowly to prevent watering out thus total fluid production is purposefully maintained at low volumes.

There remain potential possibilities for development of geothermal fluids in the Williston Basin. Unitized fields in which water production from several tens of wells is collected at a single site are good possibilities for development. Water production in the unitized fields is greater than 1000 gpm is several areas. A similar possibility occurs where infill-drilling between Bakken and Three Forks horizontal wells has created areas where large volumes of geothermal fluids are available on multi-well pads and in unitized fields. Although the Bakken produces small amounts of water, the water/oil ration is typically less than 1, the oil and water mix produced at the well head can be sent through the heat exchanger on an ORC. It is estimated that several tens of MWh of power could be generated by a distributed system of ORC engines in the areas of high-density drilling in the Bakken Formation. Finally, horizontal drilling in water bearing formations is the other possibility. Several secondary recovery water-flood projects in the basin are producing water above 100 ^{o}C at rates of 300 gpm to 850 gpm. Those systems also could produce several tens of MWh of power with ORC technology.

Objective 3 of the project was highly successful. The program has produced 5 PhDs, 7 MS, and 3 BS students with theses in geothermal energy. The team has involved 7 faculty in 4 different engineering and science disciplines, ChE, EE, GE, and Geol. The team has produced 26 peer-reviewed papers and 62 presentations at professional meetings. Faculty involved in the program developed five graduate level courses covering different elements in heat flow and geothermal energy that are now offered in the Harold Hamm School of Geology and Geological Engineering.

Lessons learned – Keys to developing a successful project

1. Determine target formations.
    a. Data from oil and gas operators, state oil and gas regulatory agencies, and state geological surveys help to identify producing formations and their properties.
2. Determine the quantity of energy available in the target formations.
    a. A complete thermal analysis of the basin or region yields the most useful information.
    b. Critical data include: BHT, heat flow, stratigraphy, lithology, lithological properties, and thermal conductivity, subsurface structure.
3. Determine fluid production potential.
    a. State oil and gas regulatory agencies, and state geological surveys have data on oil, gas and water production. State Water Commission/Agencies have data on water quality, aquifers, and regulations.
    b. Consider single horizontal wells, multiple conventional wells, and unitized fields.
4. Calculate energy production capacity of each formation based on different well combination and power plant scenarios. This is a broad overview rather than a site specific analysis.
5. Research and understand the local electrical power industry. Obtain the PPA before committing to the project.
6. Work with the high-level personnel in the oil company partner. Obtain an MOU that addresses all issues in the project including what to expect if the company goes out of business, is bought out, changes management, etc.
7. Be prepared for project delays.

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Introduction

Capturing the heat in the large volumes of fluids produced from oil and gas operations has been a promising concept for geothermal development for the past decade (Erdlac and Swift, 2004; McKenna, Blackwell and Moyes, 2005; Blackwell, 2006; Johnson and Schochet, 2007, Augustine and Falkenstern, 2012.) It has been proposed that using co-produced fluids at temperatures sufficient for power generation in binary power systems could produce up to 0.451 EJ or 125 TWh of power (Idaho National Engineering Laboratory, 2006), and there have been significant efforts to promote this concept. Southern Methodist University (SMU) has hosted six conferences on Geothermal Energy in Oil and Gas Fields between 2006 and 2015, the National Renewable Energy Laboratory (NREL) has conducted analyses of the electrical power that could be generated from co-produced water (Augustine and Falkenstern, 2012), and the Department of Energy Geothermal Technologies Office (GTO) has funded demonstration projects (Gosnold, Mann, and Salehfar, 2010, 2013, 2015.) In spite of the interest shown at the well-attended SMU conferences and by the efforts of NREL and GTO, the only active geothermal oil field project at present is the DOE low-temperature demonstration project in North Dakota (Gosnold, Mann, and Salehfar, 2015.)

This report summarizes the efforts of the UND team to develop a co-produced geothermal demonstration project in the oil fields in the Williston Basin. Each of the three objectives is addressed in sequence.

Objective 1 – Test the Technical and Economic Feasibility of Electrical Power Generation from Co-Produced Geothermal Waters

The site selected for this co-produced project was the Eland-Lodgepole Field near Dickinson, ND. The Lodgepole Formation is the basal member of the carbonate and evaporate dominated Madison Formation (Mississippian) and is notable for the occurrence of reservoir forming "Waulsortian Reefs." The Eland Lodgepole Field consists of 12 oil and gas wells, 5 water injection wells and one disposal well. Water temperature at the collection site is slightly greater than 100 ^{0}C and flow averages approximately 320 gallons per minute. Data from the North Dakota Industrial Commission Oil & Gas web site (https://www.dmr.nd.gov/oilgas/) show that the field was in primary recovery mode from December 1994 through February 1997 and has been in secondary recovery mode by water flood since March 1997, Figure 1. Water production has averaged 342,935 bbl per month (320 gallons per minute) since 2006 and total fluid (oil + water) production has averaged 367 gpm since 2006. The low volume of fluid production from the 12 combined wells is due to the slow pumping rate which helps to reduce the Water to Oil Ratio (WOR). The WOR has increased steadily from an initial value significantly less than 1 to 17:1 at present. Fluid production in bbl per month for the field show a typical decline in oil production and increase in water production over time. Water from the 12 producing wells in the unitized field is collected at a central location, thus the field has good potential for binary geothermal power development.

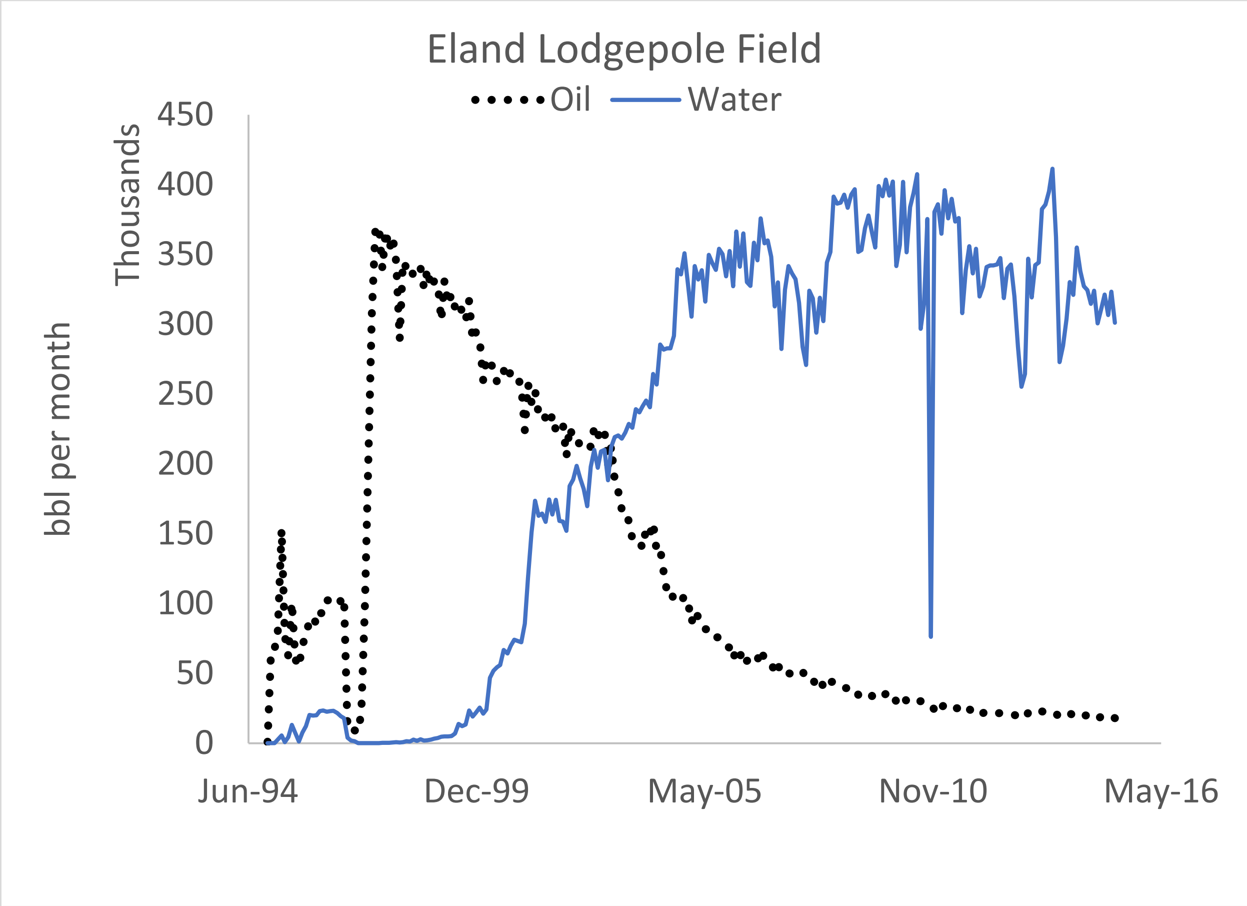


Figure 1. Oil and water production from the Eland-Lodgepole Field.

Unfortunately, after two years of discussion and planning, the oil field operator, Denbury, decided not to pursue this project due to complications with the site location and its proximity to Patterson Lake, the water supply for Dickinson, ND. Attempts to find other partners operating in the Williston Basin by contacting major and minor operators were unsuccessful. The lack of interest in geothermal development by the petroleum industry in the Williston Basin is likely due to the intense horizontal drilling boom in the Bakken and Three Forks formations. The two oil and gas producing formations in the basin that are capable of producing significant amounts of water, the Red River and the Madison, were quickly taking a back seat in operations. And non-oil revenue producing activity was not of any interest. Consequently, the primary objective of the project, installation and operation of an ORC using co-produced fluids, was unattainable. However, during negations with Denbury and subsequent time spent contacting other potential partners, the focus on objectives 2 and 3 led to a good understanding of the potential for co-produced production in the Williston Basin.

Objective 2 - Demonstrate that the technology can be replicated within a wider range of physical parameters including geothermal fluid temperatures, flow rates, and the price of electricity sales.

The essential data for assessing the feasibility of producing geothermal power are temperature and depth of the resource and availability of fluid to transport the energy to the surface. Additional considerations include detailed stratigraphy, fluid composition, surface climate, geographic location, and accessibility of the power grid, as well as hydrologic, mechanical, geochemical, and thermal properties of the basin. These matters in the following three sections: Temperature, Fluid Availability, and Economics.

The accumulated data include bottom-hole temperatures for 10,968 wells, formation temperatures and depths for 5,031 abandoned or shut in wells, formation temperatures and depths for 5,922 active wells, water and oil production volumes and rates for 6,115 active wells, 33 conventional terrestrial heat flow measurements, 303 heat flow estimates from bottom-hole temperatures, and 368 thermal conductivity measurements on core samples. The data are included in the appendices.

Subsurface Temperatures

The goal of the subsurface temperature analysis was to identify areas and specific geologic units that contain fluids hot enough for electric power generation with binary ORC or other energy conversion systems. Subsurface temperatures in the Williston Basin were evaluated by two methods. The first analysis was based on the bottom-hole temperature (BHT) data from well logs of 10,968 oil and gas wells available on the North Dakota Industrial Commission website; https://www.dmr.nd.gov/oilgas/. The second analysis was based on combining heat flow, temperature vs. depth measurements, thermal conductivity, and stratigraphy to predict temperatures at depth.

Bottom Hole Temperatures

A composite temperature vs. depth pattern from BHTs for the North Dakota portion of the Williston Basin appears to be linear (Figure 2). Temperature vs. depth profiles recorded at equilibrium conditions in three deep wells and a linear fit to the BHT data (Figure 3) show that the BHT data significantly understate actual formation temperatures and that thermal gradient is not linear. Stratigraphic and thermal conductivity data show that the temperature gradient is controlled by a systematic change in thermal conductivity of the formations in the basin. The primarily fine-grained clastic rocks in the upper portions of the basin have low thermal conductivities and high temperature gradients. The primarily carbonate and dolomitic rocks in the lower portions of the basin have high thermal conductivities and low temperature gradients. The composite BHT data reflect the commonly observed effect of mud circulation; i.e., heating above formation temperature in the shallow regions and cooling below formation temperature in the deeper regions. The temperature difference between the BHT and both the measured and calculated temperature profiles is approximately 12 °C at all depths below 2,000 m. This difference is significant because it occurs where formation temperatures are above 90 °C, the threshold temperature for binary power generation. Analysis of the applicability of both the Harrison and SMU corrections to the BHT data showed that the Harrison correction gives better agreement for the Williston Basin (Crowell and Gosnold, 2011).

The equilibrium temperature profiles (Figure 3) show the effect of differences in thermal conductivities (Table 2) on temperature gradients between the fine-grained clastic rocks of Cenozoic and Mesozoic age and the carbonates of Paleozoic age. A linear fit to the composite data yields a temperature gradient of 27 K km^{-1} and a surface intercept of 13 °C. A linear fit to the carbonate section in the lower part of the basin yields a temperature gradient of 11 K km^{-1} and a surface intercept of 28 °C. The temperature gradients measured at equilibrium conditions in three wells average 45 K km^{-1} in the clastic section and 27 K km^{-1}carbonate section. The surface intercept for the equilibrium temperature profiles is 8 °C which is close to the mean annual air temperature in western North Dakota. The surface intercept for geothermal gradients is an important parameter in that any difference from the mean annual air temperature indicates a possible disturbance to the temperature vs. depth data or significant changes in thermal conductivity in the vertical sections.

Formation	System	Rock Type	Cond. W/m/K	N	RBT 1981	Difference
Pierre	Cretaceous	Sh	0.88 ± 0.26	23	1.1	-19.1%
Madison	Mississippian	Ls	2.49 ± 0.48	36	3.5	-30.6%
Birdbear	Devonian	Ls	3.13 ± 0.73	29	3.5	-30.6%
Duperow	Devonian	Ls	3.19 ± 0.51	44	3.5	-11.4%
Souris River	Devonian	Ls	2.92 ± 0.48	23	3.5	-18.0%
Dawson Bay	Devonian	Ls / Do	2.75 ± 0.60	18	3.5	-22.9%
Winnipegosis	Devonian	Ls / Do	2.99 ± 0.70	10	3.5	-18.6%
Ashern	Devonian	Ls / Do	3.10 ± 0.24	6	3.5	-12.3%
Interlake	Silurian	Do / Ls	3.77 ± 0 .64	29	3.5	20.3%
Stonewall	Silurian	Do / Ls	3.89 ± 0 .01	2	3.5	12.3%
Stony Mt.	Silurian	Do / Ls	3.79 ± 0.67	13	3.5	18.3%
Red River	Ordovician	Ls / Do	3.28± 0.94	47	3.5	-3.4%
Black Island	Ordovician	Do / SS	4.71 ± 0.52	5	3.5	36.0%
Winnipeg	Ordovician	Do / SS	4.07 ± 0.39	14	3.5	12.9%
Deadwood	Cambrian	Do /SS	3.46 ± 1.02	69	2.4	54.6%

Table 2. Thermal conductivities measured on core samples from the Williston Basin using a divided bar apparatus. The RBT 1981 reference is Roy, Beck, and Touloukian (1981).

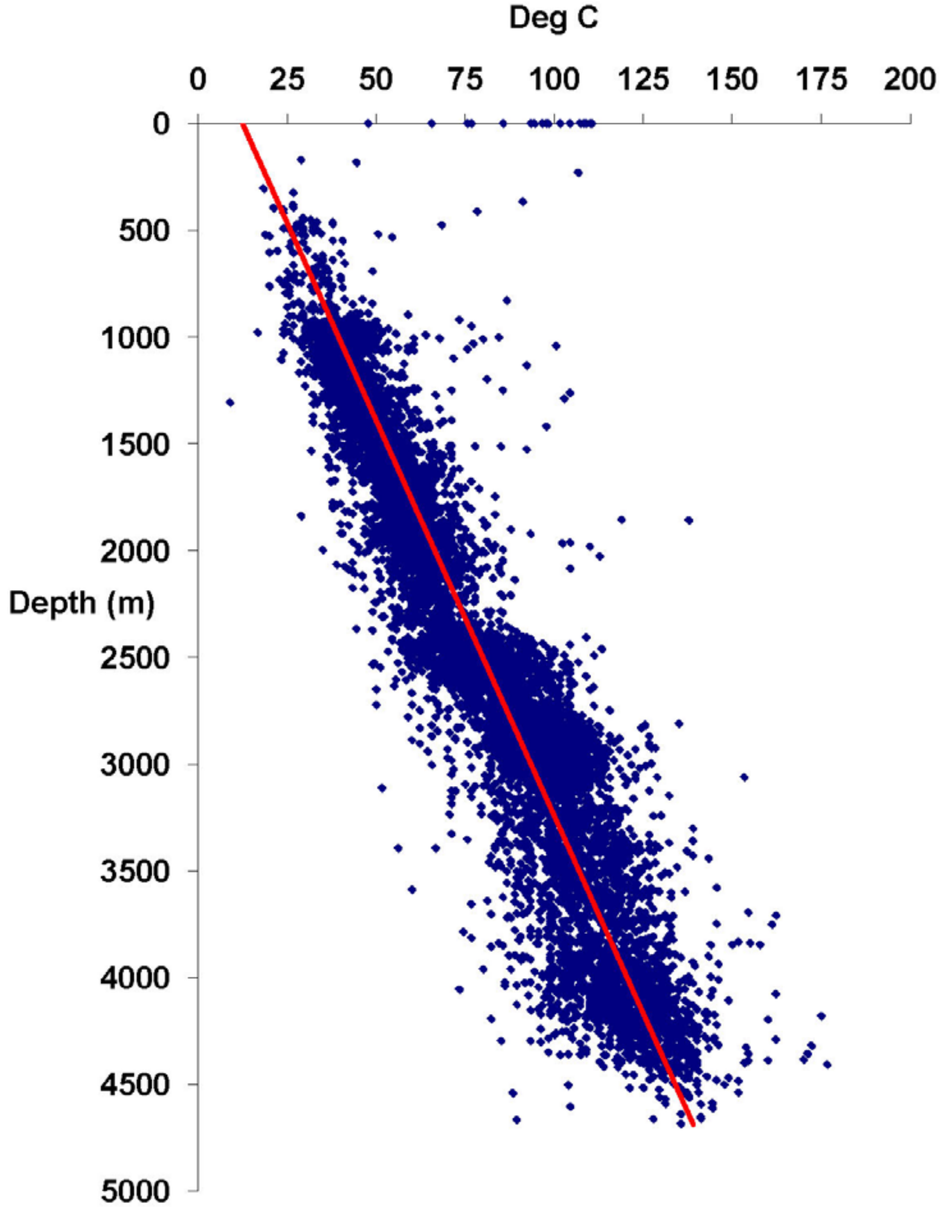


Figure 2. Composite BHT data vs. depth for the North Dakota portion of the Williston Basin. The linear fit to the data gives a temperature gradient of 27 K km^{-1} with a surface intercept of 13 °C.

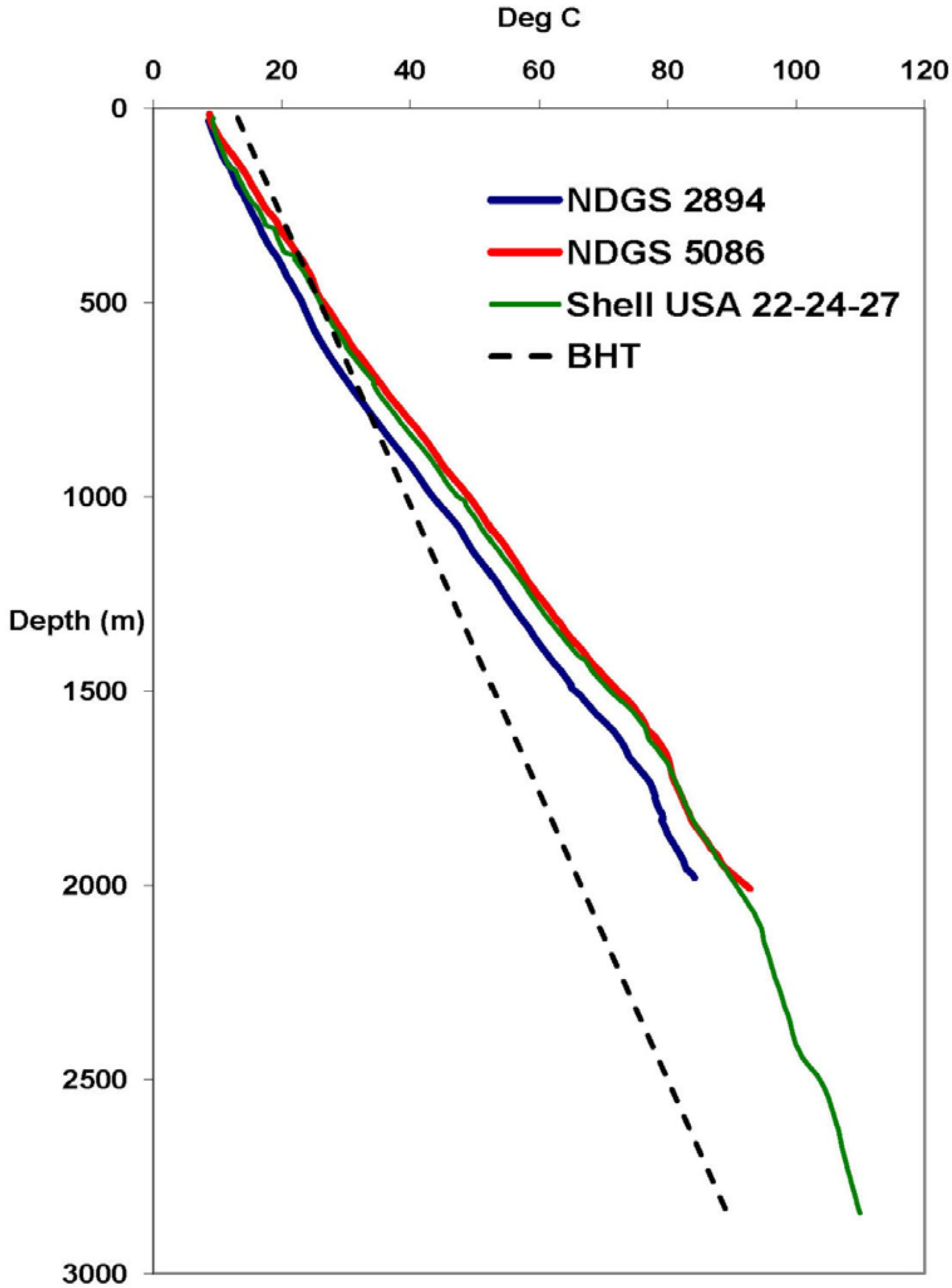


Figure 3. Three temperature vs. depth profiles measured at thermal equilibrium conditions compared to a linear fit to the BHT data in Figure 2.

The BHT data are being combined with 5,922 well logs containing depth to formation tops to produce temperature contour and depth contour maps for specific geothermal aquifers. Locations of the BHT data and the formation data are shown in Figures 4 and 5.

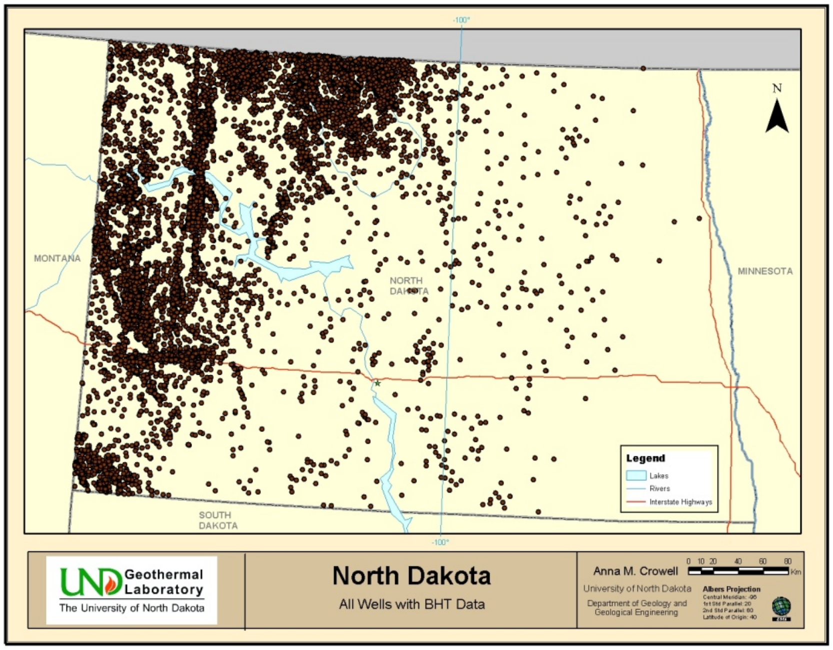


Figure 4. Map of wells in North Dakota with bottom-hole temperatures.

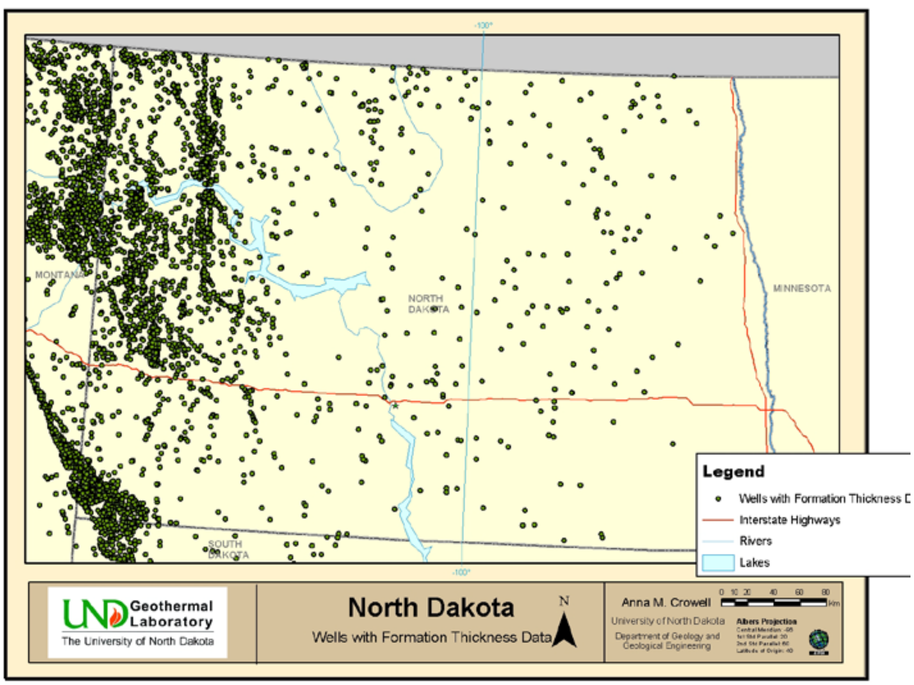


Figure 5. Map of wells in North Dakota with formation depths.

We combined the BHT and depth to formation data to generate maps of temperatures of formations representing specific geologic systems (Figures 6 – 10). Each map shows wells with recorded BHTs at 10 °C intervals from 90 °C to 150 °C. There is scatter in the data, see Figure 2, but the overall patterns are consistent with the higher temperatures mapping into the deeper parts of the basin. The 12 °C temperature difference between BHTs and equilibrium temperatures for all depths below 2,000m was not applied to any of these maps although all points represented are at depths greater than 2,000 m.

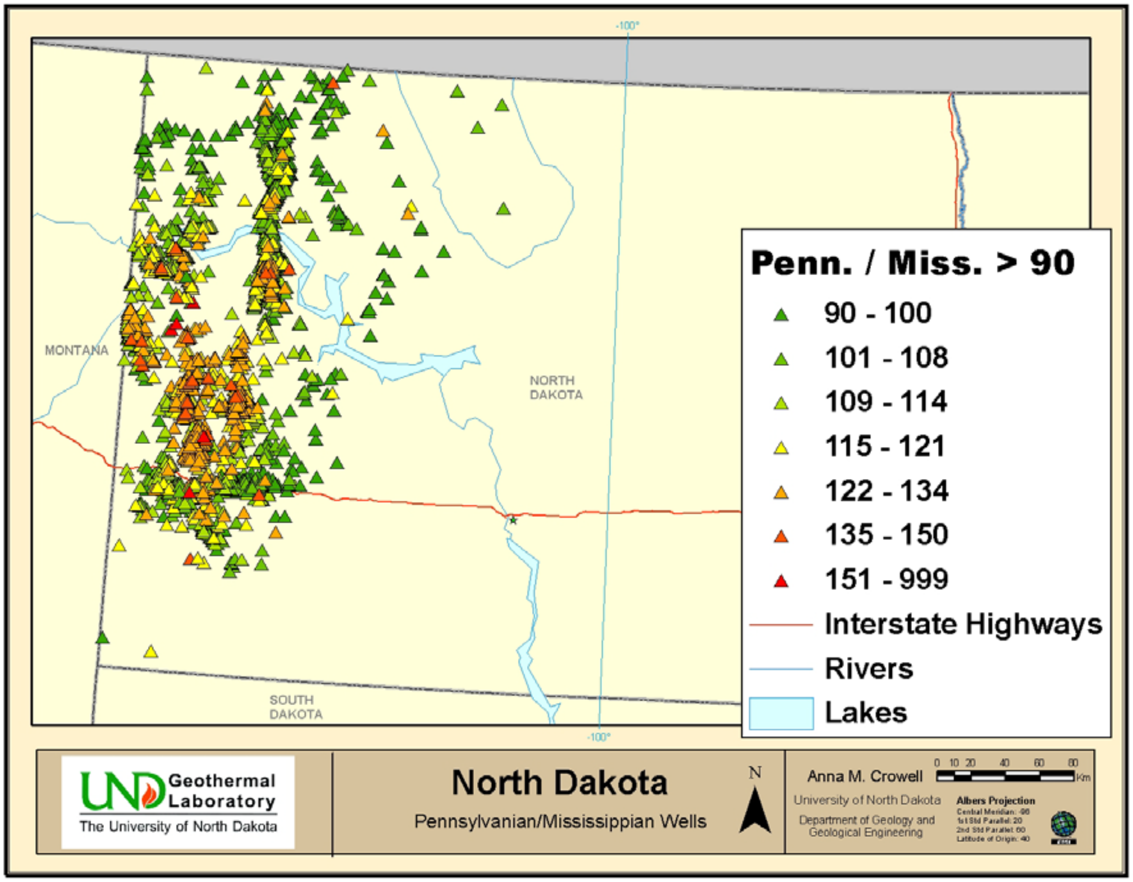


Figure 6. Map of bottom-hole temperatures for Pennsylvanian and Mississippian formations in North Dakota. The Madison Formation includes the Charles, Mission Canyon, and Lodgepole.

System	Formation	Rock Type	Max Thickness
Pennsylvanian	Amsden	Do, SS	135
	Tyler	Sh, Ls	80
	Otter	Sh	60
Mississippian	Kibbey	Ss, Ls	75
	Madison	Ls	600

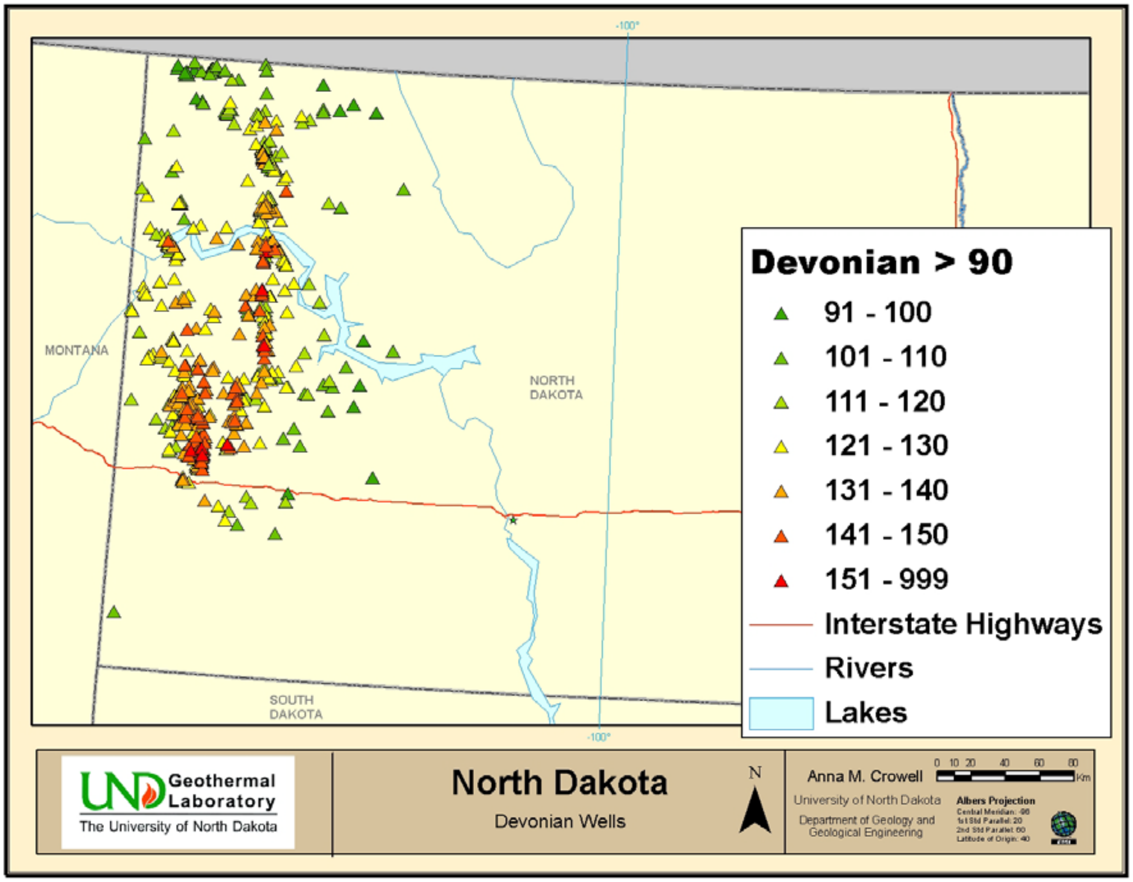


Figure 7. Map of bottom-hole temperatures for Devonian formations in North Dakota. The Devonian formations are the Bakken, Three Forks, Birdbear, Duperow, Souris River, Dawson Bay, Prairie, and Winnepegosis. The Devonian section has a maximum thickness of 770 meters and all formations below the Three Forks are potential geothermal reservoirs.

System	Formation	Rock Type	Max Thickness
Devonian	Bakken	Sh	35
	Three Forks	SltS	75
	Birdbear	Ls, Do	40
	Duperow	Ls, Do	140
	Souris River	Do, Ls	105
	Dawson Bay	Ls, Do	55
	Prairie	Evap	200
	Winnepegosis	Do, Ls	120

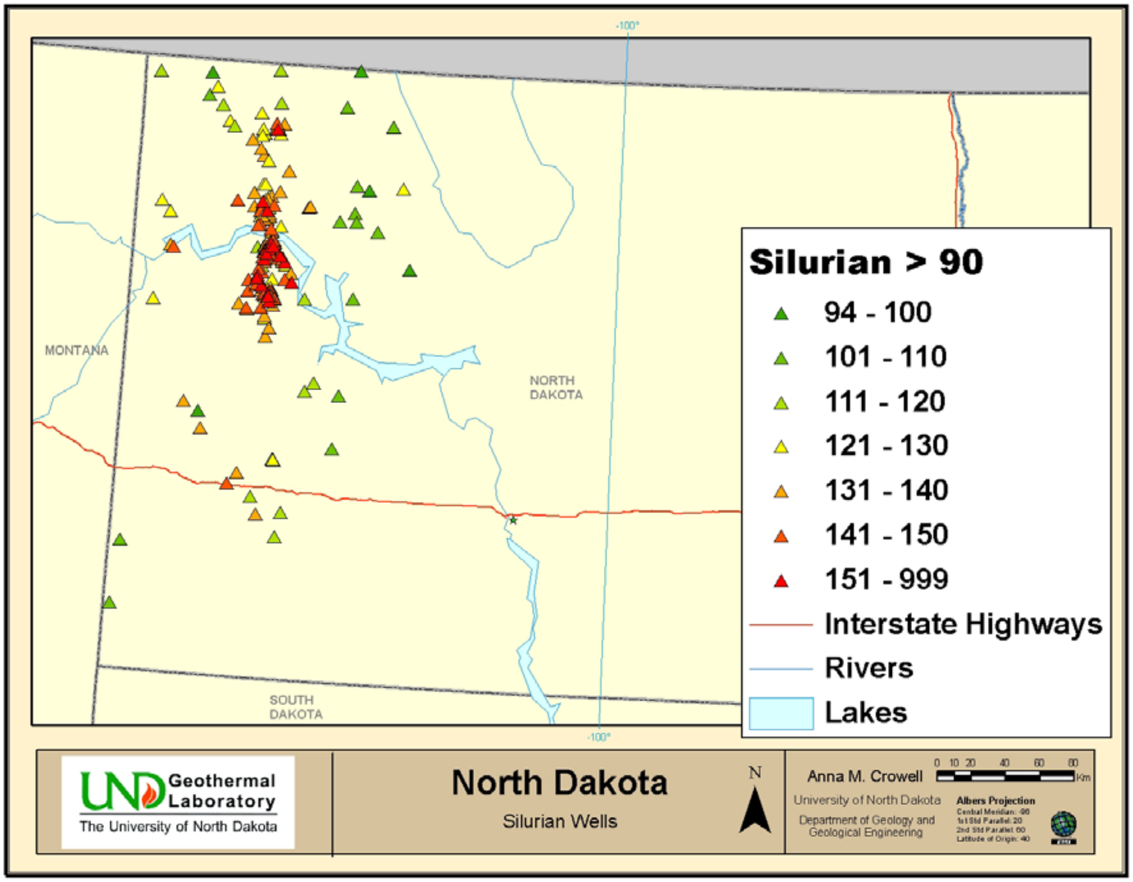


Figure 8. Map of bottom-hole temperatures for Silurian formations in North Dakota. The Silurian formations are the Interlake and Stonewall. They have a maximum thickness of 370 meters and are composed of dolomite and limestone.

System	Formation	Rock Type	Max Thickness
Silurian	Interlake	Do, Ls	335
	Stonewall	Do, Ls	35

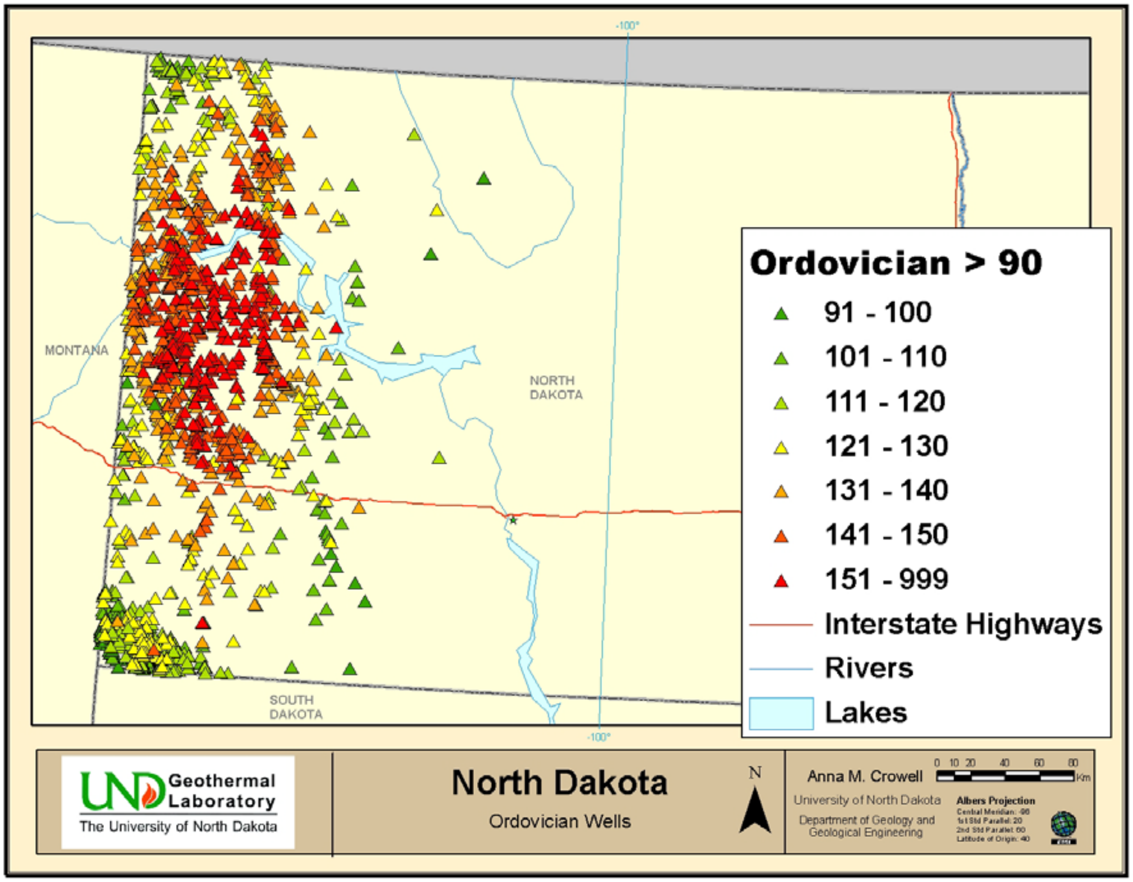


Figure 9. Map of bottom-hole temperatures for Ordovician formations in North Dakota. The Ordovician formations are the Stony Mountain, Red River, and Winnipeg Group. They have a maximum thickness of 400 m and are primarily composed of dolomite, and limestone, with some siltstone, sandstone and shale in the lowest member.

System	Formation	Rock Type	Max Thickness
Ordovician	Stony Mountain	Do, Ls	60
	Red River	Ls, Do	215
	Winnepeg	StS, SS, Sh	125

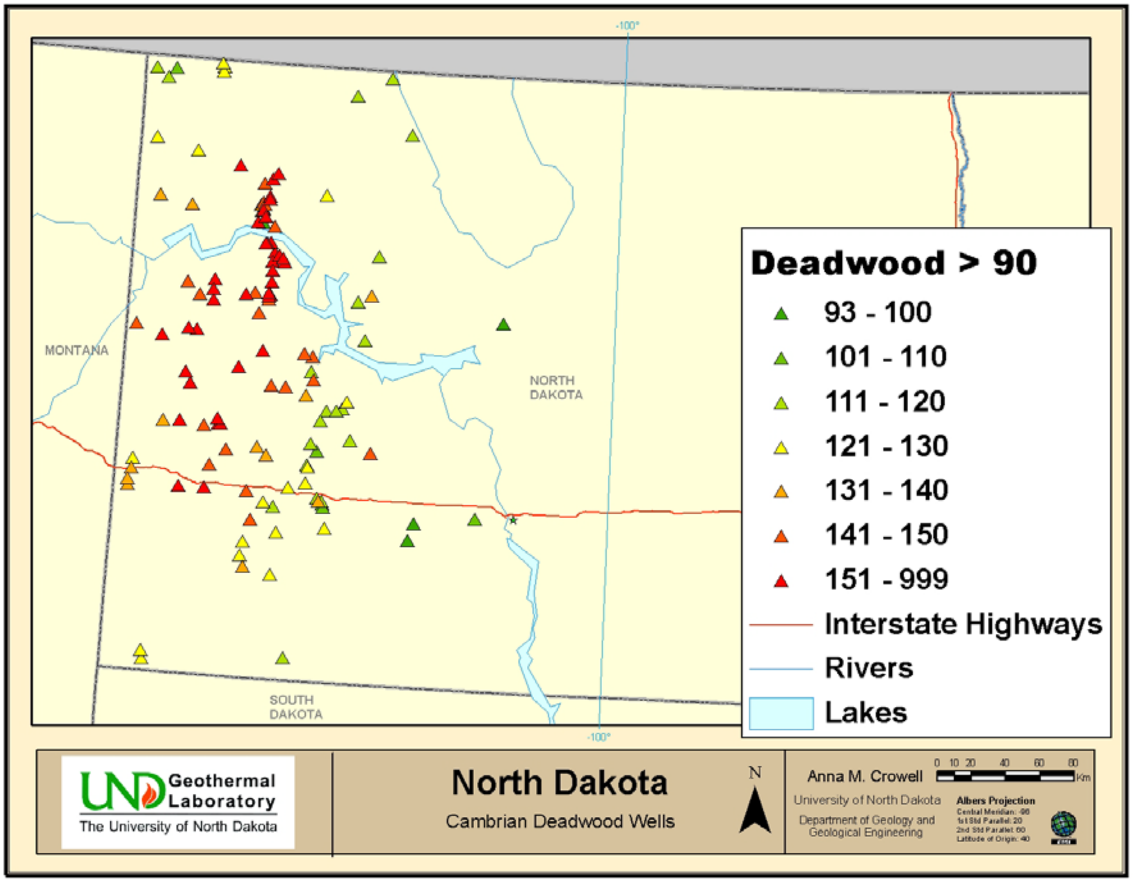


Figure 10. Map of bottom-hole temperatures for the Cambrian, Deadwood Formation, in North Dakota. The Deadwood has a maximum thickness of 300 meters and is composed of limestone, sandstone, and shale.

System	Formation	Rock Type	Max Thickness
Cambrian	Deadwood	Ls, SS,Sh	300

Thermal Stratigraphy

Heat flow, thermal conductivity, and stratigraphic data can be combined to calculate temperatures at depth. Integration of Fourier's law of heat conduction:

$$q = \frac{dT}{dz}\Lambda \qquad \text{Eq. 1}$$

where q is heat flow in mW m^{-2}, $\frac{dT}{dz}$ is temperature gradient in mK m^{-1}, and Λ is thermal conductivity in W m^{-1} K^{-1} yields

$$T(z) = T_0 + \sum_i^n \frac{z_i q}{\Lambda_i} \qquad \text{Eq. 2}$$

The Williston Basin has a bimodal composition with a 1 to 2 km thick layer of Cenozoic and Mesozoic strata consisting principally of shales overlying 2 to 3 km of Paleozoic limestones and dolomites. There are 54 distinct formations within the Williston Basin and thermal conductivity values have been measured on only fourteen of the Paleozoic formations and one of the Mesozoic formations (Gosnold et al., 2010). Thermal conductivity was found to vary significantly within formations (Figure 11), thus selecting a single value for a specific formation is questionable. However the range of thermal conductivity variation is useful in fitting calculated temperatures to observed equilibrium profiles.

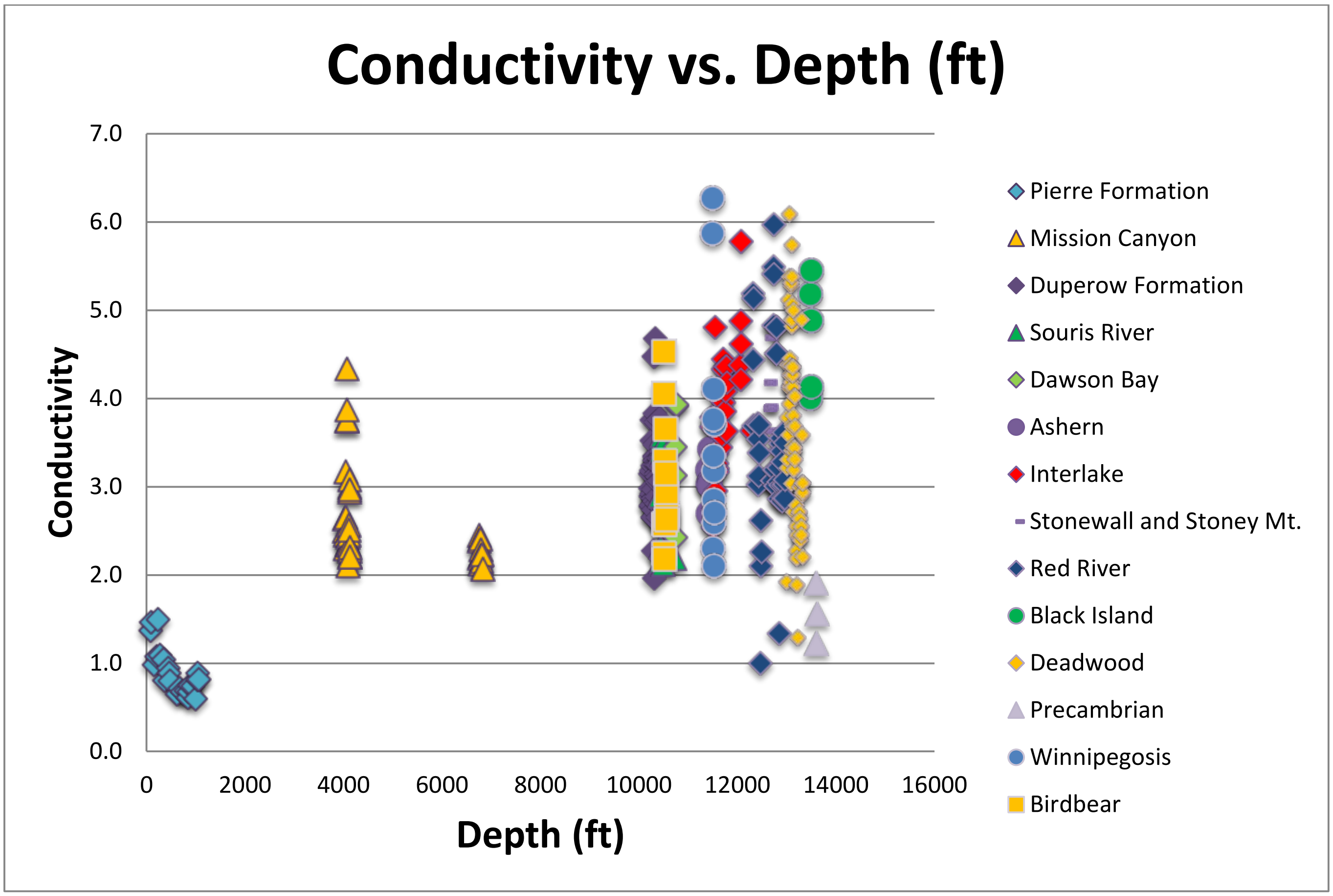
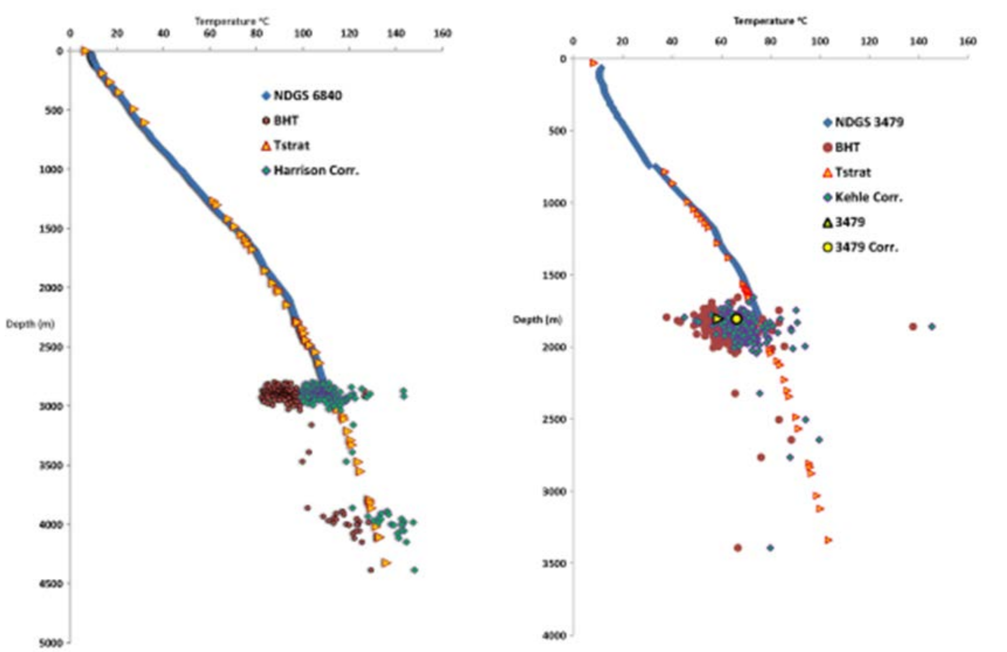


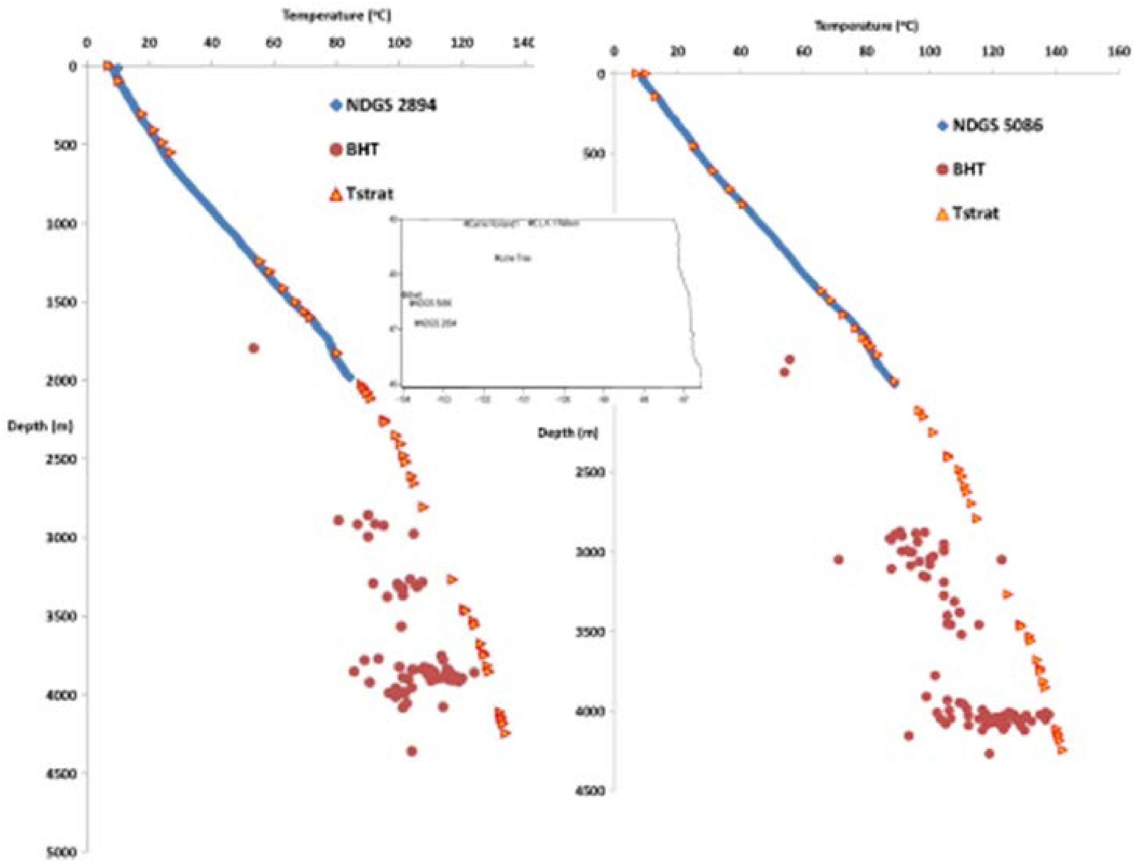
Figure 11. Thermal conductivity measured with a divided bar on core samples provided by the North Dakota Geological Survey. Depth units are in feet

Five temperature vs. depth profiles that were measured in boreholes at thermal equilibrium. Four of the profiles are entirely in the shale section, but one profile, NDGS 6840, reached a depth of 2845 m and extends through the Madison Group carbonates. The temperature gradient in the Madison between 2640 and 2845 m averages 16.9 ± 2.4 K km^{-1} Core from the well was not available for thermal conductivity measurements, but it was estimated as follows. The average temperature gradient in the shale section of NDGS 6840 is 46.9 ± 11.6 K km^{-1} and the shale section has a thermal conductivity of 1.1 W m^{-1} K^{-1}. This yields a heat flow of 51.6 mW m^{-2} for that site. Assuming constant heat flow in the borehole, the thermal conductivity of the Madison in NDGS is calculated to be 3.05 W m^{-1} K^{-1}. Using heat flow of 51 mW m^{-2} and adjusting thermal conductivities of each formation penetrated by the borehole, TSTRAT can fit a calculated temperature profile to the observed profile. The method was used to calculate temperatures on all formation tops from the bottom of the observed temperature data to the Precambrian basement.

The analysis was applied to each of the four wells with T-z profiles and the results were combined with the bottom hole temperature data from all boreholes within a 10 km of the well. A small but persistent misfit between the calculated temperature vs. depth profile and the observed profiles occurs in the upper km of each of the five boreholes. The misfit is inferred to be due to a transient disturbance of the temperature gradient in the upper 1 km from the effects of post-glacial warming (Gosnold et al., 2011; Majorowicz et al., 2012). These results improved our understanding of heat flow and subsurface temperatures in the basin. In fact, the results indicate a higher heat flow throughout the basin that was determined from shallow temperature vs. depth measurements.



Figures 12 & 13. Application of TSTRAT for wells NDGS 6840 and NDGS 3479 which have equilibrium temperature vs. depth logs. The BHT data are from wells within 10 km of the two wells. See Figures 14 & 15 for location within the basin. The BHT data were corrected using the Kehle correction (Kehle et al., 1970) which tends to under correct at shallow depths and over correct at greater depths. The TSTRAT calculation, Eq. 2, uses heat flow, thermal conductivity, and stratigraphic thickness to match predicted temperature with an observed equilibrium temperature profile.



Figures 14 & 15. Application of TSTRAT for wells NDGS 2894 and NDGS 5086 which have equilibrium temperature vs. depth logs. The inset map shows locations for these two wells and NDGS 6840 (Shell) and NDGS 3479 (ELK1 Nelson).

Resource Estimates

The common method for assessing geothermal resources is to determine reservoir volume and heat content and estimate the producible fraction of geothermal fluids (Nathenson, 1975; White and Williams, 1975; Muffler and Cataldi, 1978; Muffler, 1979; Lovekin, 2004; Williams, Reed, and Mariner, 2008). The accessible resource base is derived from the heat content and is calculated by

$$q_R = \rho c a d (T - T_{ref}) \qquad \text{Eq. 3}$$

Where; $\mathbf{q_R}$ is the resource base (J), $\boldsymbol{\rho c}$ is volumetric specific heat of rock plus water (J m^{-3} K^{-1}), **a** is formation area (km^2), and **d** is formation thickness (km), (Sorey, Nathenson and Smith, 1983). This method was previously applied to the Williston Basin for assessing low temperature geothermal resources in three successive studies (Sorey et al., 1983; Gosnold; 1984; Gosnold; 1991).

The first assessment (Sorey et al., 1983) addressed the energy stored in two well-known aquifers, the Madison Group (Mississippian) and the Dakota Group (Cretaceous). Average temperatures were estimated for each aquifer, 63 °C for the Madison and 62 °C for the Dakota, and a reference temperature, T_{ref}, of 15 °C was assigned for the calculation. Volumetric heat capacity was calculated as 2.6 x 10^{-6} J m^{-3} K^{-1} based on weighted averages for rock types and porosities typical of sedimentary basins. This first assessment yielded mean accessible resource base (MARB) estimates of 5,800 ± 470 x 10^{18} J for the Madison Formation and 628 ± 70 x 10^{18} J for the Dakota Formation. Subsequently, Gosnold (1984) included two additional aquifers, Duperow and Red River, and estimate the MARB as 13,500 x 10^{18} J. In a more extensive follow-up study involving new heat flow data, Gosnold (1991) included all oil producing formations and estimated the MARB as 21,250 x 10^{18} J.

These previous resource estimates used a reference temperature of 15 °C which led to large ΔTs and large resource estimates. Similar calculations for electric power generation with binary energy conversion systems must be based on the cooling efficiency of the heat exchanger and will have a higher reference temperature. Discussions with ORC suppliers indicates that a reference temperature of 50 °C would be appropriate for existing technology with air cooling in North Dakota's climate. Most of North Dakota's oil fields lie in arid regions with no streams or lakes that could supply cooling water. The regions bordering the Missouri River, Souris River, and Yellowstone Rivers could use water for cooling although there are few wells within 10 km of those streams.

Tables 3-9 show the calculated mean accessible base resource at different temperature ranges to account for different ΔTs using a reference temperature of 50 °C. We combined the formations in each geologic system to simplify the tables. Thicknesses of the systems were taken from the well log data represented in Figure 4 and temperatures were taken from the BHTs represented in Figure 3. Porosities were taken from samplings of well logs and system areas were calculated from the formation data represented in Figure 4. We calculated the total mean accessible resource base for binary electric power generation with existing technology as 259 EJ (2.59 x 10^{20} J).

90° -100°		Avg Thick	Area	Rock Volume	H_2O Volume	Energy R.	Energy W.
Fm or Sys	Porosity	km	km^2	km^3	km^3	Joules	Joules
Mississippian	0.15	2.61	54,400.34	95,313.53	14,297.03	1.59E+19	2.39E+18
Devonian	0.18	1.50	23,071.55	34,538.10	6,216.86	5.78E+18	1.04E+18
Silurian	0.04	0.80	20,728.59	16,679.01	729.57	2.79E+18	1.22E+17
Ordovician	0.08	1.13	34,281.26	38,864.32	3,225.74	6.50E+18	5.40E+17

Cambrian	0.07	0.51	13,741.71	7,072.38	495.07	1.18E+18	8.28E+16

Table 3. Mean accessible resource for reservoirs temperatures of 100 °C to 110 °C..

100° -110°		Avg Thick	Area	Rock Volume	H_2O Volume	Energy R.	Energy W.
Fm or Sys	Porosity	km	km^2	km^3	km^3	Joules	Joules
Mississippian	0.15	2.61	49,217.18	95,149.61	14,272.44	1.99E+19	2.98E+18
Devonian	0.18	1.50	43,802.14	65,571.81	11,802.92	1.37E+19	2.47E+18
Silurian	0.04	0.80	33,701.13	27,117.21	1,186.16	5.67E+18	2.48E+17
Ordovician	0.08	1.13	49,722.84	56,370.29	4,678.73	1.18E+19	9.78E+17
Deadwood	0.08	0.51	16,004.46	8,236.94	658.95	1.38E+17	1.38E+17

Table 4. Mean accessible resource for reservoirs temperatures of 100 °C to 110 °C.

110° - 120°		Avg Thick	Area	Rock Volume	H_2O Volume	Energy R.	Energy W.
Fm or Sys	Porosity	km	km^2	km^3	km^3	Joules	Joules
Mississippian	0.15	2.61	42,280.47	84,061.10	12,609.16	2.11E+19	3.16E+18
Devonian	0.18	1.50	26,988.29	40,401.48	7,272.27	1.01E+19	1.82E+18
Silurian	0.04	0.80	17,310.79	13,928.92	609.28	3.49E+18	1.53E+17
Ordovician	0.08	1.44	89,864.53	69,121.46	5,737.08	1.73E+19	1.44E+18
Deadwood	0.07	0.51	32,828.78	16,895.82	1,098.23	4.24E+18	2.76E+17

Table 5. Mean accessible resource for reservoirs temperatures of 110 °C to 120 °C.

120° - 130°		Avg Thick	Area	Rock Volume	H_2O Volume	Energy R.	Energy W.
Fm or Sys	Porosity	km	km^2	km^3	km^3	Joules	Joules
Mississippian	0.15	0.21	12,801.13	2,671.34	400.70	7.82E+17	1.17E+17
Devonian	0.18	1.50	20,716.41	31,012.47	5,582.24	9.08E+18	1.63E+18
Silurian	0.04	0.80	21,092.80	16,972.07	742.39	4.97E+18	2.17E+17
Ordovician	0.08	1.44	75,131.87	56,207.52	4,665.22	1.65E+19	1.37E+18
Cambrian	0.07	0.51	35,890.81	18,471.74	1,200.66	5.41E+18	3.51E+17

Table 6. Mean accessible resource for reservoirs temperatures of 120 °C to 130 °C.

130° - 140°		Avg Thick	Area	Rock Volume	H_2O Volume	Energy R.	Energy W.
Fm or Sys	Porosity	km	km^2	km^3	km^3	Joules	Joules
Mississippian	0.15	2.10	16,303.79	34,156.44	5,123.47	1.14E+19	1.71E+18
Devonian	0.18	1.50	11,992.30	17,952.47	3,231.45	6.01E+18	1.08E+18
Silurian	0.04	0.80	11,813.75	9,505.79	415.80	3.18E+18	1.39E+17
Ordovician	0.08	1.44	56,034.90	46,685.80	3,874.92	1.56E+19	1.30E+18
Deadwood	0.07	0.51	25,234.26	12,987.19	844.17	4.34E+18	2.82E+17

Table 7. Mean accessible resource for reservoirs temperatures of 130 °C to 140 °C.

140° - 150°		Avg Thick	Area	Rock Volume	H_2O Volume	Energy R.	Energy W.
Fm or Sys	Porosity	km	km^2	km^3	km^3	Joules	Joules
Mississippian	0.15	0.21	1,297.43	270.75	40.61	1.02E+17	1.53E+16
Devonian	0.18	1.50	10,645.88	15,936.88	2,868.64	6.00E+18	1.08E+18
Silurian	0.04	0.80	10,018.81	8,061.51	352.63	3.03E+18	1.33E+17
Ordovician	0.08	1.44	30,143.10	28,215.98	2,341.93	1.06E+19	8.81E+17
Deadwood	0.07	0.51	16,168.21	8,321.21	540.88	3.13E+18	2.04E+17

Table 8. Mean accessible resource for reservoirs temperatures of 140 °C to 150 °C.

T ≥ 150°		Avg Thick	Area	Rock Volume	H_2O Volume	Energy R.	Energy W.
Fm or Sys	Porosity	km	km^2	km^3	km^3	Joules	Joules
Devonian	0.18	1.50	10,171.31	15,226.46	2,740.76	6.37E+18	1.15E+18
Silurian	0.04	0.80	2,446.98	1,968.93	86.12	8.23E+17	3.60E+16
Ordovician	0.08	1.44	26,906.27	22,279.67	1,849.21	9.32E+18	7.73E+17
Deadwood	0.07	0.51	11,217.19	5,773.09	375.25	2.41E+18	1.57E+17

Table 9. Mean accessible resource for reservoirs temperatures greater than 150 °C.

Fluid Volumes for Co-Production Geothermal Development

To assess the overall geothermal potential of the Williston Basin for geothermal fluids, we acquired fluid production data from the North Dakota Industrial Commission Oil & Gas web site (https://www.dmr.nd.gov/oilgas/). A critical issue in the Williston Basin is that wells are produced slowly to prevent watering out and consequently have low water-to-oil production ratios (WOR). The average WOR for 11,641 wells during July, 2014 in all formations in the basin was 3.4:1. The WOR for the Williston Basin is significantly different from the WORs for basins in Texas, Oklahoma and Louisiana, which can exceed 100:1. The overall WOR for the Williston Basin is skewed by data from 8,150 Bakken wells that have a WOR of 0.77:1. The Bakken (Ordovician/Mississippian) is a tight formation that can only be produced economically by hydraulic fracture of horizontal wells. Even excluding the Bakken, the WOR for the North Dakota portion of the Williston Basin is low, i.e., 9.8:1.

The greatest volumes of co-produced fluids are from the Madison (Mississippian) and the Red River (Ordovician) formations. The Madison lies at depths of approximately 3 km with temperatures of 100 °C to 110 °C. The Red River lies at depths of approximately 4 km with temperatures of approximately 130 °C to 140 °C. The total combined power production for the top ten producing wells in the Madison and Red River formations based on an exit temperature of 70 °C and an ambient air temperature of 10 °C (mean annual for ND) for an ORC with 6 percent efficiency would be approximately 700 kWh and 800 kWh respectively. Thus the volumes of co-produced fluids from individual wells in the Williston Basin are insufficient for economic development.

Unitized fields, which may include several tens of wells with common collection sites, produce enough fluid for development of several hundred kW installations, e.g., the Eland-Lodgepole field. Daily water production from all wells in the Madison and Red River formations in July, 2015 was 3,351 bbl/day and 8,861 bbl/day. Applying the same ORC parameters used for individual wells, we find that the total potential power for the unitized Madison and Red River fields amounts to only 3.9 MWh and 10.7 MWh respectively.

Power Generation from Multi-Well Pads in the Bakken Formation

Analysis of overall fluid production from active wells, units, fields and formations in North Dakota showed that few sites produce sufficient fluid for significant power production with ORC technology. All sites included in the analysis were conventional oil production sites, and as mentioned previously, the depth of the oil producing formations in the Williston Basin, typically 3 km or greater, requires that wells are produced slowly to prevent watering out. However, oil and water production data from the recent horizontal drilling boom in the Williston Basin reveal that infill drilling between Bakken and Three Forks horizontal wells has created areas where large volumes of geothermal fluids are available on multi-well pads and in unitized fields (Figure 16). Multi-well pads in the Bakken and Three Forks have increased fluid production at an exponential rate since February, 2011 (Figure 17). Production for seven fields among 24 fields shown in Figure 16 reached 409,795 barrels of fluid per month in September, 2014. Production has dropped with the drop in oil prices and was 326, 511 barrels in January, 2015. According to ORC manufacturers (Ormat, Pratt & Whitney, TAS, Fuji Electric) the oil and water mix produced at the well head can be sent through the heat exchanger. Thus the full volume of produced fluid can be used for power generation. Bakken temperatures in the high production areas are on the order of 120 ^{0}C to 130 ^{0}C depending on depth (Figure 18).

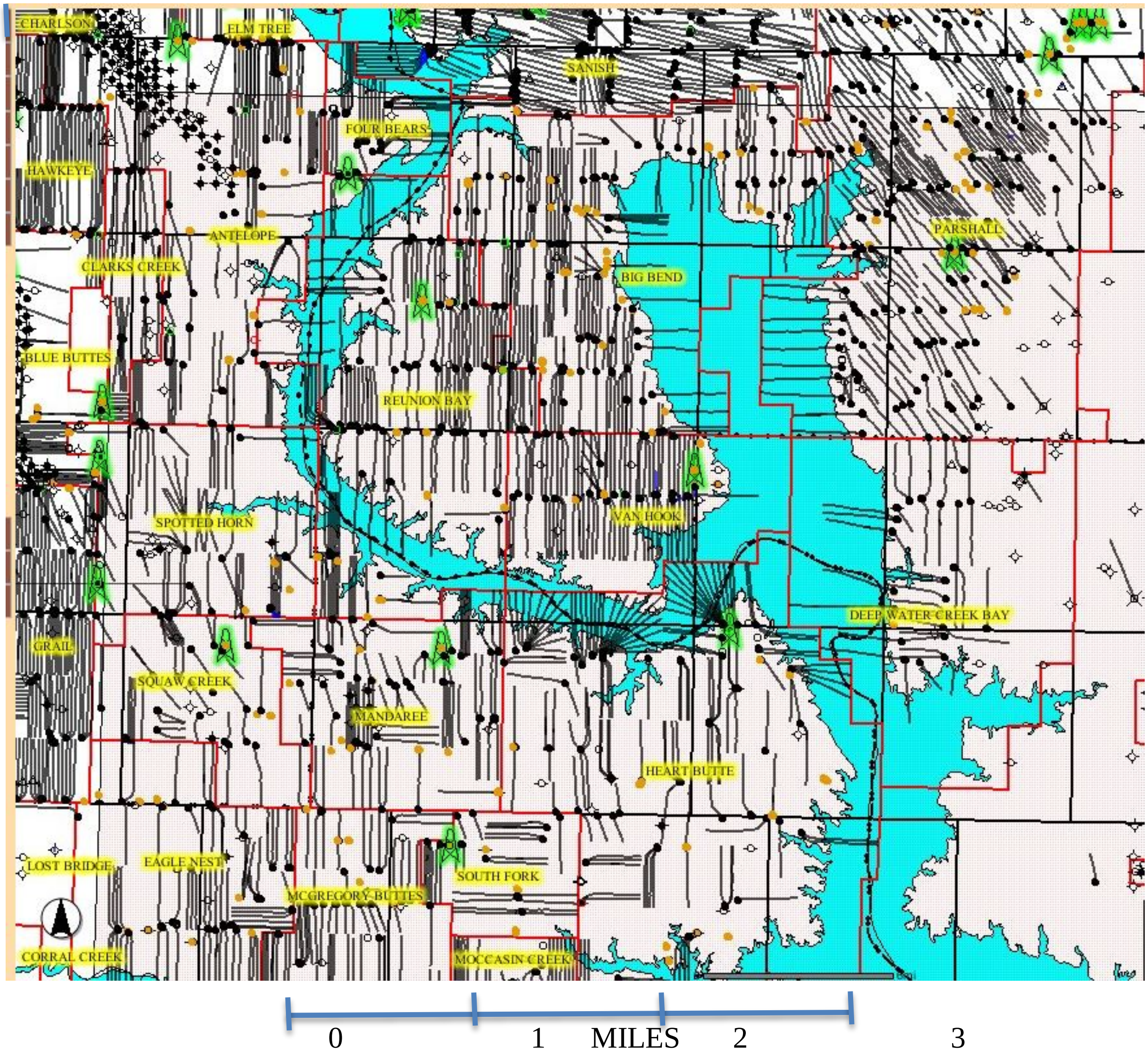


Figure 16. Horizontal wells in Bakken formation shown by black lines which are drawn to scale. Highlighted text identifies individual fields.

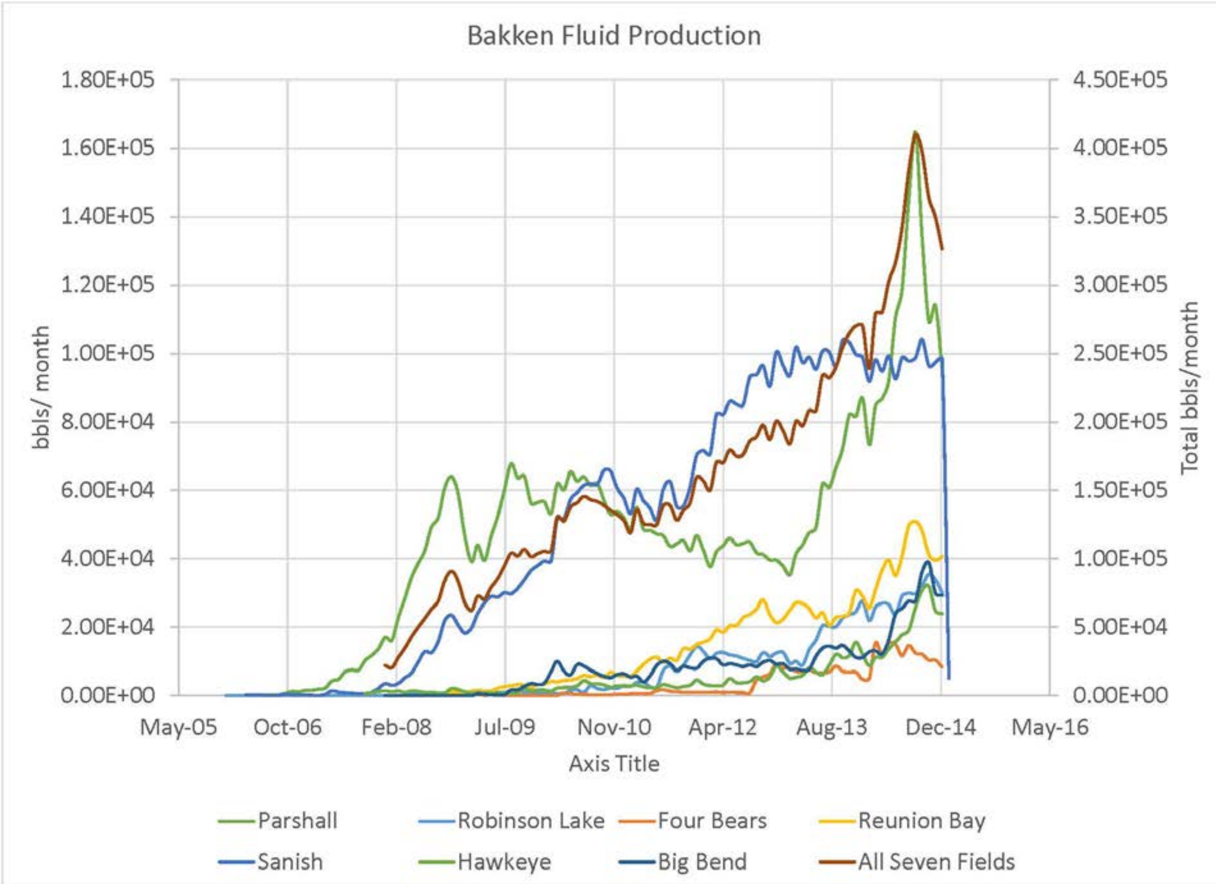


Figure 17. Total fluid production for seven Bakken oil fields among the 24 fields shown in Figure 16. Data are from the North Dakota Industrial Commission Oil and Gas website https://www.dmr.nd.gov/oilgas/feeservices/stateprod.asp Individual field volumes are indicated on the left vertical axis and the total volume is indicated on the right vertical axis.

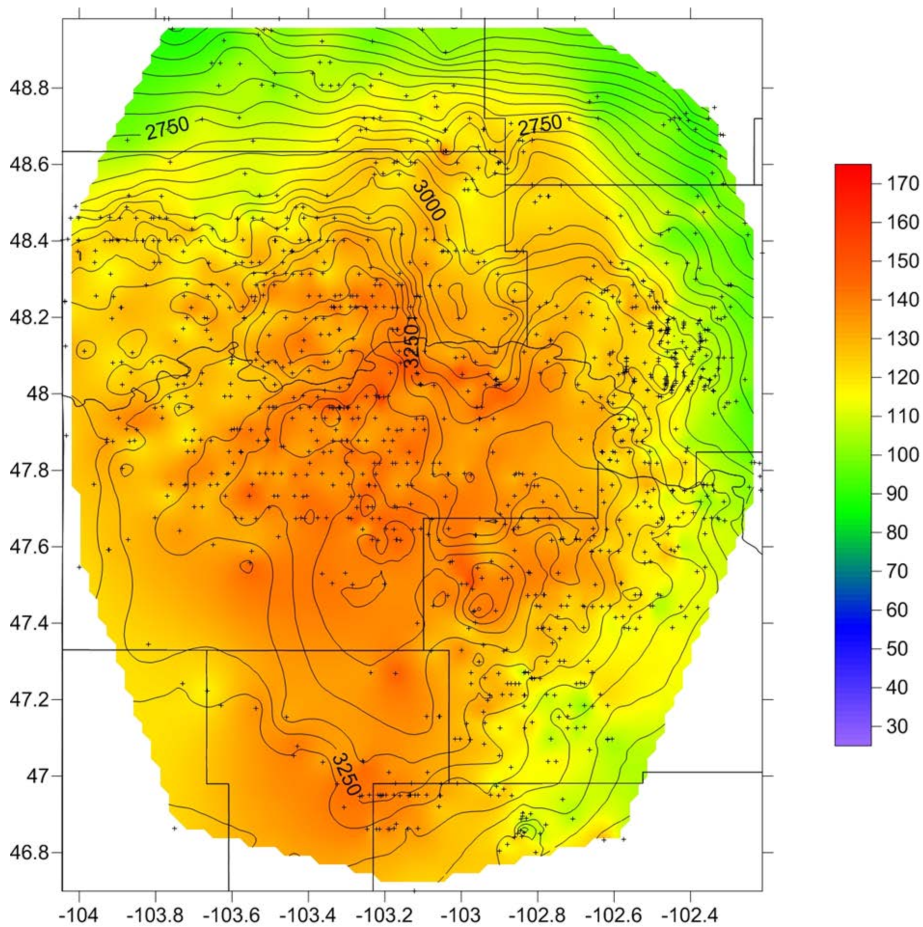


Figure 18. Temperature (colors) and depth (contours) for the Bakken Formation.

Opportunity and Impact of Bakken Development

The North Dakota Industrial Commission has estimated that approximately 2,600 MW of additional power will be required to produce the Bakken and Three Forks oil by 2032. The power supply for the North Dakota's conventional oil fields is provided by six coal-fired power plants located along the Missouri River (Figure 19). Currently, the petroleum industry is using diesel and propane powered generators and some operators are using produced gas to drive generators on site. The cost of the on-site electricity is more than five times the cost of electricity from the power grid. The conventional approach to adding new power would be to construct new coal or gas-fired power plants along the Missouri River and build thousands of miles of new transmission lines. The time required to build the new generation capacity and transmission infrastructure could be more than a decade. However, the need for this power and the grid to deliver it will exist only for the life of the Bakken and Three Forks plays which are projected to be 20 to 30 years. When the drilling phase for Bakken and Three Forks development is completed in 15 to 20 years, the oil-field service population of western North Dakota will decline to near pre-boom levels thus further reducing post-boom power demand.

Some of the Bakken-Three Forks fields lie within the existing power grid, but many producing fields lie outside the existing infrastructure and rely on propane or diesel fuel to run generators for electrical power. A distributed ORC network could preclude construction of new fossil fuel burning power plants and the construction of a power grid that will be unneeded when the Bakken oil boom ends. Production of the 2,900 MW by geothermal power could avoid generation of approximately 10 million metric tons of CO_2 that would be generated by burning lignite at the six currently operating coal-fired power plants in western North Dakota. We propose that this is a major opportunity to use scalable ORC systems in an oil and gas setting. Adoption of the ORC technology would impact development of the Bakken and Three Forks production in several ways. First, it would provide mobile, low-cost, distributed electrical power to the oil fields that would result in large cost savings for oil production. Second, it would avoid the construction of additional coal-fired power plants and an extensive electrical grid that would become useless when the oil plays end in a few decades. Third, avoiding construction of additional coal-fired power plants would eliminate additional production of approximately 10 million metric tons of CO_2.

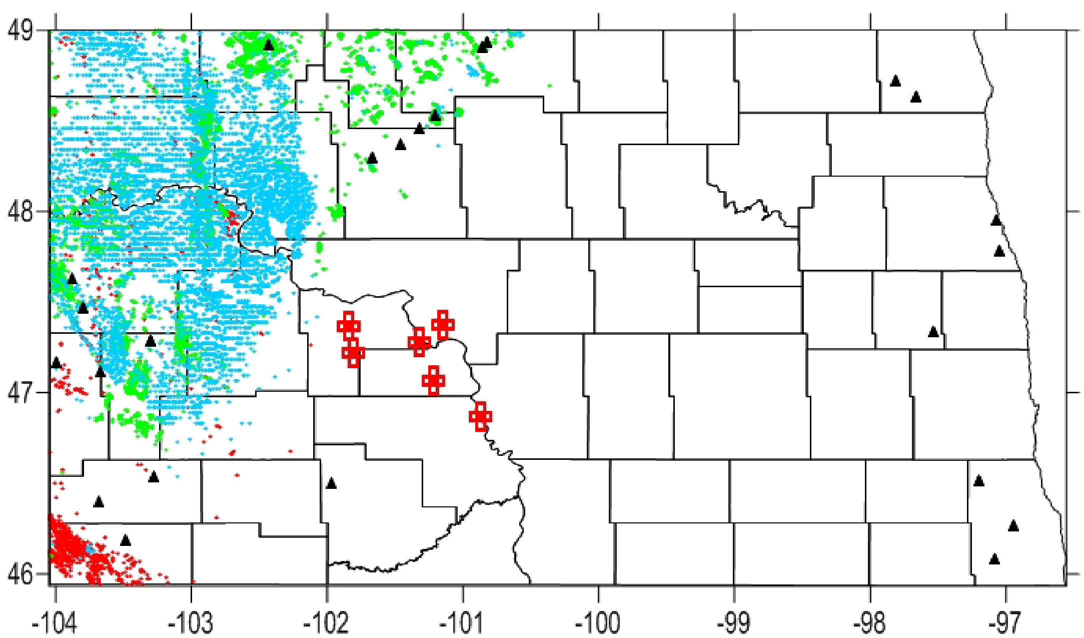


Figure 19. North Dakota oil wells, heat flow sites and power plant locations. Blue dots indicate Bakken-Three Forks wells, red dots indicate Red River wells, and green dots indicate Madison wells. Open red crosses indicate power plants and black triangles indicate heat flow measurements.

A New Perspective – Horizontal Geothermal Drilling

The water flood operation at the CLR site adds a new perspective for geothermal development in a sedimentary basin. Conventional development would be vertical wells drilled into geothermal aquifers. Drilling open-hole lateral wells within a relatively flat or gently dipping geothermal aquifer greatly increases the volume of water that can be produced. An intriguing possibility would be to drill 6 to 8 laterals radially from a single pad. Three moderately high temperature aquifers in the Williston Basin, the Deadwood (Cambrian), Red River (Ordovician), and Madison (Mississippian) offer potential for this type of development. The rocks are competent and laterals can be open-hole, i.e., without lateral casing, and they are permeable enough to yield significant amounts of water. Figures 20, 21, and 22 were developed from the National Geothermal Data System (NGDS) bottom-hole temperature data for North Dakota and show the temperatures and depths for these formations.

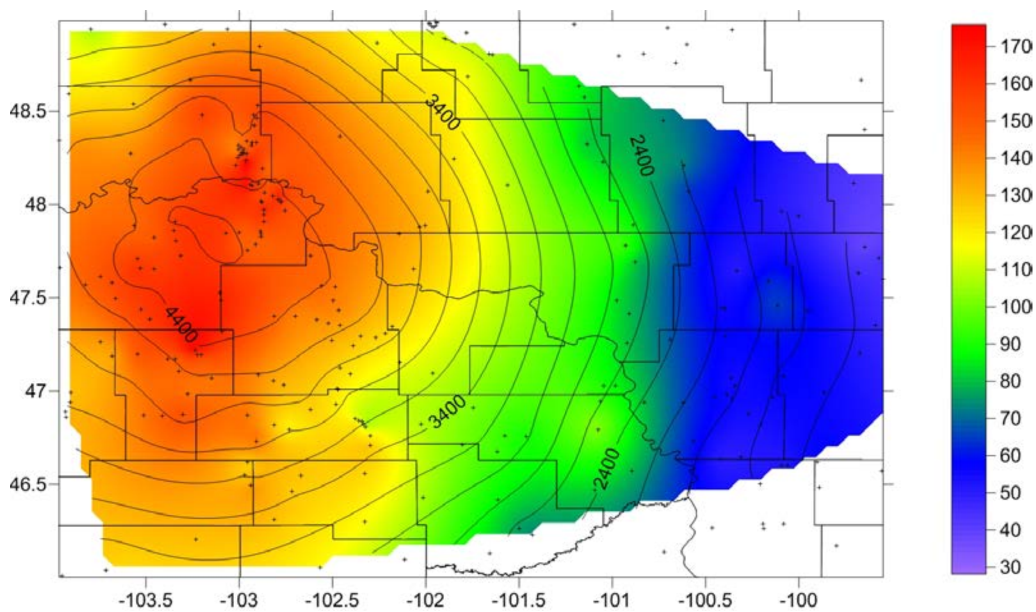


Figure 20. Temperature (colors) and depth (contours) for the Deadwood Formation.

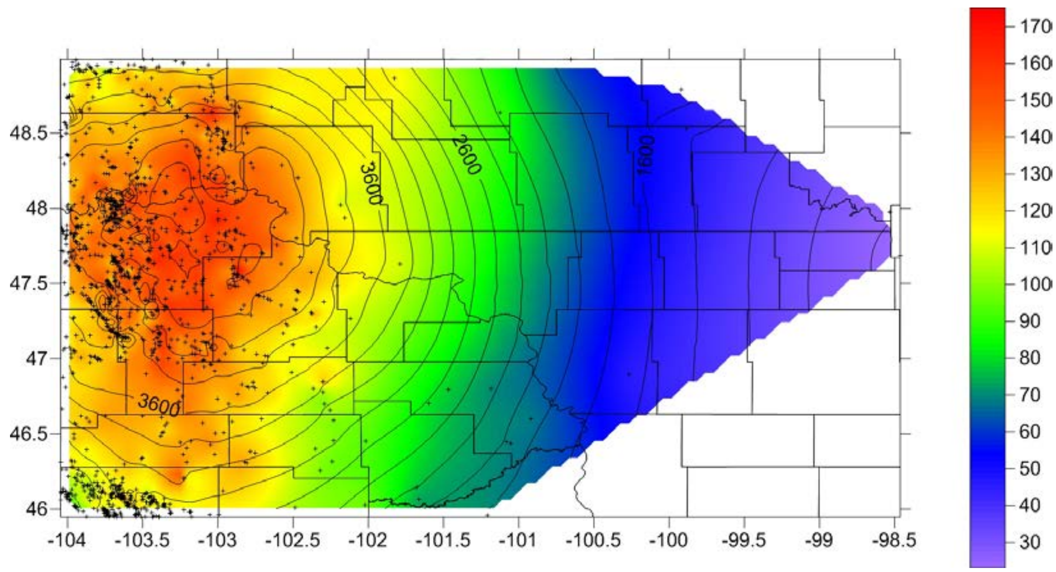


Figure 21. Temperature (colors) and depth (contours) for the Red River Formation.

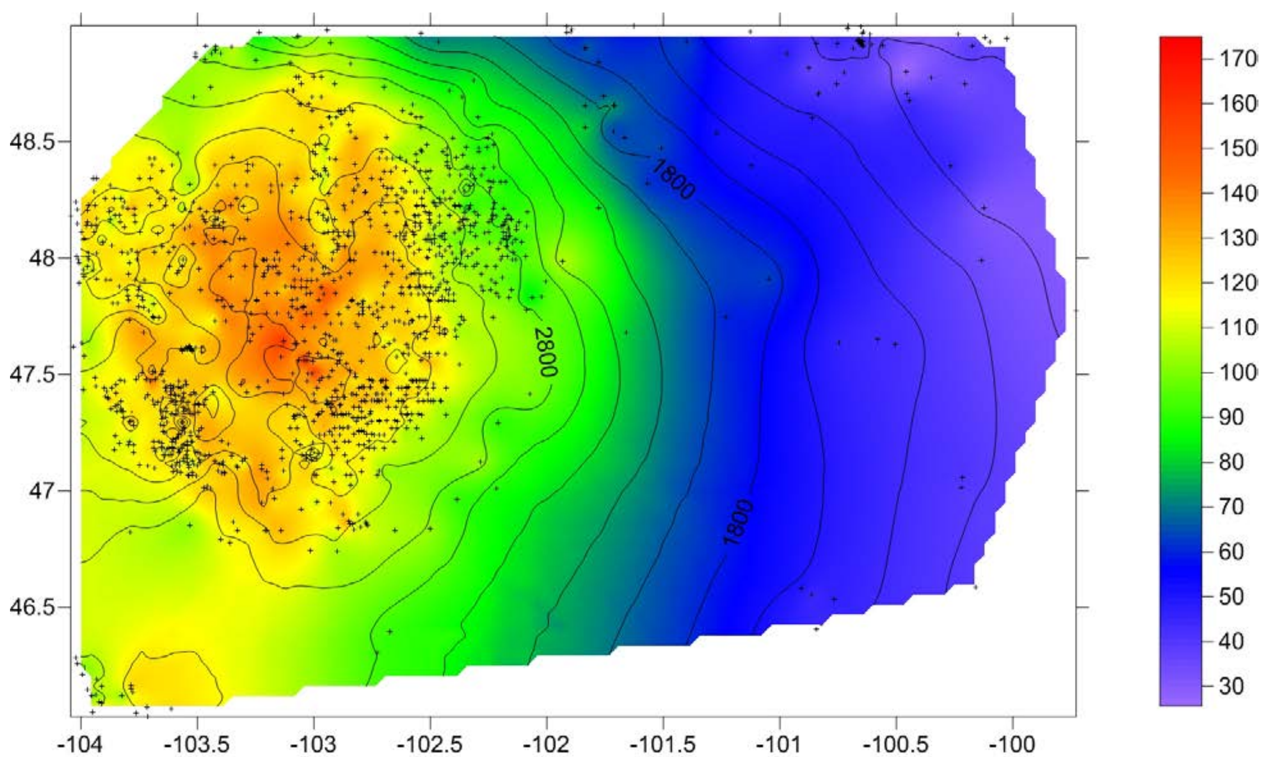


Figure 22. Temperature (colors) and depth (contours) for the Madison Formation.

The ORC system

We analyzed six commercially available ORC systems based on the available fluid volume and temperature to determine the economic feasibility for co-produced and low-temperature geothermal development. The key parameters are available fluid volume, fluid temperature, and ambient air temperature. The analysis favored the ORC system designed by Access Energy, LLC although several of the other systems, e.g., Ormat and Pratt and Whitney (P & W), rated well. The overall efficiency of ORC systems is of the order of 6 to 10 percent with 6 percent being the expected operational performance. Due to innovative design and engineering the Access Energy machines currently operating with temperatures above 120 °C are 14 percent efficient. The Access Energy System, selected for the UND projects is rated to produce 125 kW for fluid temperatures of 95.6 ^{0}C and above. The system was developed specifically for the UND demonstration project by modification of a 50 kW system that operated with fluids at 135 ^{0}C. Characteristics of the system are: 125 kWe gross, 3-phase, 380 to 480 V L_L, frequency 50.60 Hz, and the working fluid is R245fa. The Integrated Power Module (IPM) contains a turbine expander and generator. It is hermetically sealed and uses magnetic bearings for high-efficiency. The design elements that favor the Access Energy ORC include the use of magnetic bearings and installation of magnets in the fan blades of the turbine. Thus the ORC has only one moving part and achieves a significant reduction in parasitic mechanical load. The power that could be produced at the Eland-Lodgepole site with a P&W Pure Cycle 200, 8 percent efficiency, is estimated to be 350 kW. We estimate the power production of the Eland-Lodgepole field using Access Energy equipment with 12 percent efficiency would be approximately 568 kW.

Summary for Objective 2

Generating electricity economically from oil field fluids, either co-produced water or the complete oil and water mix, depends on the capacity to concentrate sufficient volumes of fluid at a power plant site. Formation temperatures in deep aquifers in the Williston Basin are adequate for power generation with binary systems, but the widely distributed wells in the main water producing formations, Madison and Red River, cannot concentrate sufficient quantities of water to generate economic amounts of power. However, the rapid development of multi-well pads in the Bakken and Three Forks has led to localized production of large volumes of fluids at 120 ^{0}C to 130 ^{0}C and many of the Bakken oil fields could provide enough fluid to generate several hundred MW of power. The water flood operation at the CLR site adds a new perspective for geothermal development in sedimentary basins in that the water supply wells were completed as kilometer-long open-hole laterals which greatly increases the volume of water that can be produced.

Analysis of overall fluid production from active wells, units, fields and formations in North Dakota showed that few sites produce sufficient fluid for significant power production with ORC technology. All sites included in that analysis were conventional oil production sites. Due to the depth of the oil producing formations in the Williston Basin, typically 3 km or greater, pumps are operated slowly to prevent watering out thus total fluid production is purposefully maintained at low volumes. However, analysis of the NDGS production data reveal that infill drilling between Bakken and Three Forks horizontal wells has created areas where large volumes of geothermal fluids are available on multi-well pads and in unitized fields. Multi-well pads in the Heart Butte Bakken Unit have increased fluid production at an exponential rate since February, 2011. Current production is approximately 37,317 bbl/day and it is estimated that this fluid production could generate approximately 2 MWe at the Heart Butte Unit.

The future need for 2,600 MW of additional power to produce the Bakken and Three Forks oil could be met with a distributed power network of ORC units. We propose that this is a major opportunity to use scalable ORC systems in and oil and gas setting. Adoption of the ORC technology would impact development of the Bakken and Three Forks production in several ways. First, it would provide mobile, low-cost, distributed electrical power to the oil fields that would result in large cost savings for oil production. Second, it would avoid the construction of additional coal-fired power plants and an extensive electrical grid that would become useless when the oil plays end in a few decades. Third, avoiding construction of additional coal-fired power plants would eliminate additional production of approximately 1,000 tons of CO_2 per year.

Suggested Steps in Implementing a Distributed ORC System in an Oil Producing Basin

Based on our experience in this project, we suggest that the sequence of steps in implementation of a low-temperature geothermal application in oil and gas settings should be:

1. Establish Goals
    a. Determine power production needs or requirements
2. Site Identification
    a. Access the NGDS database for temperature, depth, fluid quantity and fluid quality and select an area for potential development.
    b. Contact operating oil companies
    c. Contact electric utilities
    d. Contact regulating agencies
3. Arrange to visit potential sites with the field operator and representatives of the electric utility and the regulating agencies.
4. Develop contractual agreements between all parties.
5. Design power plant/facility and select vendors

Objective 3. Dissemination of Results and Training of Future Geothermal Workers

Objective 3 of the project was highly successful. The program has produced 5 PhDs, 7 MS, and 3 BS students with theses in geothermal energy. The team has involved 7 faculty in 4 different engineering and science disciplines, ChE, EE, GE, and Geol. The team has produced 26 peer-reviewed papers and 62 presentations at professional meetings. Faculty involved in the program developed five graduate level courses covering different elements in heat flow and geothermal energy that are now offered in the Harold Hamm School of Geology and Geological Engineering. A major link between this project and the UND Petroleum Research, Education, and Entrepreneurship Center (PREEC) provided matching funds and personnel for some aspects of the project. Funding for PREEC was from the North Dakota Department of Commerce Centers of Excellence program and development of geothermal power in North Dakota is one of the missions of the Center.

Faculty Involved in the Project:

P.I. Will Gosnold, Chester Fritz Distinguished Professor
Harold Hamm School of Geology and Geological Engineering
Director of the UND Petroleum Research, Education, and Entrepreneurship Center (PREEC)

Co-P.I. Michael Mann, Chester Fritz Distinguished Professor, Chemical Engineering
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Co-P.I. Hossein Salehfar, Professor, Electrical Engineering
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Dongmei, Wang, Assistant Professor
Harold Hamm School of Geology and Geological Engineering
Research Scientist-Engineer on PREEC and co-author on a GRC paper

UND Geothermal Laboratory

Support from the North Dakota Department of Commerce in matching funds for geothermal resource development was provided for software and equipment purchases and upgrades of existing equipment. With the combined support from NDDC and DOE we have formally established the University of North Dakota Geothermal Laboratory. The laboratory includes seven faculty representing three academic departments: Geology and Geological Engineering – 3, Chemical Engineering – 2, Electrical Engineering 1.

Equipment on hand – none of this equipment was purchased by the DOE award. It was all acquired through other grants during the past 30 years and is used in research and education for students in the UND program.

2 Portable Electronic Divided Bars (PEDBs), built by Hot Dry Rocks Ptd Ltd in Australia

- Small, portable, able to be used in the lab or in the field
- +/- 2% accuracy
- 0.5 to 12 W/mK range
- Samples up to 65mm diameter
- 10, 15 or 20º C temperature differential
- Readings in as little as 5 minutes

2 Stationary Divided Bars

- Agilent 34970A data logger
- 2 Polyscience circulating baths
- Temperature ranges from -20ºC to 150ºC
- Pressures up to 10,000 psi for insitu condition replication
- Hot and cold circulating baths accurate to 0.1ºC constant temperatures
- Double thermocouples at all points for accuracy and error checking

Lacoste and Romberg Gravity meter

- Accuracy is in the range of 1 to 10 microgals

96 channel geophone array, built by Geometrics

- 4 "Geodes" with 4 sets of cables (500 m total)
- 96 geophones

- ultra-high resolution 20 kHz bandwidth (8 to 0.02 ms sampling), low distortion (0.0005%), low noise (0.2uV), stacking accuracy (1/32 of sample interval)
- Reflection processing software (WinSeis-Lite)
- Reflection: Suitable for shallow reflection, deep reflection, 2-D and 3-D surveys
- Refraction: Comes with built-in first break picking and analysis

Seismic gun: The BOSS

- The Ballistic Ordnance Seismic Source (The BOSS) - patented
- Uses standard 12 gage shotgun slugs
- Portable wheeled design also carries other seismic array equipment
- Quiet, safe and consistent

Gamma ray spectrometer, built by Canberra

- 2 liquid nitrogen tanks
- DSA1000 signal analyzer
- Germanium-Lithium scintillation detector

Magnetometer, built by Geometrics

- G-856 Memory Mag proton precession magnetometer
- Resolution: 0.1 nT
- Accuracy : 0.5 nT
- Gradient Tolerance: 1000 nT/meter

2 High resolution GPS receivers, built by Trimble

- Stand-alone antenna for sub centimeter accuracy

Temperature probe

- 867 meters of cable
- 0.009ºC accuracy
- 0.001ºC resolution

MS Students and Thesis Topics

Robert Klenner (BS UND)	Heat Flow and Geothermal Energy in Minnesota (2011)
Godswill Njoku (BS Nigeria)	Climate Signal in Heat Flow (2013)
Eric Zimny (BS UND)	Radioactive Background of Home Stake Mine (2014)
Aaron Ochsner(BS UN-Omaha)	Heat Flow and Groundwater flow in NW Nebraska (2014)
Caitlin Hartig (BS Penn State)	Balance between Natural and Stimulated Fractures for Energy Extraction (2015)
Faye Ricker (BS U. Fla.)	Geothermal Regime of the Williston Basin in North Dakota (2015)
Dylan Young (BS UND)	Uranium, Thorium and Potassium Contents of Rocks in the Northern Black Hills, South Dakota (2016)

PhD Students and Topics

Anna Crowell (MS UND)	Geothermal Resource Assessment of Mid-continent Sedimentary Basins (2011)
Josh Crowell (MS UND)	Thermal Conductivity of Williston Basin (2015)
Mark McDonald (MS UND)	Geophysical Investigation of Rye Patch KGRA (2013)
Samir Dahal (MS Sri Lanka)	Geothermal Electric Power from Binary Power Plants (2013)
Kirtipal Barse (MS India)	Analysis of Binary Power Systems (2013)

As a result of interest in geothermal energy we have proposed the following courses for a program of study in geothermal energy. These courses are taught by faculty in HHSGGE. Faculty in our new department of Petroleum Engineering offer relevant classes in geomechanics, drilling and reservoir analysis that support the geothermal program.

Program of Study in Geothermal Energy

GEOL 450 Global Tectonics The course explores the development of global tectonics since the formulation of plate tectonics in the 1960s. Earth's large-scale structural elements, their origins, compositions, deformation styles and histories and the methods of study are presented as an integrated system. The course concludes with the implications of global tectonics for all Earth systems.

GEOL 551 Heat Flow An exploration of Earth's thermal structure, thermal history and heat sources. The course begins with the theory of heat transfer within and through the surface of terrestrial planets. Methods of observation and modeling provide hands-on experience in field and laboratory activities. Applications of heat flow in tectonics, petrology, thermal maturity of kerogen, hydrogeology, geothermics and climate change are presented with current examples.

GEOL 552 Intro to Renewable Energy The course explores the four major methods of renewable and/or sustainable energy production; solar, wind, hydro and a special emphasis on geothermal. Topics such as world energy supplies, current popular methods of power production, infrastructure, passive versus active power production, intermittent versus base load, characterizing and locating feasible areas for each of the different methods, and economic viability will be discussed.

GEOL 560 Geothermics I A survey of the methods of geothermal exploration, assessment and production. The course covers the various methods for discovery and characterization of geothermal resources. Methods for assessment of energy in place and determination of recoverable energy are covered in depth. Current technologies for energy extraction and power production are presented with current examples.

GEOL 561 Geothermics II The course covers the historical development of geothermal policies, regulations and practices globally and in different states within the US. Matters of water usage, contamination and disposal are covered extensively. Current issues such as induced seismicity, hydrofracture, power plant size and location, electrical grid access and land use are critically examined.

Publications, Presentations, and Abstracts - this list covers 2012-2015

The following list of publications, presentations, and abstracts have enhanced UND's reputation in geothermal and petroleum industries:

Publications by UND Geothermal Team

1. Crowell, A. and W. Gosnold, Integrating Geophysical Data in GIS for Geothermal Power Prospecting, Geological Society of America Publication: GEOSPHERE, Accepted for Publication, 2015.
2. Crowell, J., Measuring Thermal Conductivity Using a Divided Bar: Equations for Irregular Samples, Geological Society of America Publication: GEOSPHERE, Accepted for Publication, 2015.
3. Crowell, J. and A. Crowell, The History of Lightning Dock KGRA: Identifying a Blind Geothermal Resource, Transactions of the Geothermal Resources Council, vol. 38, p. 77-83, 2014.
4. Gosnold, W. and A. Crowell, Heat Flow and Geothermal Research in Mid-Continent of North America, Transactions of the Geothermal Resources Council, vol. 38, p. 127-131, 2014.
5. Crowell, A. and W. Gosnold, Geothermal Resource Assessment of the Michigan and Illinois Basins: How Deep is Too Deep?, Transactions of the Geothermal Resources Council, vol. 38, p. 947-949, 2014.
6. McDonald, M. and W. Gosnold, Gravity Modeling of the Rye Patch Known Geothermal Resource Area, Rye Patch, Nevada, Transactions of the Geothermal Resources Council, vol. 38, p. 533-539, 2014.
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22. Ricker, F. and W. Gosnold, Characterization of Radiogenic Heat Production from Basement Rocks and Its Relationship to Heat Flow in the Williston Basin and North Dakota, Stanford Geothermal Workshop, Stanford, CA, February 2015.
23. Crowell, J., Measuring Thermal Conductivity Using a Divided Bar: New Equations for Irregular Samples, Geological Society of America Annual Meeting, Vancouver, BC, October 2014.
24. Crowell, A. and W. Gosnold, Mapping Optimum Locations for Geothermal Power Production: Colorado, Illinois, Michigan, Nebraska, and North Dakota, Geological Society of America Annual Meeting, Vancouver, BC, October 2014.
25. Majorowicz, J., J. Chan, J. Crowell, W. Gosnold, L. Heaman, J. Kuck, G. Nieuwenhuis, D. Schmitt, M. Unsworth, N. Walsh, and S. Weides, WCSB Geothermal: Where it is hot and where it is not – A Review of Geothermal State of the Foreland Basin, Geological Society of America Annual Meeting, Vancouver, BC, October 2014.
26. Dahal, S., and H. Salehfar, Optimal Location and Sizing of Distributed Generation in Distribution Networks, accepted for publication IEEE Transactions on North American Power Symposium 2013, Manhattan, KS, September 2013.
27. Crowell, A. and W. Gosnold, Utilizing Geophysical Data and GIS to Identify Areas of Interest for Geothermal Power Production: Denver-Julesberg Basin, Colorado, North Dakota GIS Users Conference, Grand Forks, ND, September 2013.
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29. Crowell, A., and W. Gosnold, Recoverable Thermal Energy for Geothermal Power Production in the Denver Basin, SMU Geothermal Conference: Geothermal Energy and Waste Heat to Power—Utilizing Oil and Gas Plays, Dallas, TX, March 2013.
30. Gosnold, W., and K. Barse, Status of the North Dakota Oil Field Geothermal Projects, SMU Geothermal Conference: Geothermal Energy and Waste Heat to Power—Utilizing Oil and Gas Plays, Dallas, TX, March 2013.
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Conclusions

Generating electricity economically from oil field fluids, either co-produced water or the complete oil and water mix, depends on the capacity to concentrate sufficient volumes of fluid at a power plant site. Formation temperatures in deep aquifers in the Williston Basin are adequate for power generation with binary systems, but the widely distributed wells in the main water producing formations, Madison and Red River, cannot concentrate sufficient quantities of water to generate economic amounts of power. However, the rapid development of multi-well pads in the Bakken and Three Forks has led to localized production of large volumes of fluids at 120 ^{0}C to 130 ^{0}C and many of the Bakken oil fields could provide enough fluid to generate several hundred MW of power. The water flood operation at the CLR site adds a new perspective for geothermal development in sedimentary basins in that the water supply wells were completed as kilometer-long open-hole laterals which greatly increases the volume of water that can be produced.

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