LOW-TEMPERATURE SEDIMENTARY GEOTHERMAL EXPLORATION

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ABSTRACT

Low-temperature geothermal energy is an opportunity for the geothermal industry to expand beyond traditional high-temperature regions and to work with other industries to enhance both reservoir exploration knowledge and surface technology designs. Oil and gas fields are opportunities to apply new data for low-temperature projects. Coproduction of these related fluids has few production projects online, yet because of the waste-heat to power industry, the necessary conversion technologies have continued to improve with temperatures of 82°C able to generate power. Induced seismicity, primarily from injection fluids into formations below the oil and gas shale plays is a problem for the oil industry. These low-temperature opportunities overlap with potential sites for enhanced geothermal systems, and now provide additional modeling constraints to better understand stresses and reactivation of faults in the basement for the geothermal community to learn and use to our advantage.

1. INTRODUCTION

The ability to extract and use the heat stored in sedimentary formations offers an expansion of development for geothermal resources. These formations with a history of oil and gas drilling are often in areas considered low-temperature (<150°C) and of these resources, often they are drilling into formations with temperatures <100°C. The research completed during the past decade by the SMU Geothermal Laboratory has looked at opportunities and solutions to examine how these formations can be developed to expand the geothermal community's accessible resources.

2. HEAT FLOW DATA FROM OIL AND GAS FIELDS

The knowledge about where low-temperature resources are located was significantly expanded with the incorporation of oil and gas bottom-hole temperature measurements. The first large collection of these data dates back to the 1970s American Association of Petroleum Geologists Geothermal Survey and COSUNA datasets (AAPG, 1994). This dataset enhanced the details of the 2004 Geothermal Map of North America (Blackwell and Richards, 2004). The use of oil and gas data to expand our knowledge of resources for geothermal energy production is now common across the United States. The reverse is also true: the oil and gas industry is the number one user of the Geothermal Map of North America and related heat flow and temperature files.

The addition of oil and gas bottom-hole temperature (BHT) data and then accompanying lithology logs, results in changes to previous regional heat flow mapping. First, the mapped heat flow changes from generalized geologic mapping for areas with limited data, to highly varied heat flow values fluctuating over short distances (Figure 1). As a result there is an increase in identified areas of higher heat flow for further research. These changes are because of greater data density and deeper well data. For example, the area in and around West Virginia in the previous 1992 and 2004 Geothermal Map of North America (Blackwell and Steele, 1992; Blackwell and Richards, 2004), only three heat flow data points were available; thus the heat flow was mapped consistent with the surrounding area geology, with considerations for the Appalachian Highlands. After adding 1,249 oil and gas BHT points to the West Virginia dataset and using the COSUNA lithology sections, we were able to define a higher heat flow zone within the Appalachian Basin (Figure 1) (Frone and Blackwell, 2010; Frone et al., 2015). Further research was completed on the Appalachian Basin as part of the Department of Energy Play Fairway Basin projects examining the ability to extract the heat for direct use of the fluids in heating buildings (Jordan et al., 2015). This study determined areas for further exploration in New York, Pennsylvania, and West Virginia for use for deep direct use applications, primarily commercial buildings or industrial use of the sedimentary formation heat of 50 –150°C.

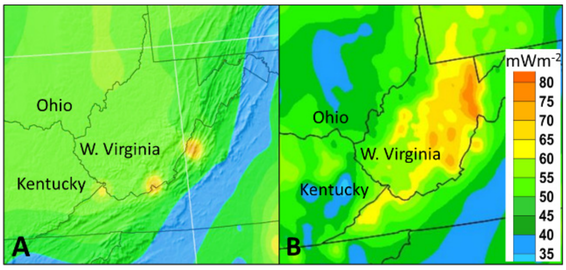

Figure 1: Map of the heat flow within the vicinity of West Virginia (WV). A) The 2004 heat flow contours determined from a few heat flow data points and the geologic trends. B) The 2011 heat flow values calculated from 1,249 oil and gas bottom-hole-temperature data points. Additional research by Frone et al. (2015) determines the heat flow in 2011 as too high based on new heat generation models. Thus for B, heat flow contours in WV should be between 50 and 70 mWm^{-2}, and as variable as shown in B.

The original continental scale – regional heat flow map (Blackwell and Steele, 1992) was comprised of 13,300 well data points from detailed temperature logs and rock thermal conductivity measurements. Of these data point, 89% of them are < 500 meters in depth and 65% of them are < 152 m, therefore, the map is primarily based on shallow measurements. Contrasting to this is the 2011 United States heat flow map (Blackwell et al., 2011) that included the addition of 35,000 oil and gas BHT data points with an average depth of 1960 m. As a result, the 2011 map is approximately 10 mWm^{-2} higher heat flow in the Appalachian Basin, Gulf Coast, and Northwestern Great Plains, all three areas mapped using the additional oil and gas BHT data (Figure 2). The reason for this generalized increase in heat flow is not fully understood. As more opportunities for research are available, considerations are as follows: Are the corrections to the oil and gas BHT too high and/or are the assigned thermal conductivities for the stratigraphic column not accurately represented? Are depths of < 152 m not deep enough to be representative of the regional conductive heat flow in sedimentary basins? Are water flow patterns transporting heat from one area along faults increasing or decreasing temperatures at the near surface? Is the long term climate change impacting the shallow readings (Gosnold et al., 2011)? The original heat flow values were properly calculated, therefore this as an opportunity to reassess best practices for collecting new heat flow measurements. In using the increased data density from the oil and gas data we learned that the basement rock types vary more than was originally mapped in 1992 by Blackwell and Steele (Batir et al., 2011; Frone et al., 2015).

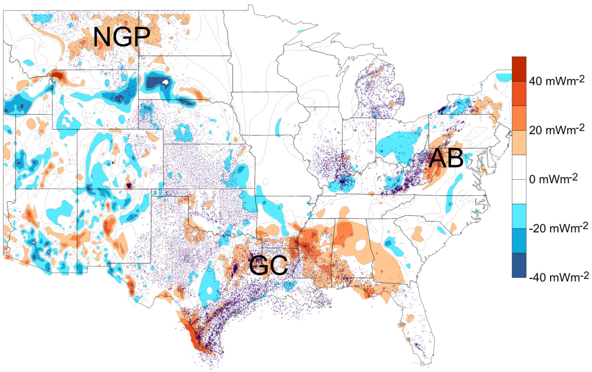

Figure 2. Map of Heat Flow Differences between the 1992 SMU - DNAG Heat Flow map (Blackwell and Steele, 1992) and 2011 SMU – Heat Flow map (Blackwell et al., 2011). 1992 used primarily equilibrium data and 2011 included oil and gas bottom-hole temperature data (plotted as purple). Area in warm colors (orange – reds) represent a higher heat flow in 2011. AB – Appalachian Basin, NGP – Northwestern Great Plains, GC – Gulf Coast.

3. OIL AND GAS INDUSTRY SOLUTIONS

Oil and gas data have been tremendously helpful in our study of low-temperature geothermal resources, filling in large regional data gaps, providing detailed field studies, geophysical logs as calibration tools, and cores for thermal conductivity measurements.

Equilibrium temperature measurements from high precision logs have been an industry standard for correcting the bottom-hole temperature (BHT) datasets for determining the accurate reservoir temperatures. In working with very large datasets, e.g., the 2011 SMU Oil and Gas BHT data, SMU used the Harrison Correction for consistency across all basins (Blackwell et al., 2011). When it is possible to write a specific basin temperature correction, this is the preferred method. Another source of measurements are the oil and gas well pressure-temperature log, representing in-situ reservoir temperature values. As part of the reservoir management tools, operators collect static well pressures at multiple depths in a well throughout the life of the well. These temperatures have been usually overlooked by both the geothermal and oil and gas industries. The pressure values are used by the oil and gas industry yet the temperatures are rarely reviewed (Hunt Oil, personal communication, 2012). A study on Fairway Field in East Texas highlights how both the high precision temperature logs and pressure-temperature logs from Hunt Oil Company align (Figure 3) (Kweik et al., 2014). In this reservoir, the BHT data are under corrected if the Harrison Correction is used, showing the need for individual basin correction models incorporating pressure-temperature log and equilibrium temperature logs.

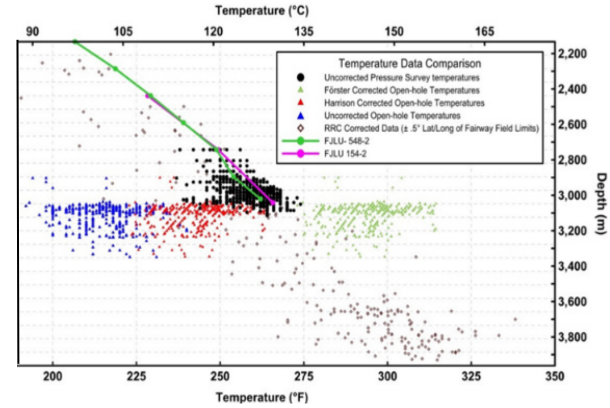

Figure 3. Fairway Field, Texas BHT data and applied temperature corrections (triangles of blue – original, red – Harrison, green – Förster) compared with the pressure-temperature data (black dots) and Hunt Oil high precision temperature logs FJLU-548-2 & 154-2 (Kweik et al., 2014).

Results from this same study in Fairway Field, East Texas (Kweik et al., 2014) displayed how the produced water temperatures are slightly increasing over the 50 years of production by approximately 10 °C (Figure 4). The geologic setting of this field is a turtle shape or half dome, thus what is expected to be occurring is the decrease in formation pressure as the fluids are being produced at approximately 3000 m, causes the fluids from below to flow upward to fill in the low pressure, thus causing warmer fluids to flow upward.

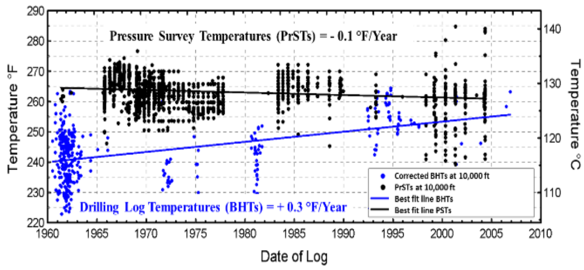

Figure 4. Corrected bottom-hole temperature data at 3000 m from drill logs (blue). Corrected pressure log temperatures at 3000 m (black) (Kweik et al., 2014).

In working with low-temperature sites, the initial exploration using BHT data can be misleading if the wells under consideration are high in gas content. The conversion of a gas well to geothermal energy can become too cool for electrical production because of the gas expansion cooling the fluid as it rises to the surface. For instance, on the University of West Virginia MSEEL well-site, the fluid temperatures from 2134 m are reaching the surface at only 18.3°C where typical BHT values range from 50 to 58 °C (Paul Ziemkiewicz, Personal Communications, 2016).

4. INDUCED SEISMICITY CONCERNS

We have more to learn from the oil and gas industry with their current problem of induced seismicity. In the United States there is an increase in the number of induced seismicity events occurring in the shale plays associated with oil and gas production and wastewater injection. The state of Oklahoma now has more earthquakes in a year than the state of California. In 2015, there were 888 magnitude 3+ earthquakes (OK Government, 2016), causing the Oklahoma

Geological Survey to conclude that the majority of recent earthquakes in central and north-central Oklahoma are very likely triggered by the injection of produced water into disposal wells (OK Government, 2016).

In comparison, Texas in 2015 had 21 earthquakes (USGS, 2016), yet this is still an exponential rise in events from pre 2008 numbers before the rapid development of the Barnett Shale. SMU seismologists have documented the relationship between wastewater disposal and triggered seismic activity (Figure 5) (Hornbach et al., 2016). The induced earthquakes in the Barnett Shale of the Fort Worth Basin are generated from an increase in reservoir pressures over a 10 year period, such that the volume of fluid injected increases pore fluid pressure within the entire formation by 0.09 MPa. In specific locations near wastewater injection wells, elevated fluid pressures ranging from 1.7 to 4.5 MPa above hydrostatic in the Ellenburger formation promote failure on pre-existing faults, even tens of kilometers away, in the Ellenburger and the basement below (Hornbach et al., 2016). The earthquakes are being generated by movement along faults ‘lubricated’ by the injection fluids moving from the carbonates into previous fault structures, often in the basement (King, 2015).

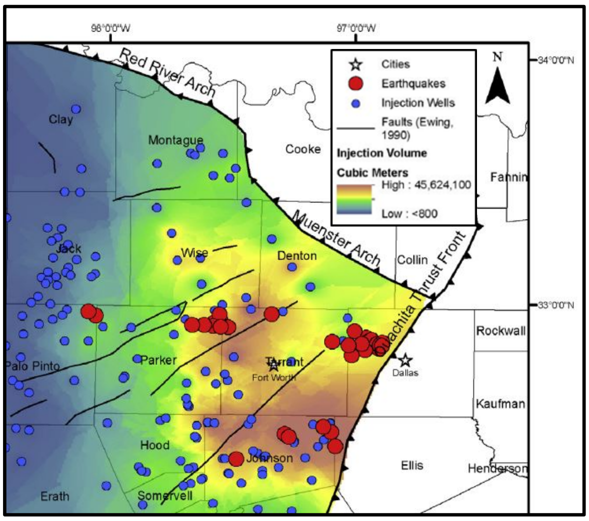

Figure 5. Locations of earthquakes and injection wells within the Barnett Shale in the Fort Worth Basin, North, Texas. Zones of increased wastewater injection (blue dots) have felt earthquakes (red dots) along preexisting faults, although not previously mapped as active faults (black lines) (Hornbach et al., 2016).

The geothermal industry cannot dismiss the possibility of induced seismicity when developing sedimentary formations, especially if they are intending to drill close to or through the sedimentary formations into the basement. The carbonate formations, e.g., Ellenburger, below the oil and gas shale plays in Central and Eastern United States (Loucks, 2015) contain the necessary temperatures and the highest porosity and permeability making it the most likely candidate for initial enhanced geothermal systems (EGS) projects (Figure 6) (Richards and Blackwell, 2012).

The shale plays have created many highly fractured reservoirs with the horizontal drilling from a single pad, i.e., 22 wells from one pad to extract from 1100 acres below the city of Arlington, Texas (King, 2016). Within the Barnett Shale play there are over 25,000 wells permitted because of the ability to horizontal drill (Texas RRC, 2016). The discussion of EGS in sedimentary formations has suggested starting with the sediments, then as drilling is economically feasible moving into the deeper basement rocks to increase the possible heat extraction (Tester et al., 2006). Modeling the balance of fluids and the pore pressure changes within and around the EGS reservoir is recommended if concerned about induced seismicity (Hornbach et al., 2016). In addition, the oil and gas industry are developing new techniques to identify and avoid known pre-existing faults using new seismic reflection methods (Sun et al., 2015), such that an analysis of regional seismic reflection data can reveal fault location and orientations combined with pressure/stress tests in regional wells to determine the likelihood of fault movement (Hornbach et al., 2016). The geothermal community will also make decisions for how to mitigate to avoid these pre-existing faults or learn how to use them to their advantage in expanding an EGS project as part of the production and injection of fluids within a geothermal reservoir.

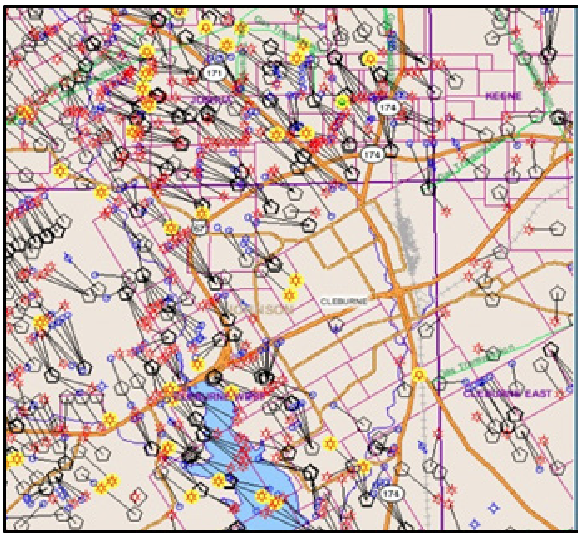

Figure 6. Map of surface well sites (open circle) and related horizontal legs (black lines) below the Dallas-Fort Worth, Texas area (yellow lines are major city roads) highlighting the densely fractured Barnet Shale formation (Texas Railroad Commission GIS Online Map).

5. OIL FIELD PROJECTS

The discussion of low-temperature geothermal development has two arms, one directly using the coproduced fluids as produced from the fields today, or to increase the amount with new casing perforations; the second using the field knowledge to reduce development costs for geothermal exploration for either off-grid energy sites or direct-use applications. Coproduction is limited by the production formations of the oil and gas industry producing the majority of their fluids at < 100°C and from many wells at a lower than geothermal rate.

5.1 Technology Solutions

Since our first conference in 2006 on Utilizing Geothermal Energy in Oil and Gas Fields, the SMU Geothermal Laboratory network continues to assist technology companies as they develop and demonstrate their low-temperature technologies. The focus on a ‘new’ geothermal, low-temperature resource energized the industry in 2005 with the development of the UTC PureCycle® water-cooled binary machine (Table 1). Once two units were installed at Chena Hot Springs, Alaska, in 2006 using the 74°C well water to generate 400 kW net power, we had companies from the wind industry contacting us, looking for the next big renewable energy development. Yet they did not have enough below-ground knowledge to get projects developed. Ormat Technologies in 2008 demonstrated their 250 kW air-cooled binary machine, using ~88°C fluids, installed at the Rocky Mountain Oilfield Testing Center in Wyoming. This was an opportunity to showcase how the oil and gas industry could produce fluids that were usable by the geothermal community and save the oil and gas industry from abandoning their wells, or better yet, they could add to their revenue stream with coproduction of well fluids to generate on-site power. We expected opportunities to be found across the oil fields of the Gulf Coast because of the heat flow displayed by the Geothermal Map of North America (Blackwell and Richards, 2004). At the same time, the oil and gas industry was full-on in drilling the shale plays, and little time for geothermal discussions.

SMU in 2008 demonstrated the ElectraTherm Inc. Green Machine 50 kW with Gulf Coast Green Energy using a screw technology to generate power from the temperature drop between two fluids in our campus boiler room. It was next demonstrated on the Denbury Resources Mississippi CO2 flood field in 2009, highlighting the importance of remote access to the control panel for these small units running very close to the efficiency cut-off point daily in the hot summer temperatures. Their machine is now the Power + Generator with units 35 kW, 65 kW, 110 kW. One of the first companies to use oil and gas fields for their fluids was Deluge Inc, now Cornerstone Sustainable Energy, who continue to improve on the concept, with today their PwrCor™ technology uses the physical expansion of heated fluids at 82°C to drive a piston and generate 125 kW or 250 kW. At this temperature, the ability to use the majority of produced fluids by the oil and gas industry is possible (McKenna and Blackwell, 2005).

A current demonstration in North Dakota of the Calnetix Technologies LLC - Access Energy Thermapower® ORC uses a Continental Resources water flood operation designed with two 125 kW integrated units. This is the first time to use a water flood injection site, rather than focusing on coproduction (National Driller, 2016). The Thermapower® technology is licensed by GE (General Electric) for waste-heat applications.

It is the waste heat applications that kept many of these innovative technologies improving while the geothermal community has lagged in successful projects in sedimentary basins (Loy Sneary, Personal Communications). The same equipment can be used for capturing the heat off engines and heat from the produced fluids in the oil and gas field. Thus a lesson learned by SMU Geothermal Lab is the value of working with multiple industries while expanding into a new geothermal resource. Eight SMU Geothermal conferences on Geothermal Energy from Oil and Gas Fields have been held. There are many papers and presentations available through the conference website (http://smu.edu/geothermal).

Table 1. SMU Timeline of Geothermal - Oil & Gas Focus

1975 Texas Geothermal Resources Act written

1989 First Geopressure power plant in the US, Brazoria County, TX

2004 SMU completes Geothermal Map of North America

2005 UTC builds prototype of PureCycle® (now under PWPS)

2005 Steve Bergman & SMU "discover" RMOTC's high fluid flow

2006 Chena Hot Springs, AK develops geothermal power (500 kW)

2006 1st SMU Geothermal Conference on Utilizing Oil & Gas Fields

2008 ORMAT Technology installs binary unit at Rocky Mtn Oilfield Testing Center, WY

2008 ElectraTherm, Inc. demonstrates Green Machine on SMU Campus in Dallas, Texas

2009 Texas H.B. 4433 Hydrocarbon Tax Exemption from Severance Tax for Geothermal Wells

2009 RPSEA awards project to Gulf Coast Green Energy & Denbury Resource in central MS

2009 DOE Geothermal program funds o/g projects in ND, TX, LA

2010 Oregon Institute of Tech. powers-up with PWPS PureCycle®

2010 DOE Geothermal Low-Temperature "Road Mapping" plan established

2011 North Dakota research project compares all current binary technologies for oil field settings and presents at SMU Geothermal Conference in June

2011 SMU completes the Google funded Geothermal Map of the United States highlighting many more areas for exploration

2012 China producing 400 kW electricity from Huabei Oilfield

2013 New National Geothermal Database System includes most state oil and gas data for geothermal project research

2013 TAS installs 1 MW ORC in Bakersfield, CA field

2014 Production Tax Credit $0.023 for geothermal projects with "commenced construction" prior to January 1, 2015

2015 Hess Corporation & HARC demonstrate conversion of flare gas to power using ElectraTherm Power+ technology

2016 Continental Resources produce 250 kW power from injection water using Calnetix ORC near Marmarth, ND

2016 SMU 8th Conference Power Plays: Geothermal Energy in Oil and Gas Fields, the majority of attendees from Oil and Gas.

CONCLUSION

The geothermal industry in the United States has explored and developed power plants ever since the 1950s. The industry has yet to be able to expand geothermal power beyond western United States in a commercially successful manner. Incorporating the oil and gas industry knowledge of sedimentary basins from their exploration and production experience is an opportunity for the geothermal community to develop geothermal resources in these same basins. New surface technologies allow conversion of lower temperature fluids than the industry has previously required for project success in western United States. These technologies are providing small-scale (≤ 1 MW), potentially distributed, opportunities to be considered as part of a new geothermal business model.

At the same time, the sedimentary basins may also be the answer for the geothermal community to learn techniques, which then opens the door to enhanced geothermal systems. The current success of the oil and gas industry's horizontal drilling and mapping of fracture patterns with microseismicity presents cross-overs for geothermal engineered reservoirs. The related potential for induced seismicity highlights new concerns that must be proactively managed in these engineered systems.

These low-temperature resources may provide the catalyst to move beyond western United States and see geothermal energy play a significant role in the United States energy grid.

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