Can Deep Stratigraphic Reservoirs Sustain 100 MW Power Plants?

Rick Allis[1] and Joe Moore[2]

[1]Utah Geological Survey, Salt Lake Survey, UT
[2]Energy & Geoscience Institute, University of Utah, UT
rickallis@utah.gov • jmoore@egi.utah.edu

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ABSTRACT

Petroleum exploration wells confirm that the high permeability and high flow rates needed from geothermal production supporting large-scale power development can be found in deep stratigraphic reservoirs (> 3 km depth). Data from drilling in the Rocky Mountains and Great Basin of western U.S. show carbonate reservoirs at depths of 3 – 5 km have slightly better average permeability than siliciclastic reservoirs (75 versus 30 mDarcies). These values are sufficient for high-flow-rate geothermal production wells. Deep wells in two Rocky Mountain basins also show that carbonate reservoirs, possibly dolomitic, can preserve high permeability when the temperatures are 220 - 240°C at more than 5 km depth. There may be a relationship between widespread, good stratigraphic permeability, and reservoirs being at hydrostatic pressure. If true, this may imply that over-pressure is a negative indicator for a large geothermal reservoir. Conventional oil well production flow rates are usually significantly lower than that required for geothermal power production, but this is due to oil viscosity being at least ten times higher than hot water, rather than low permeability reservoirs. The target conditions for stratigraphic geothermal reservoirs are temperatures of 175 - 200°C and depths of 3 – 4 km. These conditions can be found within basins where the heat flow is about 90 mW/m^2, the average heat flow for the Great Basin. The eastern Great Basin is underlain by a lower Paleozoic carbonate section that ranges up to 3 km in thickness and is known to have good permeability. Numerous reservoir targets where temperatures are 175 - 200°C at depths of 3 – 4 km, and good stratigraphic permeability is known or inferred have been identified in the Great Basin. The large areas of these reservoirs (~ 10^2 to 10^3 km^2) can each support power plants of more than 100 MWe.

Introduction

The onshore area of high heat flow in the U.S. (> 80 mW/m^2) is large by global comparisons, with individual high-heat-flow areas exceeding ~10^4 km^2 present in the Great Basin, Snake River Plain, Oregon Cascades, and Southern Rocky Mountains-Rio Grande Rift (Tester et al., 2006). Most growth in installed geothermal capacity in the U.S. over the last decade has been from binary plants with installed capacities averaging 25 MWe (GEA, 2014). Between 2013 and 2015 the Energy Information Agency (EIA) expects the growth in power generation from solar to be 50% per year, that of wind to be 6%/year, and geothermal to be 2%/year, with total wind generation being ten times that of solar or geothermal power in 2015 (EIA, 2014; the installed capacity of wind will be 76 GWe). In future decades, the development of enhanced geothermal systems (EGS) is expected to contribute ~10 GWe of power capacity (Ziagos et al., 2013; Jeanloz and Stone, 2014), but until that technology becomes economically viable, where will future growth in geothermal power production in the U.S. come from? Will we see geothermal power plants that are ~100 MWe in scale, similar in size to the wind and solar projects presently being constructed? Most of the accessible, economically attractive, hydrothermal systems have been tapped, and blind hydrothermal systems are both challenging to find and tend to have relatively small reservoirs (Blackwell et al., 2012).

Allis et al. (2012, 2013) have suggested that sedimentary geothermal reservoirs may be a bridge between conventional hydrothermal systems that dominate the present 3.5 GWe of installed capacity in the U.S., and future EGS developments. These stratigraphic reservoirs are sub-horizontal and in high-heat-flow basins; the conductive thermal regime means temperatures approach 200°C at 3 – 4 km depth (Figure 1). In contrast to hydrothermal systems, which in the Great Basin have areas 1 – 10 km^2, stratigraphic reservoirs can have areas comparable to the area of the basin (10^3 to 10^4 km^2), which is the primary reason for their attractive potential. Also, in contrast to EGS, which require the reservoir to be created by fracturing low permeability host rocks, stratigraphic reservoirs have the necessary permeability.

The reservoir volume needed to sustain a 100 MWe geothermal power plant is large, and critically depends on the heat sweep efficiency. Grant and Garg (2012) and Garg and Combs (2010) have pointed out that naturally fractured reservoirs appear to have heat recovery factors of 5 – 15%, and for some EGS projects the heat recovery decreases to a few percent. Tester et al. (2006) suggest that 5 km^3 of reservoir is needed to sustain a 100 MWe binary plant for 20 years. This assumes 20% heat sweep efficiency. If the heat sweep efficiency is between 10 and 20%, and the power plant has an economic life of 30 years, the reservoir volume is between 7 and 25 km^3. If most of the heat is being swept from a 500 m thick stratigraphic sequence and the heat sweep efficiency is about 15%, then the area of the reservoir is about 30 km^2. This is similar to the stratigraphic reservoir modeling of Deo et al. (2014), which suggests a conservative, sustainable, 3 MWe/km^2 power generation rate for large-scale binary power developments.

Most geothermal production wells around the world are between 1 and 3 km depth. Drilling for a stratigraphic reservoir at 3 to 4 km depth is presently considered overly risky and economically unviable. The two major uncertainties hindering deeper exploration and development are 1: doubt that production wells will have the required permeability and flow rate at these depths; and 2: concern that the well field will be capable of producing economically attractive power (< 10 c/kWh) using today's development costs. The first uncertainty is the subject of this paper, and the second is the subject of a companion paper (Mines et al., 2014).

Target Depth of Stratigraphic Reservoirs

A compilation of thermal regimes in the U.S. in Figure 1 depicts the two regions, defined as high- and moderate-temperature hydrothermal systems, and situated between 1 and 3 km depth. It also shows the thermal regime in selected low- to moderate-heat-flow basins frequently drilled for oil and gas. Between the petroleum exploration basins and traditional hydrothermal systems is the regime of stratigraphic geothermal systems. The low temperature limit for the target zone of stratigraphic reservoirs in Figure 1 is defined by the most optimistic economic models yielding a levelized cost of electricity of 10 c/kW/h discussed by Mines et al. (2014). This ranges from 150°C at about 2 km depth to 200°C at about 4 km depth. The limit of 2 km and 150°C requires excellent permeability and a relatively slow rate of reservoir temperature decline during 30 years of production. While not impossible, a more realistic range of target reservoir properties is 3 – 4 km and 175 - 200°C, which is what Mines et al. (2014) use for their economic scenarios. There is an upper temperature limit of about 200°C irrespective of depth based on existing pump technology. So far, we have identified at least 8 locations in the eastern Great Basin where the temperature-depth characteristics of wells indicate possible stratigraphic resource potential (labeled on Figure 1).

A more general depiction of the different types of geothermal system, typical petroleum systems, and target stratigraphic reservoirs is shown in Figure 2a. Two important thermal constraints are highlighted: the gap between pumped reservoirs less than 200°C, and self-discharging wells common in high-temperature systems with temperatures above about 220°C (Sanyal et al., 2007); and the brittle-ductile transition that becomes important above about 330°C and causes a loss in permeability. The target stratigraphic geothermal reservoirs have many geological characteristics of petroleum reservoirs, but they are hotter, and they are deeper than typical moderate temperature hydrothermal systems. The temperature range overlaps with that of "high pressure – high temperature" (HPHT) gas reservoirs that are an active area of research with some petroleum teams (Pinto et al., 2013; Terrell, 2012). Another version of the relationship with petroleum systems in temperature-pressure space in shown in Figure 2b using Schlumberger's definition of HPHT systems. Stratigraphic geothermal reservoirs have pressures similar to conventional oil and gas, but the temperature range extends into the field of high temperature

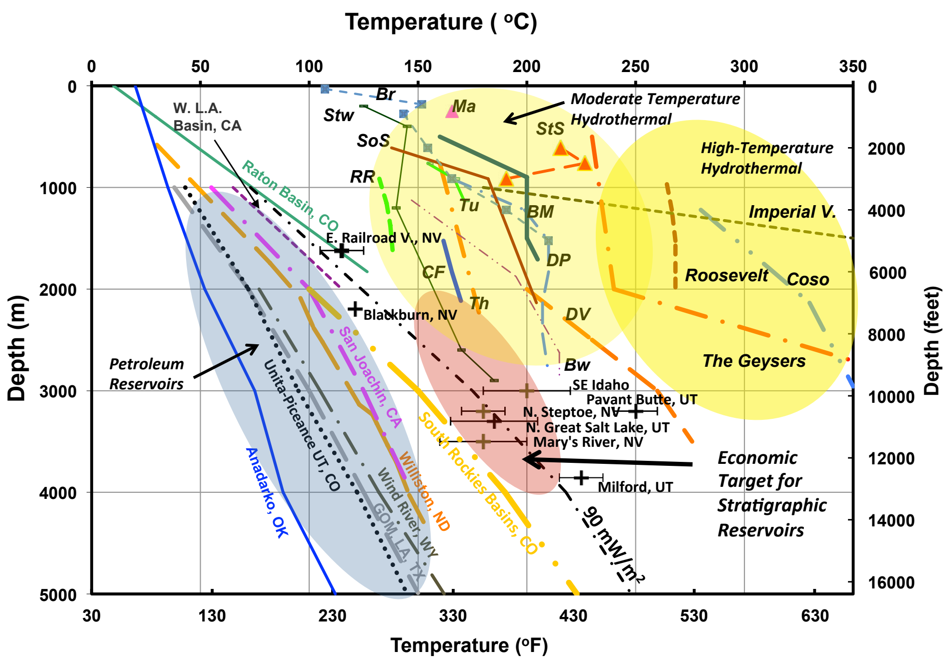


Figure 1. Compilation of U.S. thermal data from hydrothermal reservoirs (yellow and light yellow zones), selected major basins containing petroleum reservoirs (light blue zone), and the economic target for stratigraphic reservoirs in high heat-flow basins confirmed by Mines et al., (2014; purple zone). A geotherm for 90 mW/m^2 is superimposed assuming thermal conductivities representative of less consolidated sediments overlying consolidated carbonate and siliciclastic formations. For simplicity, one temperature-depth point (+ symbols) is shown for basins identified so far by Moore and Allis, (2013) as having a thermal regime that satisfies the target stratigraphic reservoir zone. The Southern Rockies Basins that graze the lower edge of the target zone include the eastern Piceance (Wilson et al., 2003) and western Denver-Julesberg (Anderson, 2013; Crowell and Gosnold, 2013) basins where they abut against the higher heat of the Rocky Mountains physiographic province. Abreviations for the moderate temperature hydrothermal systems (all are in the Great Basin) are: Stw, Stillwater, NV; Ma, Mammoth, CA; StS, Steamboat Springs, NV; SoS, Soda Springs, NV; Tu, Tuscarora, NV, BM, Blue Mountain, NV; DP, Desert Peak, NV; CF, Cove Fort, UT; Th, Thermo, UT; Tu, Tuscarora, NV; DV, Dixie Valley, NV; Bw, Beowawe, NV; Br, Bradys, NV; RR, Raft River, ID. Other abbreviations are: L.A., Los Angeles Basin; GOM, Gulf of Mexico onshore (Louisiana) and offshore (TX).

petroleum systems. There should be some cross-over research applications between HPHT petroleum systems and stratigraphic geothermal systems. Delineating reservoir-seal sequences is a sophisticated process in petroleum exploration and has application to stratigraphic geothermal reservoirs; however, understanding the implications of high temperature fluid-rock interactions on permeability is well known in geothermal geoscience, but may be a cutting-edge area development of HPHT petroleum systems.

Permeability

With stratigraphic reservoirs, the main permeability is within specific geological formations, which in a basin usually means the permeability is nearly horizontal. In hydrothermal systems, the primary permeability allowing the upflow of hot water is usually fault-controlled and frequently sub-vertical. Numerical modeling of sedimentary reservoir-seal sequences suggests that the transmissivity (permeability-thickness) needs to be in the range of 3 – 10 Darcy-meters to avoid excessive pressure decline around production wells (Deo et al., 2014). This modeling also shows that the heat sweep efficiency, and therefore the long-term geothermal power potential, of the reservoir is much improved if there are multiple, thinner high permeability layers in a reservoir-seal sequence, rather than one thick layer of high permeability with the same overall transmissivity. A single high permeability layer allows a more rapid thermal break-through and leaves stranded heat in the reservoir, analogous to the short-circuiting of water in a fracture within a hydrothermal system. The modeling assumed four 25 m thick layers of 30 – 100 mDarcy as the reservoir, sandwiched between 1 mDarcy "seal" layers of variable thickness within a 300 reservoir-seal "sandwich".

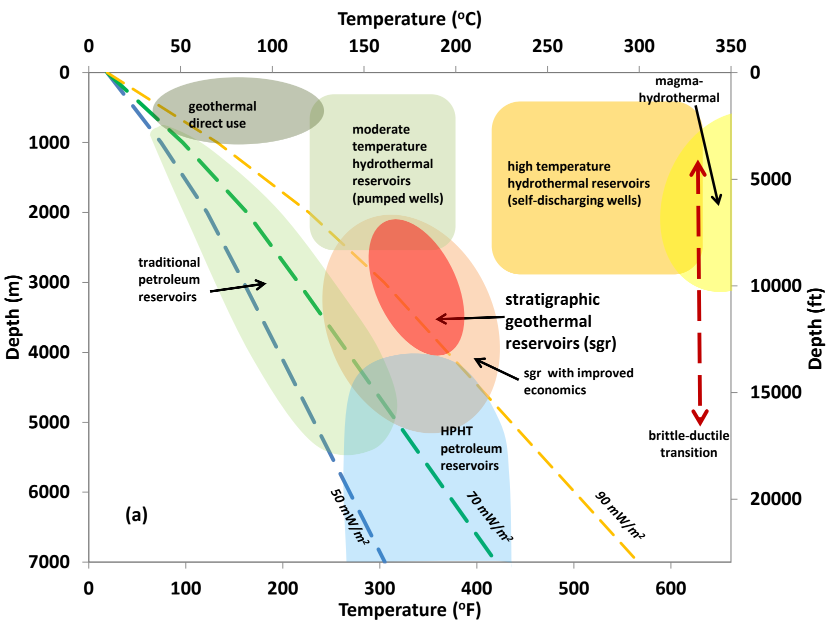


Figure 2a. Types of geothermal and petroleum systems based on their temperature-depth characteristics.

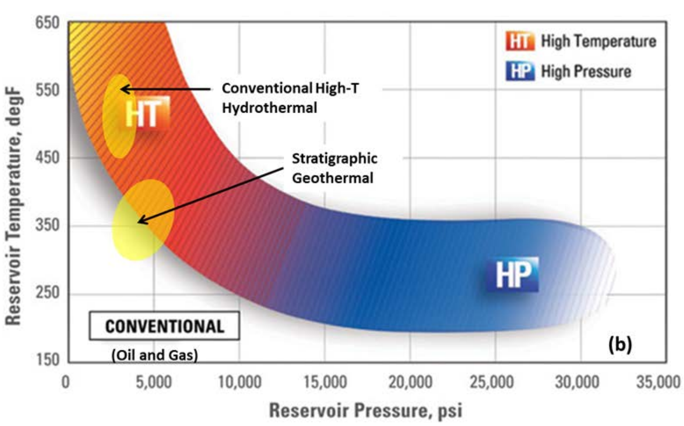
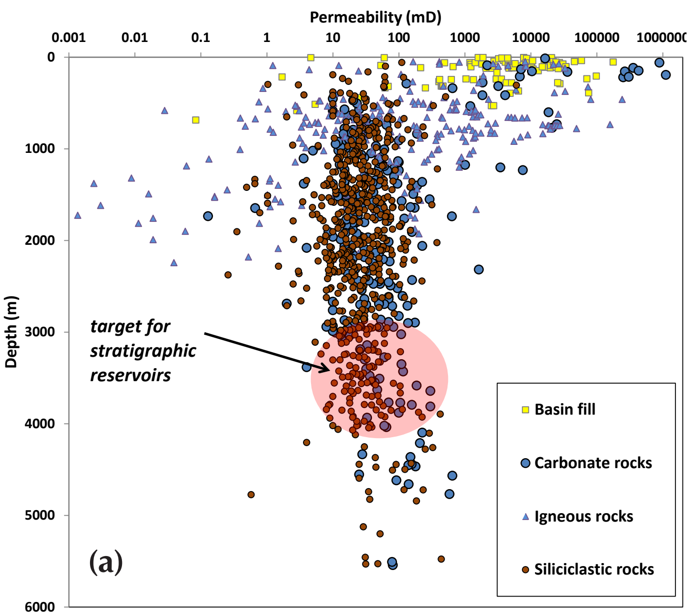


Figure 2b. Conventional hydrothermal and stratigraphic geothermal reservoirs superimposed on the field of HPHT oil and gas reservoirs in temperature-pressure space (modified from www.schlumberger.com, accessed 4/20/2014). Stratigraphic geothermal reservoirs usually have pressures close to hydrostatic (Allis, 2014; gradient of ~ 0.4 psi/foot), whereas deep petroleum reservoirs tend to be over-pressured, and some reservoirs approach a lithostatic gradient (~ 1 psi/foot). For metric conversions, 1 MPa is 10 bars and equal to 145 psi; 200°C is 392°F.

Evidence from permeability tests in petroleum reservoirs confirms that permeabilities in the range of 30 – 100 mDarcy are not uncommon at depths greater than 3 km (Figure 3a). Kirby (2012) compiled permeability measurements from the western U.S. and found the mean permeability between 3 and 5 km depth is 75 mDarcy for carbonates, and 30 mDarcy for siliciclastics. There is no evidence in this dataset that permeability decreases with depth between 1 and 6 km depth with these two lithologies. However, there is a strong trend of decreasing permeability with depth in igneous rocks (volcanics and intrusives; most data is less than 2.5 km depth), most likely due to the mixed mineralogy of igneous rock and their sensitivity to alteration and plugging of permeability. Clean sandstones and carbonates appear to be the lithologies most likely to sustain permeability at depth.

There is a question whether the higher temperatures within the target zone for stratigraphic geothermal reservoirs compared to petroleum reservoirs at the same depth may increase rock ductility and decrease permeability. Two examples of deep gas plays in the Rockies region suggest that for temperatures of up to 240°C this doesn't appear to be an issue with carbonate rerservoirs (Wilson et al., 2003; Figure 3b). High permeability Mississippian carbonates (often dolomitic) at hydrostatic pressure were encountered at depths of 5 – 7 km and temperatures of 210 - 240°C despite over-pressured formations at shallower depth. The hydrostatic condition implies pressure connection with the near surface, presumably because of the high lateral permeability within the carbonate formation, and a vertical connection in fault zones near the boundaries of the basins. There is a similar relationship between hydrostatic pressure and the Mississippian carbonate reservoir beneath the Paradox basin (Allis, 2014). The eastern Great Basin is also underlain by lower Paleozoic carbonates which appear to control inter-basin groundwater flow (Masbruch et al., 2012), and Allis (2014) has found that local hydrostatic conditions prevail everywhere. It is possible the inverse situation of over-pressures in prospective reservoirs may be an indicator that the prospective reservoir volume is limited and isolated from regional zones of high permeability by stratigraphy or faults.

The occurrence of laterally extensive, high (stratigraphic) permeability and hydrostatic pressure at depths of 3 to 7 km in the carbonate examples discussed above contrasts with the over-pressured fractures and the challenges associated with the hydraulic fracturing necessary to develop a viable EGS reservoir at 3 – 5 km depth in the Paralana and Habanero projects of South Australia (Bendall et al., 2014). The large reservoir volumes required for large-scale geothermal power favors reservoirs with laterally extensive, naturally high permeability andvery likely, pressures that are close to hydrostatic. Dolomites may be the favored lithology because they are stronger than limestones, and the dolomitization process creates porosity, which is the main reason they have become a reservoir target for oil and gas exploration in recent years (Davies and Smith, 2006).



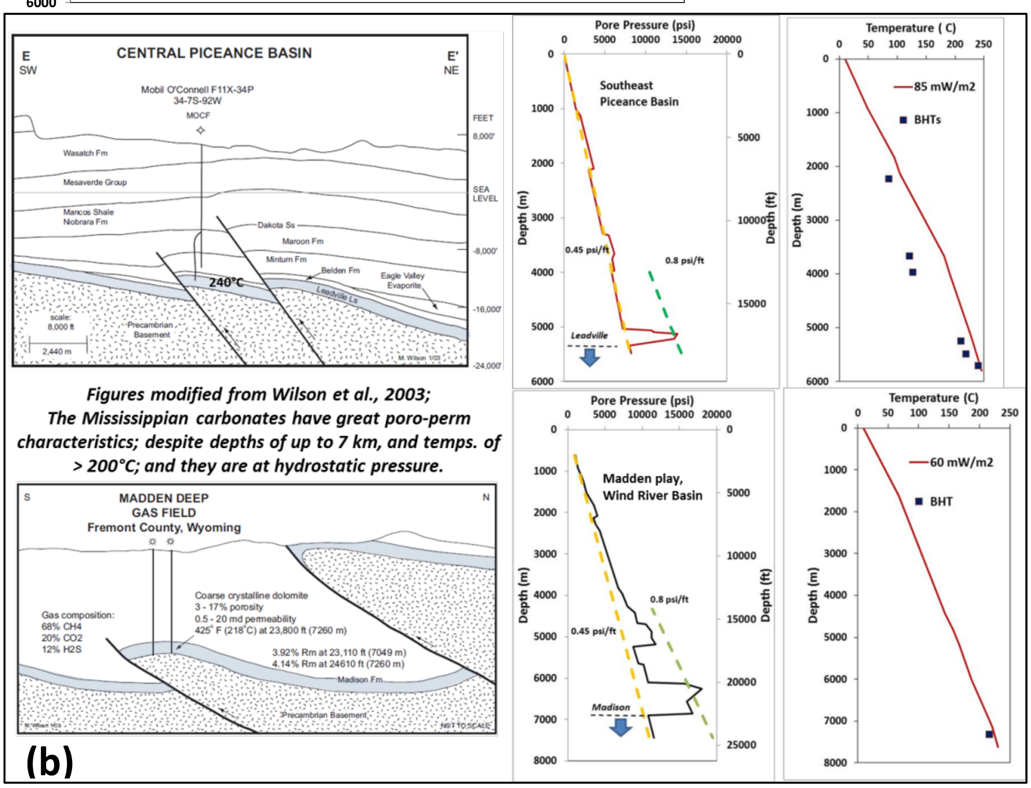


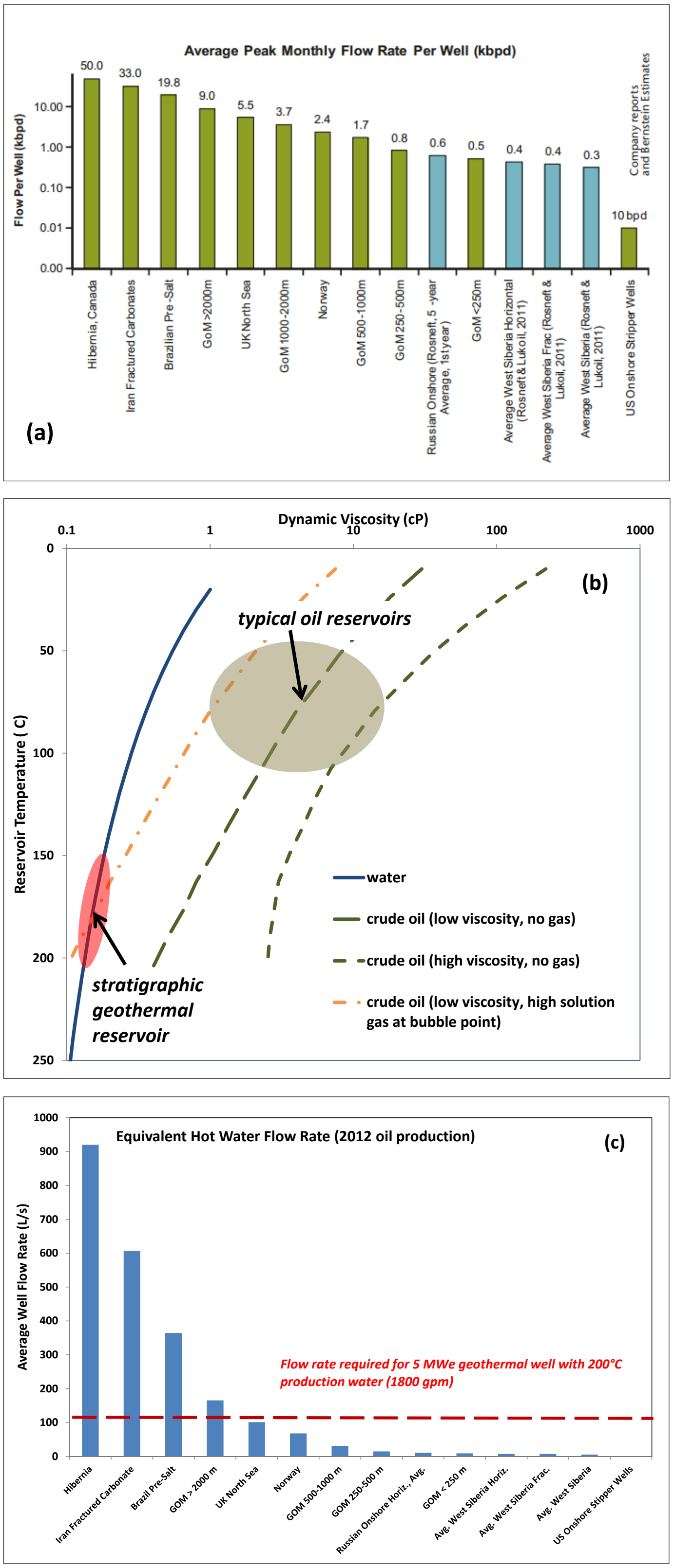
Figure 3a. Compilation of permeability measurements documented in oil exploration (Dept. of Energy Gas Information System - GASIS) and groundwater databases for the Great Basin and Rocky Mountain regions (Kirby, 2012), split by lithology. The ellipse highlights the measurements in the depth range of interest (3 - 4 km) for stratigraphic geothermal reservoirs.

Figure 3b. Two examples of pressure and temperature trends from deep basins in and adjacent to the Rocky Mountains region, where high permeability Mississippian carbonate (Leadville-Madison) is encountered between 5 – 7 km depth, and temperatures are between 210 and 240°C (modified from Wilson et al., 2003).

Production Well Flow Rates

Geothermal production wells require high flow rates, especially if the target reservoir is deep (3 – 4 km), and minimizing wellfield costs is essential for an economic project. Wells that are capable of generating 5 – 10 MWe need to have hot water flow rates of about 100 L/s, equivalent to about 300 tonnes/hour, 50,000 barrels/day (50 kbpd), or 1600 U.S. gallons per minute (gpm). While pumps can handle such flow rates if the permeability is sufficient, it is rare that oil production from a single well reaches the 50 kbpd level. Petroleum exploration experts are sometimes sceptical that such flow rates are reasonable. Jones, (2013) has summarized characteristic flow rates per oil well from around the world in 2011 and 2012, where they were reported (Figure 4a). Indeed, only wells in Hibernia field offshore from eastern Canada had flow rates of 50 kbpd. The uncontrolled flow rate after the blowout of the Macondo well in the Gulf of Mexico in 2010 has been assessed by diverse groups of experts at 50 – 70 kpd (McNutt et al., 2012).

Oil flow rates and hot water flow rates cannot be directly compared because of the effects of viscosity. Flow rates are inversely constrained by fluid viscosity, which is well-determined in the case of hot water, but can be highly variable in the case of oil. Oil viscosity varies with composition, temperature, dissolved gas (and bubble point) and pressure (Society of Petroleum Engineers, 2013). For the general comparison purposes here, the spread in oil viscosity due to several factors has been shown in Figure 4b together with the variation in water viscosity with temperature. Conservatively assuming that hot water and oil at typical reservoir conditions have a 10-fold viscosity difference allows the oil flow rate histogram in Figure 4a to be converted to the equivalent flow of hot water per well (Figure 4c; flow rates converted to liters/second). This shows that fields in several areas around the world have reservoir permeabilities sufficent to support the high flow rates needed for geothermal production wells (if their reservoir temperatures were high enough). Put another way, oil wells with sustained production rates of about 5 kbpd and typical oil fluid properties have reservoir conditions that would also sustain good geothermal wells if the temperature is 150 - 200°C.



The tight oil (and gas) fields presently being developed in the U.S. with horizontal drilling and extensive hydrofracturing typically have initial flow rates of about 1 kbpd, decreasing to a small fraction of this after 2 years (Hicks, 2013). The low permeability regimes being stimulated here for oil production are clearly not suitable for geothermal production wells.

Scale of Power Developments

The relatively deep target for stratigraphic reservoirs of 3 – 4 km, and potentially high well field costs requires compensating savings in other cost factors. Large developments (~100 MWe) allow economies of scale with factors such as the permitting, transmission line, and mobilization of drilling rigs. Drilling costs in the Bakken tight oil play (North Dakota) have been reduced by at least 20% because of the known, predictable geology and drilling conditions in the sedimentary environment, and other factors such as collocated wells on the same drill pad and "walkable" rigs (Hicks, 2013). That same predictability applies to stratigraphic geothermal reservoirs, so that once one or two confirmation wells have identified the thermal gradient, the permeability target, and the optimal drilling strategy and well-field design, grid-drilling is possible.

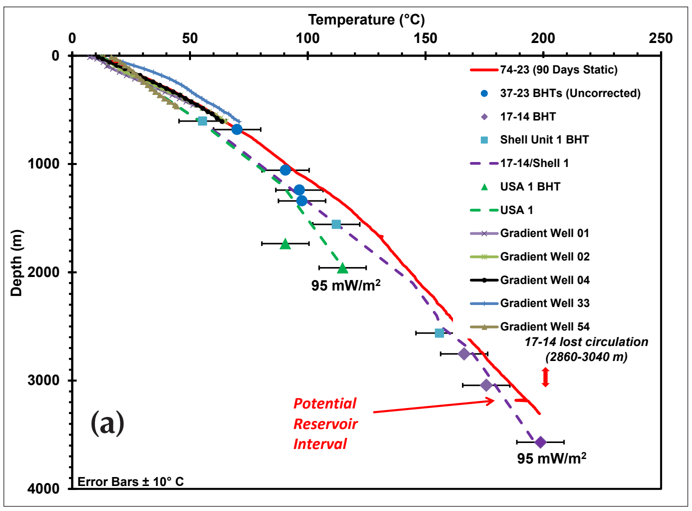
The relatively wide well-spacing for injectors and producers (500 – 700 m for reservoirs with 10 Darcy-m transmissivity and wells pumped at 2000 gpm), may mean modular developments of ~30 MWe are more cost-effective than one large, central power plant. Using the long-term power density of 3 MWe/km^2 (Deo et al., 2014), a 30 MWe development will have a well-field of about 10 km^2 (4 miles^2). Since many of the basins in the Great Basin are ~10^3 km^2 in area, large scale power developments are possible—if the reservoir characteristics can be proven over a 1 km^2 area, there is a very good chance the reservoir will have the same characteristics over 100 km^2.

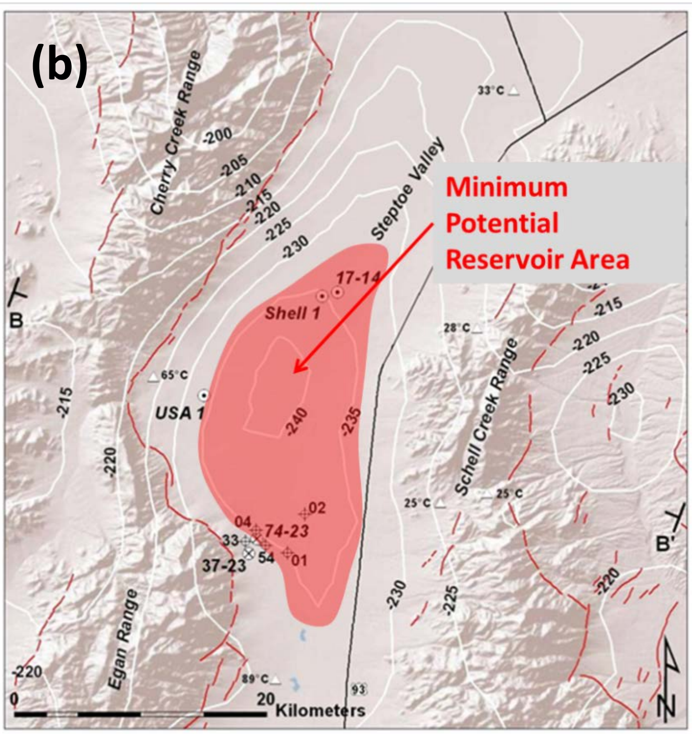
To illustrate this, we show an example from eastern Nevada where the several wildcat oil exploration wells in the early 1980s have proven that attractive temperatures and also good permeability exist in carbonate units at about 3 km depth (Figure 5; details in Allis at al., 2012). North Steptoe Valley is situated between the Cherry Creek and Schell Creek ranges. The valley (basin) has an 89°C spring near its southern end, and a 65°C spring adjacent to its western range-front. Shell Oil (Shell-1) and Placid Oil (well 17-14) drilled in the center of the valley, and confirmed 2 km of valley fill and predominantly Paleozoic carbonates and shale to at least 3566 m depth. The temperature between 3 and 3.5 km depth ranges between 170 and 200°C. Four carbonate units, the Guilmette Formation, Simonson Dolomite, Sevy Dolomite, and Ely Springs Dolomite, are known elsewhere to have characteristi-

Figure 4. (a) Compilation of available data on oil well production in fields around the world with publicly available data (Jones, 2013). (b) Trends in dynamic viscosity with fluid temperature for water and oil with varying composition and fluid characteristics (Society of Petroleum Enegineering, 2013). (c) Oil flow data from (a) converted to equivalent flow of 200°C water assuming the hot water has a viscosity one tenth that of oil. The red dashed line is the flow rate required for a 5 MWe well assuming 10% conversion efficiency, and a 75°C injection temperature. This shows the productivity of wells in the five oil regions with highest productivity would also support high flow-rate geothermal wells if the reservoir temperature was 200°C.

cally high permeability. These units represent a potential reservoir section more than 500 m thick. In addition, faults may enhance the permeability in this section of the Placid Oil well. About 20 km to the south, Hunt Energy Corp. conducted some temperature gradient drilling in the late 1970s and then drilled two geothermal exploration wells (Chovanec, 2003). The deepest well (74-23) had a temperature of 198°C at its total depth of 3308 m. The continuous temperature profile in this well is remarkably similar to the trend of corrected bottom hole temperatures (BHTs) in the two wells in the center of the valley to the north. Well 74-23 penetrated a quartz monzonite intrusion below about 1700 m depth, confirming the gravity anomalies suggesting the basin is slightly deeper extending at least 20 km farther north.

Based on the present information, the prospective area with attractive temperatures at about 3 km depth extends over at least 200 km^2. More detailed gravity is required to better define the base





of the surface fill, and some modern seismic reflection surveying is also required to image the lower-Paleozoic carbonate section (i.e., beneath the Chainman Shale) and faults such as the one suspected at 3200 m in well 17-14 (Figure 5c). Some oil industry seismic lines have been collected in this valley, but unfortunately the quality of the reflections from beneath the valley fill is poor (Schelling et al., 2013). However, based on the known potential reservoir section at 3 km depth in the middle of the valley, and the apparent uniformity of the thermal regime across the basin, even with a conservative power density of 3 MWe/km^2, half of the propective reservoir area in Figure 5 may support a power plant of several hundred MWe. NVEnergy has just completed a 500 kV transmission line with 600 – 800 MW capacity, linking a substation at Robinson Summit (just west of the Egan Range, Figure 5) and Las Vegas (NWEnergy, 2014), so transmission issues should not be a major problem.

Results similar to North Steptoe Valley are expected in many of the sub-basins identified so far by Moore and Allis (2013) as having a thermal regime that satisfies the target stratigraphic reservoir zone (shown in Figure 1). The ongoing evaluation of the thermal regime and stratigraphic, high-permeability, candidate reservoirs within the Great Basin is expected to reveal many more sub-basins with attractive development characteristics.

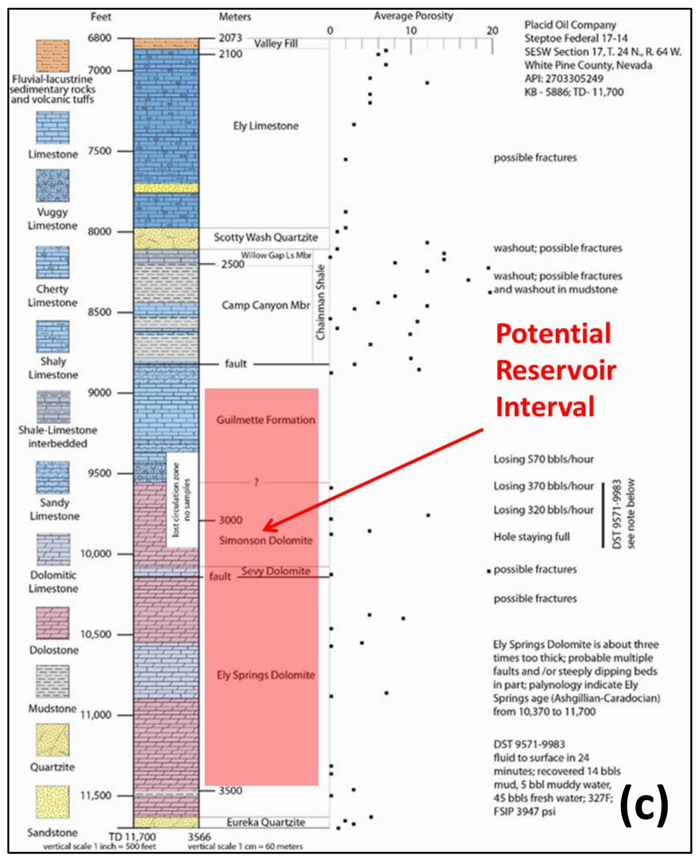


Figure 5. (a) Temperature-depth trends from wells in North Steptoe Valley, with the potential reservoir interval highlighted. (b) Location of wells drilled in North Steptoe Valley; well 17-14 close to the Shell-1 well was drilled by Placid Oil. (c) Detailed lithology, porosity, and drilling events for the Paleozoic section of the Placid 17-14 well. All three figures have been slightly modified from Allis et al., (2012), where more details can be found.

Conclusions

Abundant evidence from petroleum exploration shows that stratigraphic permeability capable of supporting high flow-rate geothermal wells can be found in many sedimentary basins. Although global geothermal experience with EGS projects and other deep drilling in volcanic or igneous host rocks suggest hydrothermal alteration may limit good permeability at high temperature and at depths of more than 3 km, lithologies such as clean carbonates and sandstones can sustain high permeability to at least 5 km depth. Examples from deep wells in two Rocky Mountain basins also show that carbonate reservoirs, possibly dolomitic, can preserve high permeability when the temperatures are 220 - 240°C and at more than 5 km depth. The inverse relationship between carbonate solubility and increasing temperature suggests carbonates may be a preferred reservoir target. The eastern Great Basin is underlain by a lower Paleozoic carbonate section that ranges up to 3 km in thickness and is known to have good permeability (Heilweil and Brooks, 2011). Large areas of the Great Basin have heat flows of more than 80 mW/m^2, providing numerous reservoir targets where temperatures will be 175 - 200°C at depths of 3 – 4 km, and good stratigraphic permeability is known or inferred. The large areas of these reservoirs (~ 10^2 to 10^3 km^2) can each support power plants of more 100 MWe.

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