PROCEEDINGS, Thirty-Eighth Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 11-13, 2013
SGP-TR-198

# Characterizing the Power Potential of Hot Stratigraphic Reservoirs in the Western U.S.

Rick Allis[1], Joseph N. Moore[2], Tom Anderson[2], Milind Deo[3], Stefan Kirby[1], Richard Roehner[3], Thomas Spencer[2]

[1] Utah Geological Survey, Salt Lake City, Utah
[2] Energy and Geoscience Institute, University of Utah, Salt Lake City, Utah
[3] Chemical Engineering Dept., University of Utah
e-mail: rickallis@utah.gov

## ABSTRACT

Stratigraphic reservoirs with high permeability and temperature at economically accessible depths are attractive for power generation because of their large areal extent (> 100 $km^2$) compared to the fault controlled hydrothermal reservoirs (< 10 $km^2$) found throughout much of the western U.S. A preliminary screening of the geothermal power potential of sedimentary basins in the U.S., assuming present day drilling costs, a levelized cost of electricity over 30 years of ≤ 10c/kWh, and realistic reservoir permeabilities, indicates that basins with heat flows of more than about 80 $mW/m^2$, reservoir temperatures of more than 175°C, and reservoir depths of less than 4 km are required. This puts the focus for future geothermal power generation on high heat flow regions of California (e.g., the Imperial Valley and regions adjacent to The Geysers), the Rio Grande rift system of New Mexico and Colorado (especially the Denver Basin), the Great Basin of the western U.S., and high heat flow parts of Hawaii and the Alaska volcanic arc.

By far the largest area of high heat flow is within the Great Basin. Here the highest, regionally extensive temperatures at depths of less than 4 km exist beneath the late Tertiary to Recent basins. Basins with more than 2 km of unconsolidated sediments are the most attractive because of the insulating effects of these sediments. The challenge is to locate the hottest basins with potential reservoirs within the underlying bedrock units. Not all basins of the Great Basin have high heat flow, and adequate permeability for geothermal power production may not exist beneath some high heat flow basins. The lower Paleozoic carbonate units beneath the eastern Great Basin are known to be locally very thick (up to 5 km), and commonly have high permeability. A review of permeability measurements at 3 – 5 km depth from petroleum and groundwater wells for the Great Basin and adjacent Rocky Mountains shows carbonates have the highest permeabilities (median value of 75 mDarcy), followed by siliclastic units (30 mDarcy). These values are sufficient for geothermal reservoirs. Intrusive and volcanic rocks have much lower overall permeabilities at depth and unless fractures are induced artificially, can be expected to be relatively poor candidate reservoir rocks. In contrast to many oil and gas producing basins in the U.S., there is no evidence of over-pressures at depths of 3 – 4 km within the eastern Great Basin. The two major challenges to development are the identification of the hottest basins and characterizing the permeability at economically drillable depths. The latter must include the roles of low and high angle faults and mineral dissolution in locally enhancing stratigraphically controlled fluid flow. Large-scale power production from these reservoirs may require the application of enhanced permeability techniques such as acid treatment of carbonate reservoirs and hydrofracturing. Reducing or minimizing the drilling costs by repetitive drilling in these basins to 3 – 4 km depth may be important for the economics, as is the possibility of solar augmentation of power generation.

## INTRODUCTION

Many geothermal reservoirs in the western U.S. occur on or near steeply dipping faults hosting hydrothermal upflow zones. The reservoirs are sub-vertical, and in the case of most developed fields in the Great Basin, the production wells are concentrated in relatively small areas (< 3 $km^2$), and power plants are typically < 50 MWe in capacity. Production is from 1 to 3 km depth. Most of the obvious upflow plumes have been explored and it is becoming increasingly difficult to find blind upflow zones (Blackwell et al., 2012). The purpose of this paper is to show that stratigraphic reservoirs represent an under-explored play concept with potential for 100 MWe-scale developments (Allis et al., 2011; 2012). In contrast to hydrothermal upflow zones, these systems are sub-horizontal with areas comparable to the area of the basin and are dominated by thermal conduction. Consequently, there is a much lower, predictable drilling risk compared to upflow zones. However, the conductive thermal regime also means that even in high heat flow basins (> 80 mW/m$^2$) suitable temperatures (>150°C) are deeper than in the hydrothermal upflows (i.e., reservoir depths at > 3 km).

An ongoing challenge developing enhanced geothermal systems (EGS) is the ability to create large-scale fracture networks linking production and injection wells, whereas in fault controlled hydrothermal systems the challenge is to locate relatively narrow zones of permeablility. In contrast, stratigraphic reservoirs have a natural permeability, which once confirmed with an exploration well, represents an easier drilling target for subsequent wells. Geothermal developments will be analogous to water flood techniques commonly utilized for secondary recovery in mature oil fields. The arid conditions over large areas of the western U.S., and other environmental considerations mean that future geothermal power developments will mostly use air-cooled binary plants with total water injection. Production and injection wells need to be judiciously spaced to optimize heat sweep. Allis et al. (2011) pointed out that high heat flow basins in the Great Basin may have temperatures at 3 – 4 km depth that are 50°C higher beneath the basins than beneath the adjacent bedrock ranges. We will show that this temperature increment is a major factor influencing a viable development.

The research described in this paper is the culmination of a large team funded largely by the Geothermal Technologies Program of the Department of Energy and described in a contract deliverable (Moore and Allis, 2013). The primary goal of Phase I of this project has been to determine if stratigraphic reservoirs can be developed at a levelized cost of electricity of not more than about 10c/kWh. Our results indicate they can be. A practical implication of this cost constraint is that the reservoir cannot be more than about 4 km in depth.

## NATIONAL PERSPECTIVE

The MIT report (Tester, 2006) screened the U.S. for near-term EGS prospects, and highlighted the following areas as having temperatures of >200°C at about 4 km depth: the Great Basin and adjacent Snake River Plain, the Oregon Cascades, the Southern Rocky Mountains, the Salton Sea (Imperial Valley), and the Geysers – Clear Lake area (Fig 1). Most of these areas contain basins with potential stratigraphic reservoirs. More recently Porro et al. (2012) evaluated 15 sedimentary basins for their geothermal potential by considering basin volume and temperature with increasing depth, and the available stored heat with depth. The Williston Basin was shown to have by far the greatest stored heat at temperatures of 100 – 120°C, but only the Great Basin was found to have temperatures of more than 150°C at less than 5 km depth. Porro et al. (2012) did not consider the thermal potential of very thick sequences of Paleozoic sediments beneath the Tertiary basin fill in the Great Basin.

Anderson (2012) recently completed a screening of sedimentary basins across the West and Midwest of the lower 48 states of the U.S. This study extended the thermal assessment of sedimentary basins of Porro et al., 2012, to include the Gulf Coast and Imperial Valley. The data available for each basin was reviewed and porosity-permeability-temperature relationships were assessed. Anderson (2012) considers prospective basins to require sedimentary formations with more than 10% porosity, at least 50 – 100 mD permeability, and temperatures of more than 125°C at depths of less than 4 km depth.

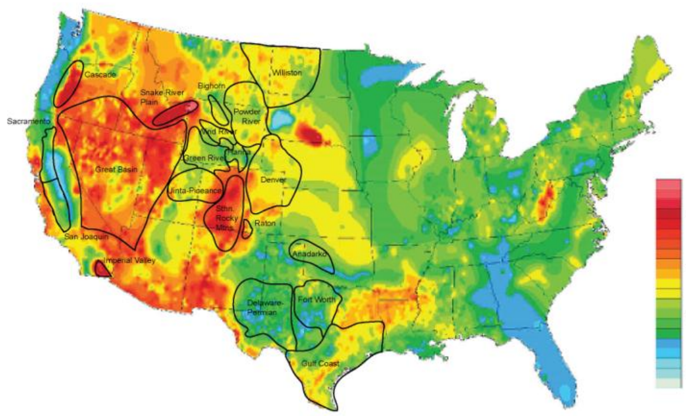



*Fig. 1. Heat flow map of the U.S. (Blackwell et al., 2011) overlain by outlines of major basins considered by Porro et al., (2012), and Anderson (2012). The areas labeled Great Basin, Snake River Plain, Cascades, and Imperial Valley were considered by MIT (2006) to be near-term EGS prospects with > 200°C at 4 km depth.*

Based on only the porosity and temperature constraints, eight basins remain for further consideration: Denver (CO), Fort Worth (TX), Great Basin (mostly NV and UT), Gulf Coast (TX and LA), Imperial Valley (CA), Raton (CO and NM), Sacramento (CA), and Williston (ND, SD and MT). However, when also considering permeability at less than 4 km depth, based on the available reservoir data, the Raton basin and the Williston were excluded. Anderson (2012) also noted that the target area in the Raton Basin was relatively small. In addition, the areal extent of the targets for the Fort Worth and the Sacramento Basins were considered limiting factors. The three strongest candidates meeting all the criteria were the Great Basin (actually consisting of many basins), the Gulf Coast, and the Imperial Valley, with the Denver Basin being ranked as mid-range potential and needing further evaluation. Crowell et al. (2012) have subsequently shown that temperatures deep within the Denver Basin may be significantly higher than Porro et al. (2012) assumed, with temperatures of 160°C at 3 km depth, and 210°C at 4 km depth.

## GREAT BASIN THERMAL REGIME

When more stringent reservoir temperature constraints are considered, the choice for prospective development areas becomes more limited, as highlighted in Figure 2. If the economic lower limit for power generation is about 150°C in reservoirs at less than 4 km depth, only the Great Basin, Imperial Valley and the Denver Basin remain from the original 17 basins considered by Porro et al (2012) and Anderson (2012).

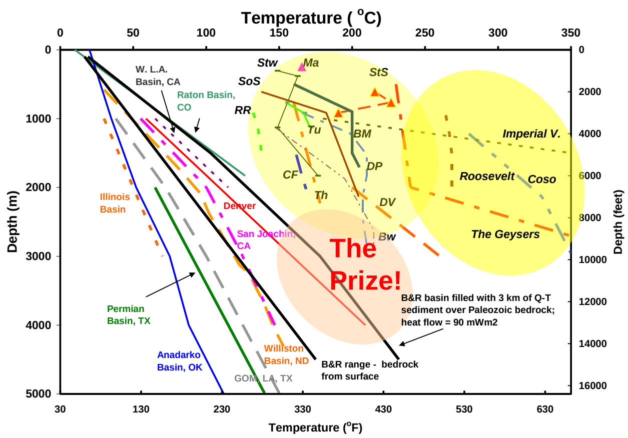



*Fig. 2. Selected temperature profiles from hydrothermal systems in the western U.S. (bright yellow – high temperature systems; light yellow – low temperature systems). Also shown are profiles from several large sedimentary basins. Most U.S. geothermal developments are at temperatures of more than 150°C, and less than about 3 km depth. Two geotherms representing high heat flow (90 mW/m$^2$) beneath deep basins and beneath ranges in the Great Basin are plotted. Note that temperatures at 3 – 5 km depth are about 50°C hotter beneath the basin than at the same depth beneath the range. "The Prize" is the area of potential stratigraphic reservoirs beneath high-heat flow basins that should be a target for future geothermal development (Allis et al., 2012). Key: L.A., Los Angeles Basin; GOM, Gulf of Mexico onshore (Louisiana) and offshore (TX); 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, Tu, Tuscarora; UT; DV, Dixie Valley, NV; Bw, Beowawe, NV; RR, Raft River, ID. The location of most of these systems is shown in Fig. 3.*

Figure 2 subdivides the temperature-depth data into three categories: high temperature hydrothermal systems with temperatures above 250°C, moderate temperature hydrothermal systems with temperatures between 150 and 200°C, and sedimentary basins with conductive thermal gradients at all depths. Although the Great Basin has many hydrothermal systems and areas where convective flow has disturbed the thermal regime, it also has large areas characterized by thermal conduction. The high heat flow areas of the Great Basin typically have heat flows of 80 – 100 mW/m$^2$ (Lachenbruch and Sass, 1977, Blackwell, 1983, Blackwell et al., 1991, Tester et al., 2006; Fig. 3).

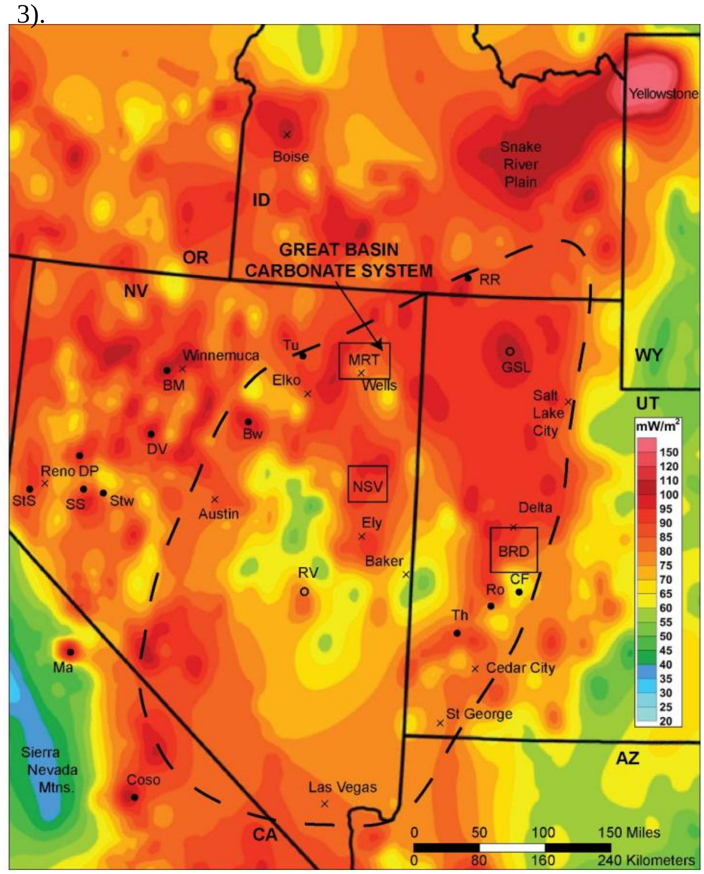
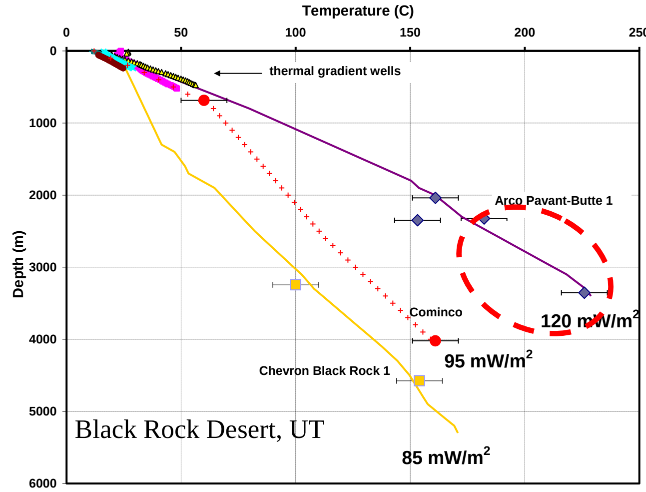



*Fig. 3. Heat flow map centered on the Great Basin of the western U.S. (Blackwell et al., 2011), overlain by developed geothermal systems (black dots, with labels from caption in Fig. 2). The eastern Great Basin contains a large thickness of Paleozoic carbonates (labeled as "Great Basin Carbonate System") which are known to have high permeability (Heilweil and Brooks, 2011; Masbruch et al., 2012). The three boxes enclose parts of the Black Rock Desert (BRD), North Steptoe Valley (NSV), and Marys River-Toano Basin (MRT), which are three basins known to have high temperatures in the Paleozoic sediments beneath Tertiary to Recent sedimentary fill. See Figure 2 for other abbreviations.*

Because unconsolidated sediments have relatively low thermal conductivities compared to consolidated sediments (bedrock), the temperatures below about 2 km depth in basins of the Great Basin are ~50°C higher than beneath the adjacent ranges where bedrock crops out. Therefore, if particular sedimentary formations are known to be characteristically permeable, these formations represent potential geothermal reservoirs if hot enough, and the best chances of maximizing temperature should be beneath the basins. Figure 2 shows temperatures of around 200°C should exist at 3 – 4 km depth in high heat-flow basins (~ 90 mW/m$^2$) with 2 – 3 km of overlying, unconsolidated sediments. The region highlighted as "The Prize" where temperatures are 150 – 200°C is at slightly greater depth than the numerous developed hydrothermal reservoirs in the Great Basin. Comparison of generalized heat flow regimes in Figures 1 and 3 suggests that an area of at least 1000 x 500 km$^2$ of the Great Basin should be highly prospective for high heat-flow basins and stratigraphic reservoirs.

Allis et al. (2011, 2012) and Gwynn et al. (2013) have shown that in several basins in the eastern Great Basin, temperatures of about 200°C have been measured in oil exploration wells (Figure 4 shows two examples; another example is in Mary's River Basin in northeast Nevada, where temperatures reach 200°C at about 4 km depth). However there has been no geothermal development in these basins. Detailed analysis of the structure and stratigraphy from the well logs, seismic reflection interpretation and gravity trends shows the high temperature wells are centrally located in lower Paleozoic carbonate units beneath 3 km of upper Cenozoic sedimentary fill. In the case of the high temperature well in Black Rock Desert (Arco Pavant Butte 1), it is unclear how permeable the limited section (50 m) of Cambrian carbonate was, although elsewhere in the basin these carbonate units are known to be permeable. In North Steptoe Valley, the Placid 17-14 well had a major loss zone between 2.9 and 3.1 km depth coinciding with carbonate formations known for their high permeability (Allis et al., 2012; Figure 4). Both basins have areas of the order of hundreds of km$^2$. Allis et al. (2012) concluded that the geothermal power potential of these stratigraphic reservoirs could be substantial. They also reasoned that there are likely many other basins in the Great Basin that may have similar characteristics. Masbruch et al. (2012) reviewed the hydrological characteristics of the lower Paleozoic carbonate system beneath the eastern Great Basin, and screened their stratigraphic GIS information layers for basin-fill of more than 2 km depth and heat flows of more than 80 mW/m$^2$ as shown in Blackwell et al (2011; Figure 3). They highlighted numerous locations where basin-centered geothermal reservoir may exist.



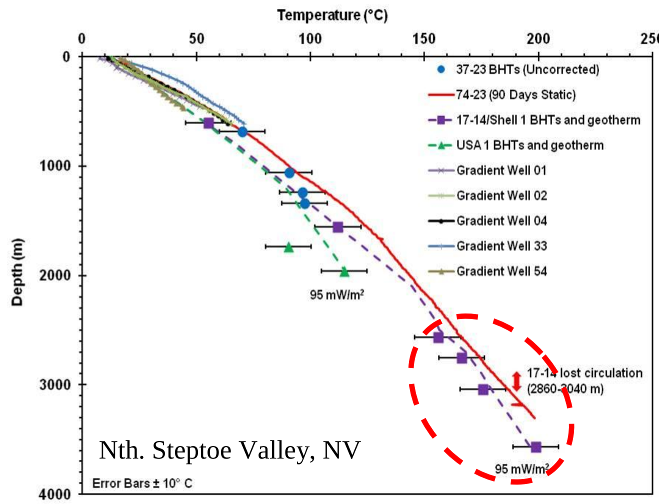




*Fig. 4. Temperature-depth trends from two basins in the eastern Great Basin where temperatures of about 200°C exist between 3 – 4 km depth based on measurements in oil exploration wells (now abandoned), and lower Paleozoic carbonate units known to be permeable exist at these depths. The temperature gradients in shallow wells are consistent with the deep temperatures. The locations of these basins are shown on Fig. 3.*

## PERMEABILITY

Mass flow rates from good geothermal production wells (~ 80-100 kg/s) are typically larger than for good oil wells (5,000 – 10,000 barrels/day or 16 – 32 kg/s). Successful geothermal reservoirs therefore require excellent permeability characteristics. In the reservoir modeling carried out for this project, it was found that reservoir transmissivities (permeability-thickness product) in the range of 1 – 10 Darcy-meters gave reasonable thermal and pressure responses on a timescale of several decades, depending on how the permeability was distributed. This is at the low end of transmissivities considered by Sanyal and Butler (2009) when modeling the non convective geothermal resources in the Gulf Coast. However our analysis of characteristic permeability distributions suggests large thicknesses (> 300 m) of relatively high permeability (> 100 millidarcy, mD), are unrealistic in many basins, especially the Great Basin.

Anderson (2012) has reviewed the porosity-permeability data for many basins in the western U.S. as part of screening basins for their geothermal reservoir potential. Figure 5a is a compilation of the data for possible reservoirs in the 17 basins he considered (locations in Figure 1). The averages are superimposed on the global trends compiled by Ehrenberg and Nadeau (2005) for carbonates and sandstones. There is a large scatter in the data, but the pattern suggests permeabilities of ~ 100 mD and porosities of ~ 20% are common in formations with reservoir characteristics.

Kirby (2012) reviewed oil exploration and groundwater databases for the Great Basin and adjacent basins in the Rocky Mountains to characterize permeability as a function of depth and dominant lithology. A compilation of all the data is shown in Figure 5b. All lithologies show a significant decline in permeability between the surface and about 1 km depth. However, at greater depth the trend for both siliciclastics and carbonates is remarkably constant. Between 3 – 5 km depth, the average permeability for carbonates is 75 mD and that for siliciclastic rocks is 30 mD. In contrast, the permeability of basin fill and igneous lithologies (volcanic and intrusive rocks) decreases with increasing depth to about 1 mD at 2.5 km, the maximum depth for which there is data. Kirby (2012) has also shown that the permeability distribution between 3 – 5 km depth for carbonates and siliciclastic rocks remains log-normal. This could be a useful relationship when simulating the response of deep reservoirs to long-term production.

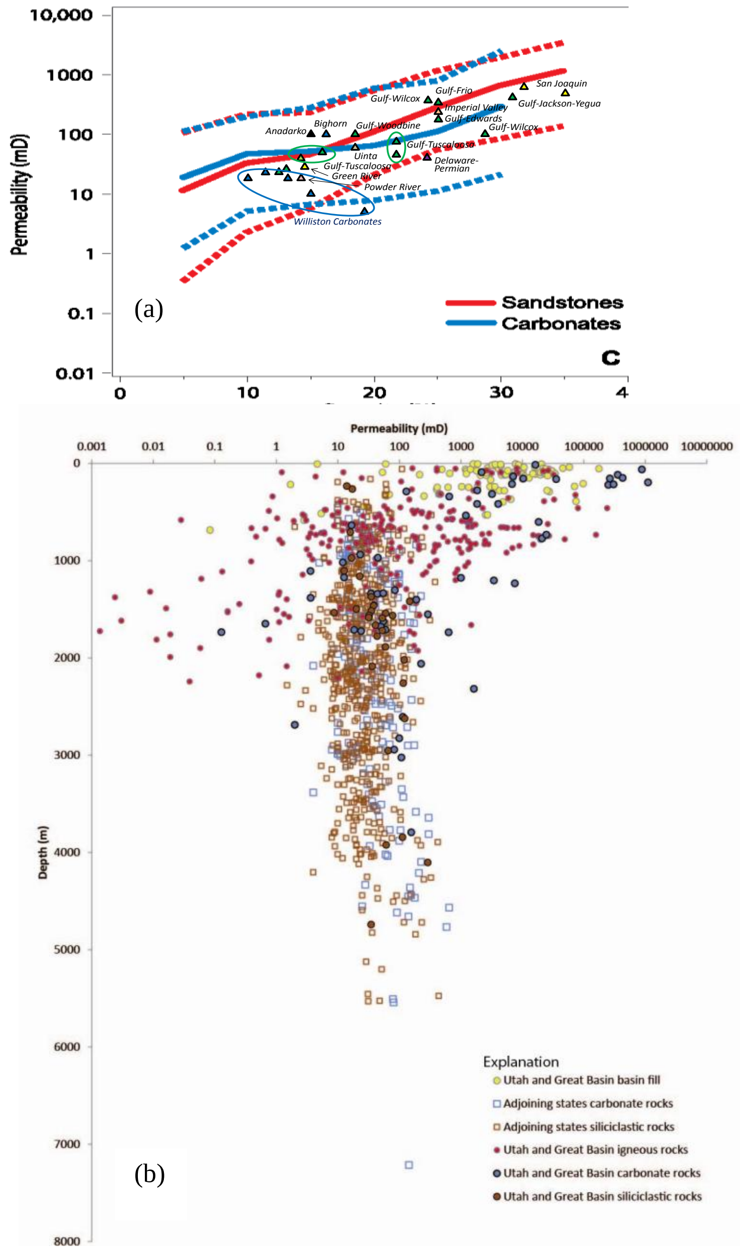



*Fig. 5a. Compilation by Anderson (2012) of porosity-permeability relationships from potential reservoir units in basins of the western U.S., superimposed on global trends for carbonates and sandstones derived by Ehrenberg and Nadeau, (2005); dashed lines are 90% limits; 5b, compilation of permeability measurements in oil exploration and groundwater databases (Kirby, 2012).*

## RESERVOIR PRESSURE

In many sedimentary basins pressures often exceed hydrostatic at depths of more than 3 km, especially when thick shale units are present. Although the Great Basin is not noted for its oil production, there has been widespread exploration drilling and several producing fields exist (e.g., Railroad Valley, Figure 3). Well logs and drill-stem test (DST) data have been reviewed as part of this project to investigate whether excess pore pressure is a risk factor with deep geothermal drilling (Figure 6; Allis in prep.). Procedures for screening the DST data followed Allis et al. (2008). There can be large uncertainties when screening DST data, especially with tests in low permeability formations, when shut-in pressures after flow tests are still far from equilibrium (i.e., too low). So far, all DST data are consistent with hydrostatic pressures from near the ground surface, even in wells as deep as 5 km. The most obvious reasons for this are the normal faulting regime, the relatively narrow width of the basins, and the outcrop of the basin-centered bedrock sequences in adjacent ranges.

The lack of over-pressure in the Great Basin means the risks of deep drilling are low compared to oil and gas basins elsewhere. This conclusion matches a similar comment in the GETEM handbook (2006;

Table 5.1) and its implications for drilling costs. There is also a much lower risk of unexpected high temperature fluid because the thermal regime in the central basin fill is dominated by thermal conduction.

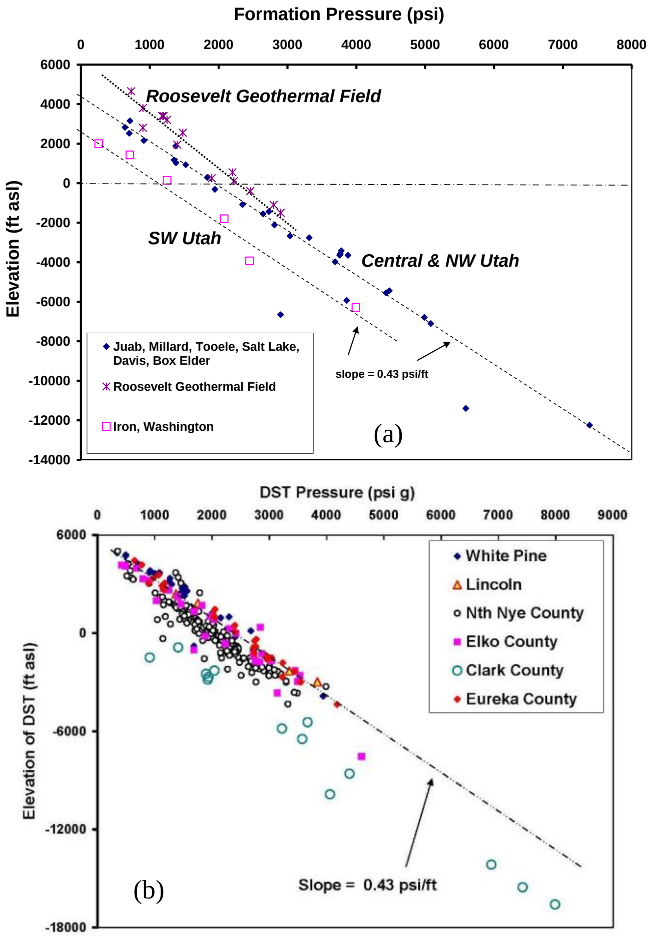



*Fig. 6. Pressure trends with depth inferred largely from oil exploration wells and a few geothermal wells in eastern Nevada (a) and western Utah (b; Allis, in prep.). Data are grouped by county, and formation pressures are derived from drill stem test (DST) results. All the data are consistent with a hydrostatic pressure gradient. The steeper gradient at Roosevelt Hot Springs Geothermal Field is also consistent with hydrostatic conditions.*

## RESERVOIR MODELING

Reservoir models were constructed to simulate the rate of heat extraction from sub-horizontal reservoirs consisting of a realistic range of permeabilities, layer thicknesses, and thermal regimes representative of the stratigraphic reservoirs being considered. Both environmental considerations and reservoir management constraints designed to limit pressure declines due to production require all produced water to be reinjected. Injection wells are open to the same stratigraphic units as the production wells, and the heat sweep process is analogous to water flood techniques commonly used for secondary oil recovery. Modeling was undertaken using the STARS Advanced Process and Thermal Reservoir Simulator, Version 2010. The five reservoir models that were simulated are summarized below. More detailed discussion of the results can be found in Deo et al. (2013). Each model consists of a reservoir-seal sequence as described below:

1. The Sandwich (base case) reservoir model has an average reservoir temperature of 200$^{o}$C at 3 km depth. The reservoir consists of four 25 m thick layers with a permeability of 100 mD and an overall transmissivity of 10 D-m. The seal layers between the high permeability layers have various thicknesses and a permeability of 1 mD (Tables 1, 2, and Figure 1). The model has 500 m of low permeability (1 mD) rock above and below the reservoir sequence, and a constant temperature is assumed at the upper and lower surface of the model to simulate the initial, thermally conductive regime. The initial pressure is assumed to be hydrostatic, with a pressure of 300 bar at 3 km depth.
2. The Single Layer reservoir model has the same general temperatures and transmissivity as the sandwich reservoir, but with no seal layers separating reservoir layers.
3. The Low Temperature model is the same as the Sandwich model, but with the average reservoir temperature being only 150$^{o}$C at 3 km depth.
4. The Low Permeability model is the same as the Sandwich model, but with reservoir layers having a permeability of 33 mD, and a total reservoir transmissivity of 3 D-m).
5. The Short Circuit model has one reservoir layer with a high permeability (300 mD), while the other three have permeabilities similar to the Low Permeability model layer. The overall reservoir transmissivity is the same as in the Sandwich model.

All models utilized a common five spot pattern with a 500 m well spacing as shown in Figure 7. This well spacing was chosen, after some preliminary modeling, to ensure large changes in temperature would be seen on a time scale of the economic life of a power plant (~30 years). The design flow rate in the production and injection wells was set at 1000 gallons per minute (63 liters/second), about half the maximum rate normally achievable using geothermal pumps. A critical assumption for all models is that production wells were pumped at a constant rate, and all produced water was injected at 75$^{o}$C after being cooled in a power plant. The relationship between the initial conditions for the modeling and the assumed pressure and temperature conditions for a hypothetical high heat flow basin are shown in Figure 7. The change in temperature gradient at the top of the model represents the increase in thermal

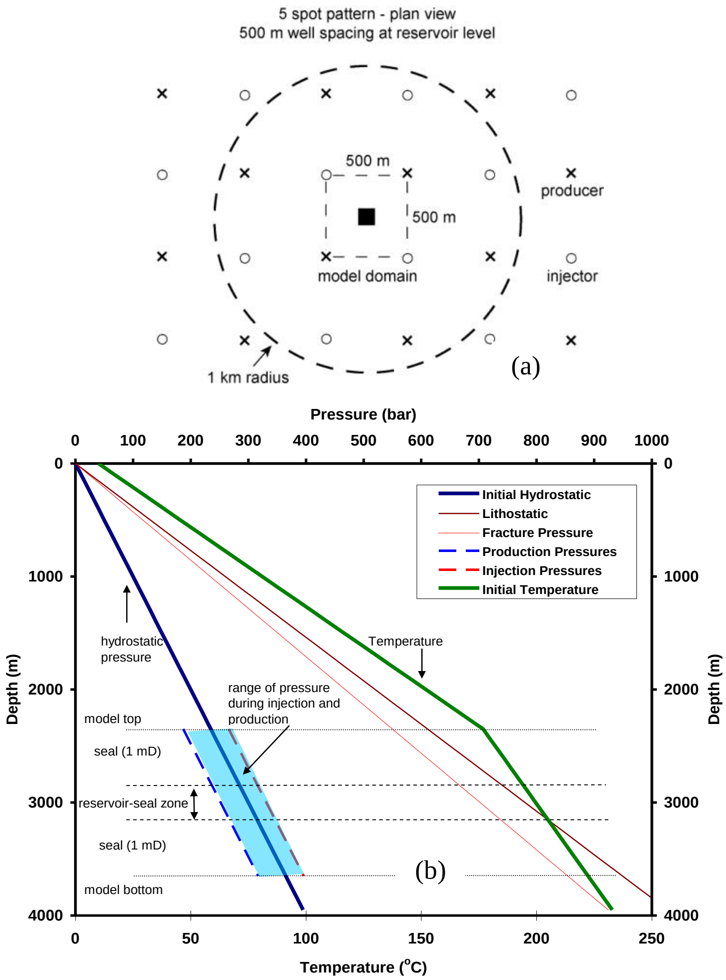



*Fig. 7: (a) well spacing used for the modeling. This spacing has two producers and two injectors per square kilometer, or about 9 wells per square mile. The model domain has two quarter producers and two quarter injectors on each corner. The 5-spot pattern has each producer surrounded by 4 injectors, and each injector surrounded by 5 producers. (b): Relationship of model assumptions to the temperature and pressure boundary conditions. The five models consider various permeability distributions within the reservoir-seal zone. The low temperature model has an initial temperature profile scaled so that it passes through 150°C at 3000 m.*

conductivity between the overlying sedimentary cover and the underlying bedrock hosted reservoir. This thermal regime is consistent with that in high heat flow sedimentary basins in the western U.S. as discussed above. Also shown in Figure 7 is the maximum range of pressures that were calculated from the models during production and injection. These pressure changes are small compared to a lithostatic pressure gradient and an inferred fracture gradient 90% of lithostatic.

The most obvious differences in the response of each model to production and injection are shown in the temperature changes after 30 years (Figure 8). Temperatures of less than 100°C have broken through in both the Single Layer model and the high permeability layer of the Short Circuit model within 30 years. Although the Sandwich, Single Layer, and Short Circuit models have the same total reservoir transmissivity (10 D-m), large differences in the extent and amplitude of cooling are apparent. These differences are highlighted by plotting the wellhead production temperature with time (Figure 9). Surprisingly, the best thermal performance comes from the Low Permeability model. The main reason for this is there is less permeability contrast between the reservoir units and the seal units (33:1), so a greater proportion of heat is being swept from the adjacent seal units on a time scale of decades. The pumped production wells are still producing at the same flow rate as in the other models, but the lower total transmissivity causes a greater lateral pressure gradient between the injection and production wells (about 60 bars compared to about 30 bars with the other models). In contrast, the seal units above and below the Single Layer model contribute little to the heat sweep process. The most rapid thermal decline occurs in the high permeability unit (300 mD) of the Short Circuit model, with a decrease in production wellhead temperature from 200 to about 150°C within 10 years. However at longer times, this model performs substantially better than the Single Layer model, and at 50 years, the wellhead temperature is not far below that for the Sandwich model.

The electric power output with time per unit area of the reservoir (i.e., basin) is also shown in Figure 9. This parameter is sometimes called the reservoir power density (Grant and Bixley, 2011). For all four 200°C models, the average power density over 30 years ranges between 4 – 9 MWe/km$^2$, and for the Low Temperature model it is 3 MWe/km$^2$. A basin with a 200°C stratigraphic reservoir extending over an area of ~ 100 km$^2$ conservatively has a power potential of 500 MWe.

In future phases of this work modeling will focus on optimizing the heat sweep and power output by varying well configurations, pump rates, and reservoir permeability characteristics.

## ECONOMIC MODELING

The Geothermal Electric Technologies Evaluation Model (GETEM, 2006) links the characteristics of geothermal resources to the estimated cost of power (LCOE, or levelized cost of electricity in c/kWh for the economic life of a development). It includes

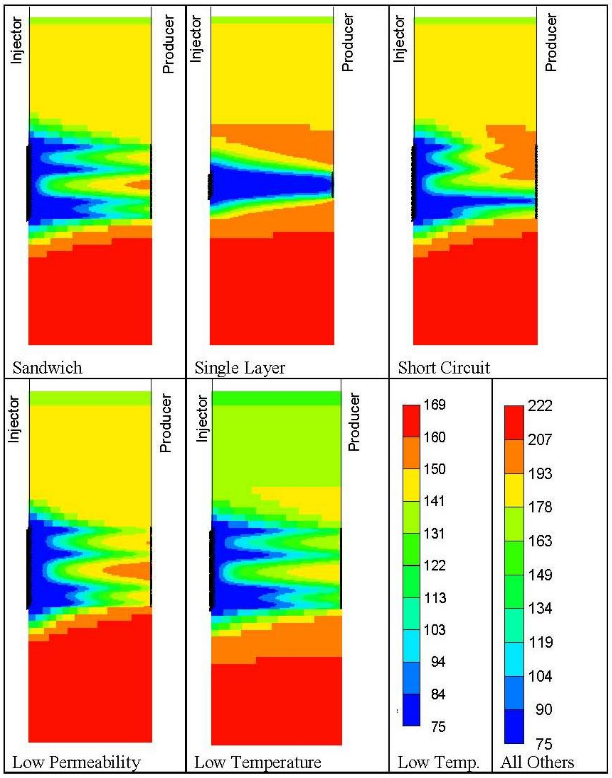



*Fig. 8. Cross-sections of temperature (°C) after 30 years of production and injection for all 5 models.*

engineering cost estimates such as operating and maintenance, reservoir performance estimates based on user specifications, the capital costs of exploration and investigation drilling, and plant costs. It also includes assumptions about depreciation and inflation impacts (Entingh and Mines, 2006). The model used here was updated and modified by V. Gowda at the Energy & Geoscience Institute in 2010. One of the critical cost components of the development of the deep, stratigraphic reservoirs being considered here is drilling. GETEM assumptions for the cost of drilling with increasing depth (Figure 10) were compared to recent estimates supplied by Bill Rickard of the Geothermal Resources Group (2011, pers. comm.) and found to be similar. The GETEM drilling cost trend has therefore been used for this study. Also shown on Figure 10 are drilling cost curves which are ± 20% compared to the standard curve. These trends imply that a production well that is 3 km deep costs \$5 ± 1 million. Drilling costs can be highly variable, so the 20% cost variable allows consideration of possible savings when drilling numerous identical wells into known conditions of 2 – 3 km of unconsolidated sediments overlying the bedrock reservoir section. The model incorporates drilling costs at the wildcat exploration stage (20% success rate), and resource confirmation stage (120% normal drilling costs) to allow for the costs of well testing and reservoir analysis (GETEM, 2006).

The modeling assumes a 100 MWe plant capacity, and pumps for production and injection wells. To

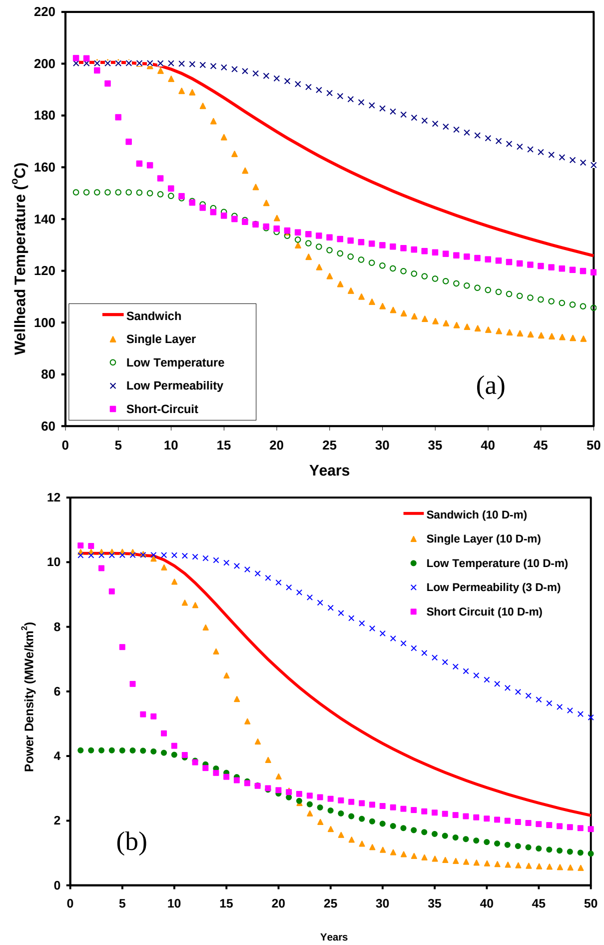



*Fig. 9. (a): Trends in production wellhead temperature with time. The Low Permeability model provides the most sustainable heat output. The most rapid thermal decline occurs in the Short Circuit model, although long-term, that model performs better than the Single Layer model. (b): Trends in power density with time, a measure of the efficiency of the heat sweep process of injected water within the reservoir-seal zone between injection and production wells.*

ensure the injection fluid is dispersed as uniformly as possible across the reservoir, the injector/producer well ratio was set to 1 in all models. The issue of varying well productivity (i.e. reservoir permeability) is handled by assuming the pump rates of the wells range between 500 and 2000 gallons per minute (31 – 127 L/s), and the pump rate is constant with time for a given scenario. The upper pump rate is representative of the maximum rate feasible with today's technology. The lower the pump rate requires more production wells for a power plant of fixed capacity, and therefore a higher the LCOE for the project.

In order to generate the various trends in LCOE for varying constraints such as pump flow rate, rate of temperature decline, wellhead temperature, well depth, and drilling costs, GETEM is coupled with @Risk allowing Monte Carlo simulations. Between

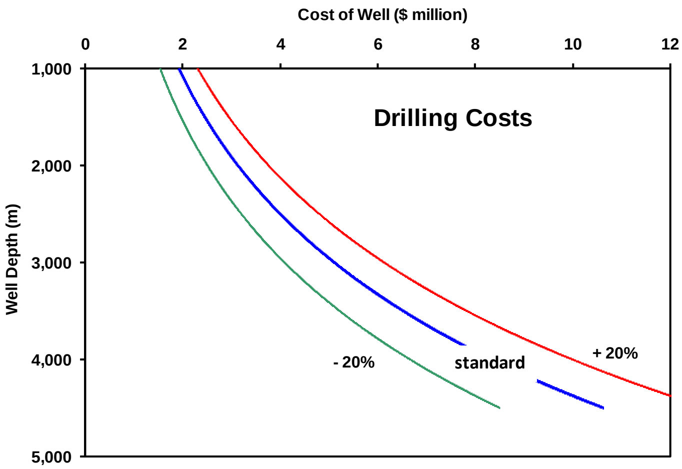



*Fig. 10. Drilling cost curves used in the GETEM modeling.*

5,000 and 10,000 simulations were run for each scenario. Results were then filtered to find the combinations of well depth and reservoir temperature that produce the required trends of LCOE (constrained to less than ± 0.2 c/kWh). All results are plotted on temperature-depth graphs to allow easy comparison with likely geotherms (temperature trends with constant heat flow) beneath the high heat-flow basins. The primary conclusion of this modeling was the recognition that "the prize" zone in Figure 2 is slightly deeper than the geothermal industry is used to. Therefore we needed to identify the key factors influencing the LCOE for these depths and temperatures.

Results of the economic modeling are shown in Figure 11. The effect of the increasing drilling cost with depth causes the constant LCOE trends to curve towards increasing reservoir temperature as improved economics of power generation offset the increased costs of drilling a deeper reservoir. If the reservoir is at 3 km depth and is able to be pumped at 2000 gpm, with a long term temperature decline rate of 1%/year, the LCOE decreases from 20 c/kWh with an initial reservoir temperature of 136°C, to 15 c/kWh at 150°C, and 10 c/kWh with an initial temperature of 184°C. The effects of pump rate and temperature decline rate are also shown in Figure 11 for a target LCOE based on power prices of 10 c/kWh (no production subsidy included). Given the typical Great Basin thermal regime of 80 – 100 mW/m$^2$, pump rates need to be at least 1000 gpm, and the reservoir temperature decline rate needs to be less than 1%/year. The effect of ± 20% on the standard drilling cost curve (Figure 10) shifts the 10 c/kWh lines by about ± 10°C. Increasing uncertainties in the drilling costs with depths greater than 3 km require caution when interpreting the almost parallel LCOE trends and in determining the geothermal gradient.
Being realistic about reservoir characteristics, we suggest the reservoir temperature needs to be at least 175°C at 3 – 4 km depth for the LCOE to be about 10 c/kWh. Comparison of several 10c/kWh LCOE trends with the thermal regime beneath the three basins in the eastern Great Basin shows them to be highly prospective (Figure 12).

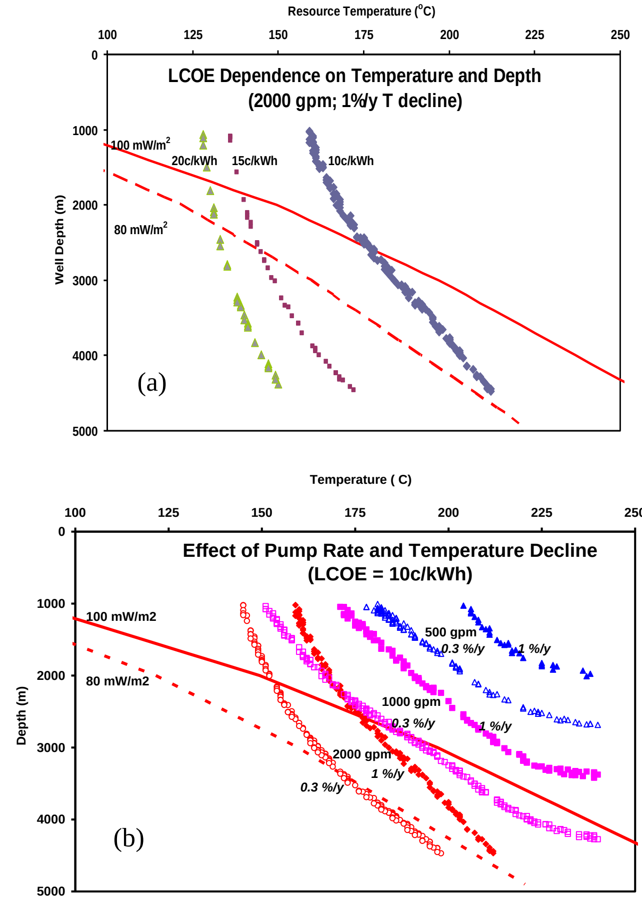



*Fig. 11. (a) Example of the LCOE trends with reservoir depth for a 100 MWe binary plant with wells pumped at 2000 gpm, and a production well temperature decline rate of 1 %/year. (b): LCOE trends of 10 c/kWh with reservoir depth for varying pump rates and reservoir decline rates with time. Both graphs show basin geotherms for 80 and 100 mW/m$^2$ (3 km of sedimentary fill on bedrock).*

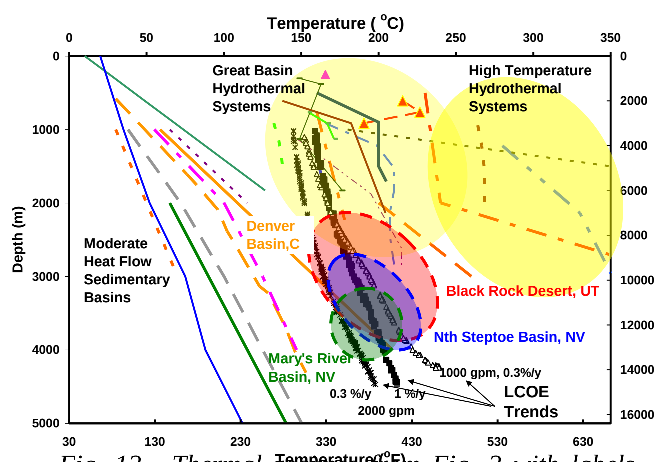



*Fig. 12. Thermal regimes from Fig. 2 with labels removed, and three 10 c/kWh LCOE trends from Fig. 11. The deep thermal regime from three basins in the Eastern Great Basin and the Denver Basin are highlighted.*

## CONCLUSIONS

***1.*** High heat flow basins have the potential to yield 100 MWe-scale geothermal power plants.

***2.*** Basins which have heat flows of more than 80 $mW/m^2$, and unconsolidated sediment fill of at least 2 km, should have temperatures of more than 175°C at less than 4 km depth.

***3.*** Such basins have reservoirs that could be ~ 100 $km^2$ in area, and are near-horizontal, in contrast to the relatively small area, near-vertical, fault-hosted geothermal reservoirs that are the usual target in traditional hydrothermal systems

***4.*** The reservoirs are stratigraphic units with natural permeability in bedrock units beneath the basin fill. Data from petroleum exploration wells and groundwater wells indicate that the required permeabilities of 10 – 100 millidarcies are not uncommon at depths of 3 – 5 km. In some basins reservoir permeability may be enhanced by faulting.

***5.*** Pressures of deep wells in the Great Basin are hydrostatic and show no evidence of overpressures. This has positive implications for drilling costs.

***6.*** Initial reservoir modeling indicates power densities of more than 3 $MWe/km^2$ are possible.

***7.*** Initial economic modeling indicates that levelized costs of electricity of 10c/kWh or less are feasible using pumped wells at 1000 – 2000 gpm, with the rate of production temperature decline with time being an important factor determining the cost.

***8.*** Technologies being developed for engineered geothermal systems (EGS) will be useful for optimizing and enhancing the permeability of stratigraphic reservoirs.

***9.*** The additional geothermal power potential from these basin-centered resources is estimated to be at least a GWe based on a preliminary screening of the Great Basin of the Western U.S.

***10.*** Ongoing research on high heat-flow basins in the Western U.S. is expected to yield 10 – 20 prospects suitable for exploration drilling and power development.

## ACKNOWLEDGMENTS

This paper is a shortened version of the Executive Summary from the Contract Deliverable for Phase I of Project "Novel Geothermal Development of Sedimentary Basins in the United States," Moore, J.N. and Allis, R.G. (editors; submitted 1/2013). The project was partially funded by the Geothermal Technologies Program of the U.S. Dept. of Energy (Award DE-EE0005128). We than Jay Hill, (Utah Geological Survey) for drafting some of the figures.

## REFERENCES

Allis R.G., Chidsey, T.C., Morgan, C.D., Heuscher, S., and Macdonald, A. 2008. The Mississippian-Leadville limestone exploration play, Utah and Colorado – exploration techniques and studies for Independents. Semi-annual Technical Progress Report October 1, 2007 – March 31 2008, Submitted to Department of Energy National Energy Technology Laboratory, July 2008, pp. 38.

Allis, R., Moore, J., Blackett, R., Gwynn, M., Kirby, S., and Sprinkel, D. S., 2011. The potential for basin-centered geothermal resources in the GreatBasin. Transactions, Geothermal Resources Council, 35, 683-688.

Allis, R., Blackett, R., Gwynn, M., Hardwick, C., Moore, J.N., Morgan, C., Schelling, D., and Sprinkel, D. 2012. Stratigraphic reservoirs in the Great Basin – the bridge to Enhanced Geothermal Systems in the U.S. Transactions, Geothermal Resources Council, 36, 351-357.

Anderson, T.C. 2012. Review of permeability characteristics in drilled, sediment-hosted geothermal systems. Report submitted as part of DE-EE5128 "Novel Geothermal Development of Deep Sedimentary Systems in the United States," Energy and Geoscience Institute, 66.

Blackwell, D.D. 1983. Heat flow in the northern Basin and Range province. In: The Role of Heat in the Development of Energy and Mineral Resources in the Northern Basin and Range Province. Geothermal Resources Council Special Report, vol. 13, 81–92.

Blackwell, D.D., Steele, J.L., Carter, L.S., 1991. Heat-flow patterns of the North American continent: a discussion of the Geothermal Map of North America. In: Slemmons, D.B., Engdahl, E.R., Zoback, M.D., Blackwell, D.D. (Eds.), Neotectonics of North America. Decade Map, vol. 1. Geologic Society of America, Boulder, CO, 423–436.

Blackwell, D.D., and many collaborators, 2011. Heat flow map of the conterminous United States, Google.org/egs, 2011.

Blackwell, D.D., Waibel, A.F., and Richards, M. 2012. Why Basin and Range systems are hard to find: The moral of the story is they get smaller with depth! Transactions, Geothermal Resources Council, 36, 1321-1326.

Crowell, A.M., Oschner, A.T., and Gosnold, W. 2012. Correcting bottom-hole temperatures in the Denver Basin. Transactions, Geothermal Resources Council, 36, 201-206.

Deo, M., Roehner, R., Allis, R., and Moore, J.N. 2013. Reservoir Modeling of Geothermal Energy Production from Stratigraphic Reservoirs in the Great Basin. Proceedings, 2013 Stanford Geothermal Reservoir Engineering Workshop.

Ehrenberg, S.N., and P.H. Nadeau, 2005, Sandstone vs. carbonate petroleum reservoirs: A global perspective on porosity-depth and porosity-permeability relationships: AAPG Bulletin, v. 89/4, p. 435-445.

Entingh, D. and Mines, 2006. A framework for evaluating research to improve U.S. geothermal power systems. Transactions, Geothermal Resources Council, 30, 741-746.

GETEM, 2006. Technical Reference Manual, Volume 1. Entingh, D., Mines, G. Nix, G., Mansure, A., Bauer, S., Petty, S., Liversay, B. For DOE Geothermal Technologies Program, NREL Subcontract No. KLCX-4-44447-07, PERI Task 7040-007.

Grant, M.A., and Bixley, P.F. 2011. Geothermal Reservoir Engineering. Academic Press, 2nd Edition, pp. 378.

Gwynn M., Allis, R., Blackett, R., and Hardwick, C. 2013. New geothermal resource delineated beneath Black Rock Desert, Utah. Proceedings, 2013 Stanford Geothermal Reservoir Engineering Workshop.

Heilweil, V.M., and Brooks, L.E., eds., 2011. Conceptual model of the Great Basin carbonate and alluvial aquifer system. U.S. Geological Survey Scientific Investigations Report 2010-5193, pp. 191.

Kirby, S. M. 2012. Summary of compiled permeability with depth measurements for basin, igneous, carbonate, and siliciclastic rocks in the Great Basin and adjoining regions. Open File Report 602, Utah Geological Survey, pp. 9.

Lachenbruch, A.H. and Sass, J.H. 1977. Heat flow of the United States and thermal regime of the crust. In, Heacock, J.G. (Ed.), The Nature and Physical Properties of the Earth’s Crust. American Geophysical Union Monograph, vol. 20, 626–675.

Masbruch, M.D., Heilweil, V.M., and Brooks, L.E., 2012. Using hydrogeologic data to evaluate geothermal potential of the Eastern Great Basin. Transactions, Geothermal Resources Council, 36, 47-52.

Moore, J.N., and Allis, R.G. 2013. Contract Deliverable for Phase I Project: “Novel Geothermal Development of Sedimentary Basins of the United States”, Report prepared under DOE contract # DE-EE0005128.

Porro, C. Esposito, A., Augustine, C., and Roberts, B., 2012. An estimate of the geothermal energy potential in major sedimentary basins in the United States. Transactions, Geothermal Resources Council, 36, 1359-1369.

Sanyal S.K. and Butler, S.J., 2009. Geothermal power from wells in non-convective sedimentary formations – an engineering economic analysis. Transactions, Geothermal Resources Council, 33, 865-870.

Tester, J. W., Anderson, B., Batchelor, A., Blackwell, D., DiPippo, R., Drake, E., Garnish, J., Livesay, B., Moore, M.C., Nichols, K., Petty, S., Toksoz, N., Veatch, R., Augustine, C., Baria, R., Murphy, E., Negraru, P., Richards, M. 2006. The Future of Geothermal Energy, Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century, Massachusetts Institute of Technology, 2006.
http://geothermal.inel.gov/publications/future_of_geothermal_energy.pdf.