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Formation Pressure as a Potential Indicator of High Stratigraphic Permeability

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ABSTRACT

Reservoir and economic modeling shows that stratigraphic reservoirs with transmissivities of 3 – 10 Darcy-meters at 3 – 4 km (10,000 – 13,000 feet) depth and at temperatures of more than 175°C should be suitable for 100+ MWe-scale power developments, and have a levelized cost of electricity of about 10c/kWh. Questions about stratigraphic units at this depth are whether the potential reservoirs could be over-pressured, and whether adequate permeability could be found in this depth range. An evaluation of hundreds of formation pressure data derived from drill stem tests (DSTs) in oil exploration wells in prospective basins of the western U.S. shows that in the Great Basin, pressures everywhere are hydrostatic to the total depth of the wells. This is interpreted as widespread lateral permeability beneath individual basins with short-circuits to the near-surface at the basin flanks and in the adjacent ranges. These results are consistent with inter-basin groundwater flow inferred from hydrologic evidence in carbonate aquifers across an area of ~ 2 x 10^5 km^2 beneath the eastern Great Basin (Heilweil and Brooks, 2011; Masbruch et al., 2012).

Formation pressure trends derived from DST measurements in deep wells that penetrate high-permeability Mississippian carbonate units beneath the Paradox Basin (Utah), the southeast Piceance Basin (Colorado), and the northern Wind River Basin (Wyoming) all show hydrostatic pressure from near-surface to depths exceeding 6 km (20,000 feet) despite over-pressures in low permeability units above the carbonates. In the case of the Paradox Basin, the deep carbonate units have the same pressure profile over an area 10^4 km^2 (0.5 x 10^4 $miles^2$) and appear to be in equilibrium with a regional head controlled by the elevation of the Colorado River. Possibly a normally-pressured, hydrostatic condition in deep stratigraphic units is an indicator of laterally extensive high-permeability.

1. INTRODUCTION

The subsurface pressure regime provides important constraints on the potential fluid flow regime within and between formations, and similarly, on a basin scale. In the petroleum exploration industry, abnormal overpressures are frequently associated with unconventional hydrocarbon accumulations, especially basin-centered, tight-gas accumulations (Law and Spencer, 1998; Nelson, 2003). Recent attention has been drawn to abnormal pressure regimes in shale formations and the possible value of thick shale formations as repositories for spent nuclear fuel in the U.S. (Neuzil, 2013). In geothermal systems, the pressure regime can be important for distinguishing whether the system is controlled by outflow at the ground surface, a shallow groundwater outflow plume, or deeper recharge. The lower density of hot water compared to cold water means there is usually an upward driving force within the system which often results in hot spring occurrences where there is adequate vertical permeability such as from faults. High permeability at shallow depth frequently acts as the pressure control for the underlying hydrothermal plume.

The purpose of this paper is to investigate pressures reported in deep wells drilled in the eastern Great Basin and whether the pressure regimes offer insights on regional-scale permeability at depth. Basin-centered geothermal resources, where near-horizontal, permeable formations contain hot water at 3 – 4 km depth (10,000 – 13,000 feet), may have significant power potential (Allis et al., 2012, 2013). However, an important issue is whether these formations may be over-pressured due to their depth and also due to overlying confining layers. There has also been informal skepticism amongst some experienced geothermal developers that sufficient permeability for a viable geothermal reservoir can be found at depths greater than 3 km (10,000 feet). Laterally varying pressure and over-pressures may indicate reservoir compartments, overlying confining units, and (or) limited regional (stratigraphic) permeability. Substantial oil and gas reserves exist at depths of more than 4.6 km (15,000 feet) in both clastic and carbonate reservoirs in U.S. basins (Dyman et al., 1997). However, there is a question whether these reservoir rocks may become ductile, and (or) if pervasive diagenesis, may make them relatively impermeable at the target temperatures of at least 175 - 200°C required for economic geothermal development.

There is scant published information on the undisturbed pressures in geothermal wells in the Great Basin, although Entingh et al. (2006) indicate pressures are generally at or below hydrostatic pressure from the ground surface. The maximum depth of geothermal wells in the Great Basin is typically less than 3 km (10,000 feet), with the production wells at Beowawe and Dixie Valley encountering high permeability down to about 2.8 km (9000 feet). Although many oil and gas exploration wells have been drilled in the Great Basin, there appears to have been no systematic review of the subsurface pressures they encountered. Most of these wells have been drilled in the eastern Great Basin due to the presence of petroleum source rock, and some oil production (Schalla and Johnson, 1994). Underlying the eastern Great Basin, is a carbonate aquifer system which influences inter-basin flow at depth (Williams and Sass, 2006; Heilweil and Brooks, 2011; Masbruch et al., 2012), and which has been identified as a possible geothermal reservoir target where the temperature is high enough (> 175°C; Allis at al., 2013).

In the second part of this paper the deep pressure regime compiled for the eastern Great Basin is contrasted with examples of the deep pressure regime beneath several basins on the Colorado Plateau and the adjacent Rocky Mountains physiographic province. Figure 1 shows the major basins and the locations of features mentioned here.

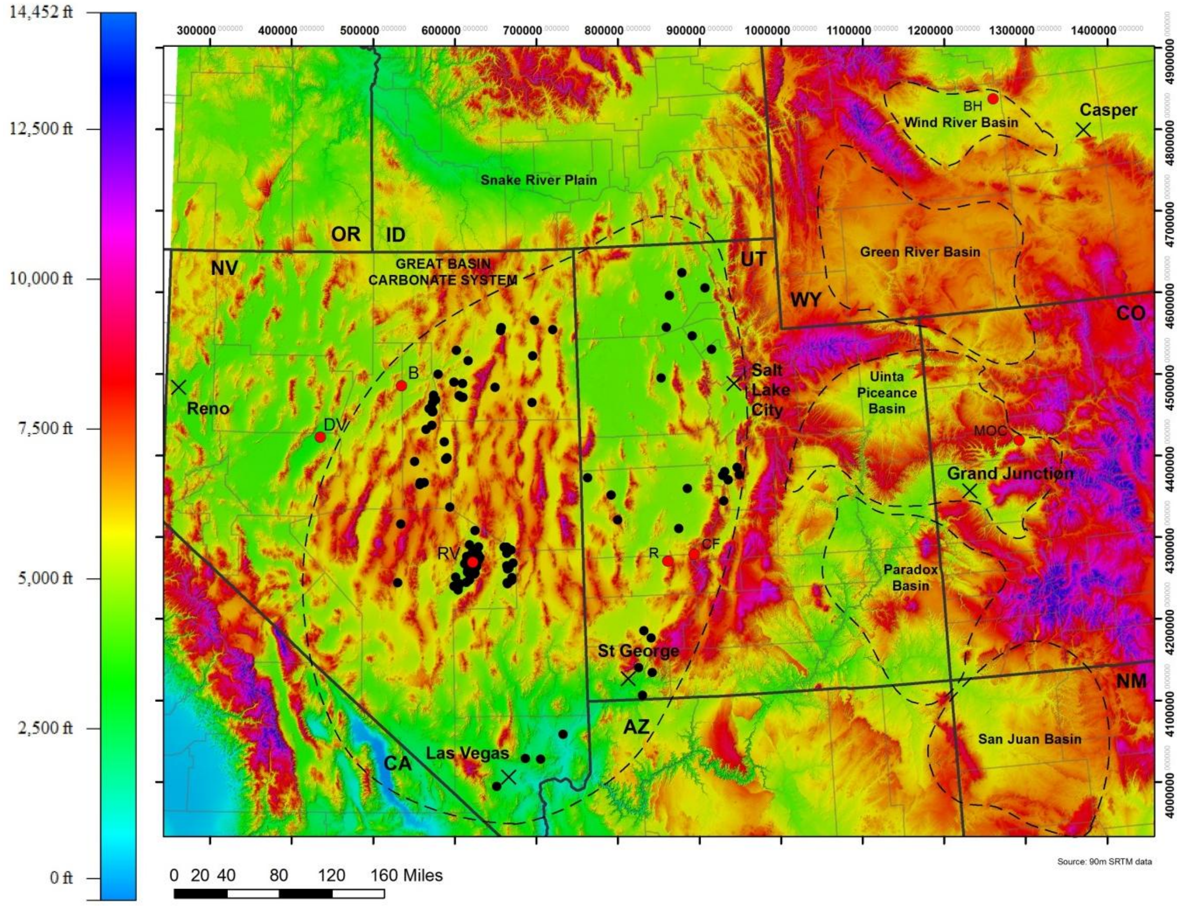


Figure 1. Colored relief map highlighting the Great Basin Carbonate System that underlies the eastern Great Basin. Petroleum wells in the Great Basin which yielded drill stem tests (DSTs) are shown as black dots. Major basins in the adjacent Colorado Plateau and Rocky Mountains physiographic regions are also identified. The dark dots are geothermal developments at Dixie Valley (DV), Roosevelt Hot Springs (R), Beowawe (B), and Cove Fort (CF); also marked are the Railroad Valley oilfields (RV) in the Great Basin, the Mobil O'Connell F11X-34P well (MOC) in the eastern Uinta-Piceance Basin, and BHP #2-3 Bighorn well (BH) in the Madden Deep Unit of the Wind River Basin. The ticks around the outside of the figure are at 100 km intervals.

2. DATA SOURCE AND METHODOLOGY

In most geothermal wells, direct measurement of both the temperature and pressure profiles are made providing information on which zones may be at or near the boiling point. Occasionally these measurements are made as a well heats up after cold water injection testing, and the pivot of the pressure profiles with heating identifies the dominant zone of high permeability (feedzone) and therefore the pressure-control point in the well (Grant and Bixley, 2011). This effect highlights the importance of knowing the density of the water column in the well, and the need to correct for this if only a water level is known. However, in oil exploration wells fluid pressure profiles (logs) are rarely run, and pressures must be derived from DSTs. Packers are set above and below the target zone, and if the packers don't fail, the DST measurements apply specifically to that open zone between the packers.

In this paper, formation pressures from oil and gas wells have been extracted from reports of DST results (from compilations by PI Dwights, licensed data provided to Utah Geological Survey). The critical measurement is the final shut-in pressure (fsip) which ideally should be the formation pressure if the shut-in time after flow testing is sufficiently long, and the permeability of the open interval is high enough. Figure 2 shows a recent example of a DST, with both pressure and temperature monitored during an 18 hour test. Although there was minimal inflow from the formation during the two flow periods of 0.5 and 1 hour duration (due to poor permeability), there was sufficient time (1 hour) after the second flow period for the pressure to almost recover to a stable value. The "apparent hydrostatic pressure" recorded at the start and end of the measurement period reflects the weight of mud in the well above the tool and not the country rock pressure (in this case the formation pressure is 2810 psi).

The "shut-in" pressure values included with this paper have been used without correction for recovery to equilibrium. This is a noisy dataset, so criteria were applied to screen out obviously inaccurate data. The most common source of error is incomplete pressure recovery because of low permeability, either due to local mud-cake problems or inherently low permeability in the formation (Bredehoeft, 1965; Nelson, 2003). If the shut-in time was less than about 30 minutes, or there was no shut-in time recorded, the shut-in pressure was discarded. While the 30-minute threshold sometimes appeared to indicate reliable data for the most permeable formations such as the Mississippian Limestone, it was far too short for low-permeability rocks. Even after 240 to 300 minutes, pressures in many reported "shale" formations and all "salt" formations (e.g., in the Paradox Basin, Utah) were still clearly far from equilibrium. Most DSTs reported an "initial" and a "final" shut-in pressure, and in such cases the larger of the two values was chosen. Any shut-in pressure less than about 50% of the hydrostatic pressure recorded in the test were excluded because they are hydraulically implausible and represent incomplete recovery. As discussed by Nelson (2003), there is always a risk of excluding apparently very low formation pressures due to inferred non-equilibrium, but if a pattern of lower pressure systematically correlates with a region or with formations that typically yield valid pressures, these data should be preserved. No such regions were found in this study. Any DSTs that did not identify the formation being tested, or had incomplete depth information, were also eliminated. The pressures inferred from the DSTs were assumed to coincide with the midpoint of the open interval identified in the test.

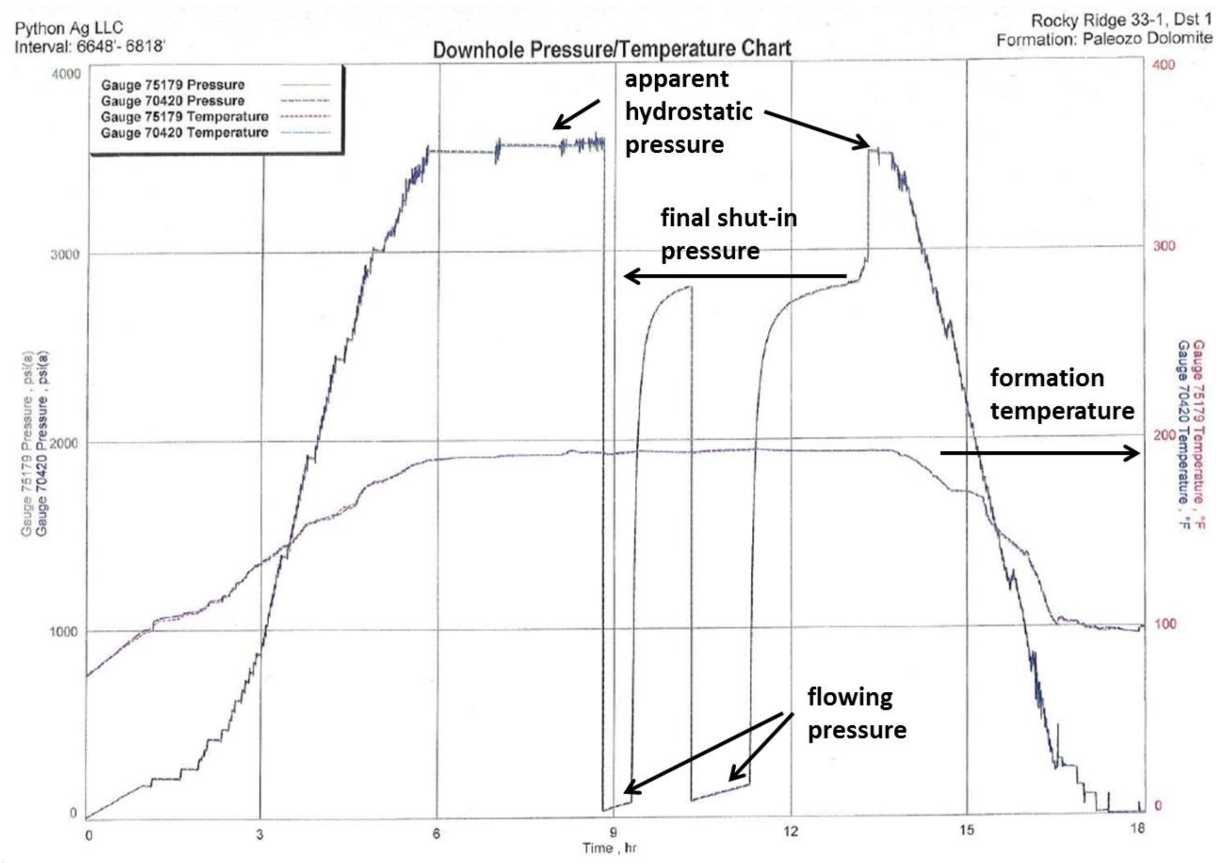


Figure 2. Example of a drill stem test from petroleum exploration well Rocky Ridge 33-1 drilled by Python Ag LLC in 2010 (report accessed at http://oilgas.ogm.utah.gov/wellfiles/027/4302750001.pdf). In this case the interval tested is between 6648 and 6818 feet depth, the formation pressure derived from shut-in pressures is 2810 psi (absolute), and the temperature at that depth is 195°F (91°C).

As a result of this screening process, between 50 and 75% of the pressure data were removed from further study. Within the eastern Great Basin, 245 DSTs were used from 143 wells in Nevada (some wells had DSTs at several depths); 40 DSTs were used from 25 wells in Utah. Pre-development pressure data is also available for three geothermal systems within the study area (Roosevelt Hot Springs, and Cove Fort, Utah, and Beowawe, Nevada). In each case, the data were taken from publications where pressures from wells with different depths allowed a pre-development pressure profile to be established (Garg et al., 2007; Allis and Larsen, 2012; ENEL, 2012; Ross and Moore, 1985).

The inferred formation pressure data is plotted separately against elevation and against depth. The type of plot is illustrated in Figure 3, modified from Nelson, (2003). Normally pressured formations lie along a gradient of 0.43 psi/foot (0.1 bar/meter) for cold, non-saline water. The gradient decreases by 20% for hot water depending on the temperature (non-saline water at 200°C, 392°F, has a density of 860 kg/m^3). When pressures are plotted against elevation, care is needed in interpreting the results over large regions with varying topography. Some wells on a pressure-elevation plot may appear to have anomalously low pressure trends, but this may be due to large variations in topography and associated lateral variations in hydrostatic trends from near the ground surface. This effect disappears when the data is shown on a pressure-depth plot. Anomalously low pressure trends on a pressure-depth plot likely indicates the water table is significantly below the ground surface.

3. EASTERN GREAT BASIN PRESSURE TRENDS

The pressure data from the eastern Great Basin has been plotted separately by state, and within each state by county. This allows some geographic detail, although it turns out the main factor causing lateral variations across the eastern Great Basin is ground elevation. The distribution of wells is shown on Figure 1.

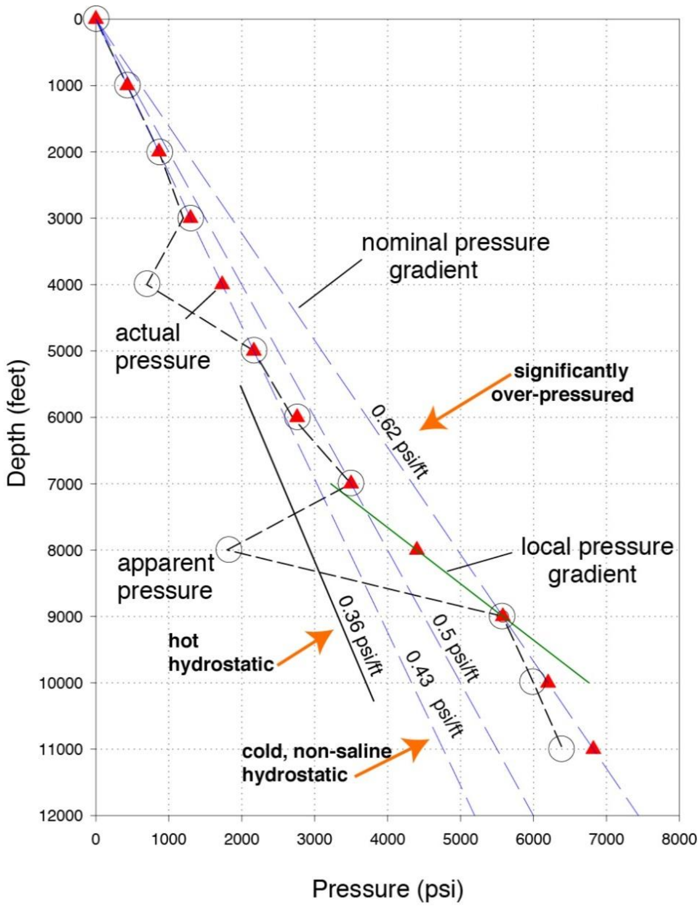


Figure 3. Illustration of pressure trend with depth showing normal hydrostatic pressure gradient for fresh water (0.43 psi/foot), significant over-pressured gradient (0.62 psi/foot), and comparison with a hot hydrostatic gradient (0.36 psi/foot) in a geothermal system with a temperature of 220°C (428°F; figure modified from Nelson, 2003). Two "apparent pressure" points are shown, which can be excluded when considering the trend from the other data (due to incomplete pressure recovery due the DST measurement.).

The pressure data for the Nevada portion of the eastern Great Basin are plotted in Figure 4A. When plotted against the elevation of the DST, there is evidence of parallel trends with the same hydrostatic gradient of 0.43 psi/foot. Most obvious are the data for Clark County. This county has the lowest surface elevations (in southeast corner of the state), and shows a hydrostatic trend that extends to 5.2 km (17,000 feet) below sea level. Its zero-pressure intercept of 600 m (2000 feet) above sea level (asl) is close to the local ground level.

The effect of varying topography is removed by plotting all the data against depth, with the data clustering more closely around a hydrostatic line (Figure 4B). Most of the data suggests hydrostatic slopes that have zero pressure intercepts of between 0 and 300 m (1000 feet below the ground surface, and imply regionally extensive heads significantly below the ground surface. This is consistent with regional-scale, interbasin groundwater flow in thick permeable carbonate units at depth (Heilweil and Brooks, 2011; Masbruch et al., 2012). There is no evidence of over-pressures.

The only geothermal data in eastern Nevada that was available for this study is from Beowawe. The nearest DST data from oil wells are about 50 km (30 miles) to the southeast in Pine Valley (Blackburn oil field; Eureka County) and these wells are typically 150 – 300 m (500 – 1000) feet higher in elevation than Beowawe geothermal wells (in Crescent Valley). Figure 5 shows the pressure trends plotted as depth below the wellheads. The lower pressure gradient at Beowawe is consistent with the lower density of the hot hydrostatic column (water temperature (180°C; 356°F.)

Pressure data from western Utah are compiled in Figure 6. The pattern is similar to that found for eastern Nevada – the data show hydrostatic gradients, with the principal factor separating trendlines being the elevation of the ground surface. However, there are less data and the scatter is greater. There is no evidence of over-pressures. The undisturbed, deep liquid pressure trends from two developed geothermal reservoirs show lower density profiles due to the reservoir temperature (~ 250°C at Roosevelt Hot Springs, and ~ 160°C at Cove Fort; Allis and Larsen, 2012; Ross and Moore, 1985; and ENEL, 2012). At Roosevelt Hot Springs the zero pressure value (head) appears to be slightly higher than the ground surface and is consistent with extensive hot spring deposits. At Cove Fort, the head of the hot water reservoir is between 300 and 430 m (1000 and 1400 feet) below the local ground surface, most likely because of pressure control from groundwater about 16 – 24 km (10 to 15 miles) to the northwest (groundwater information in Kirby, 2008.) There is a perched groundwater zone at Cove Fort with a head approximately 300 m (1000 feet) higher than the head of the underlying hot water. Another exception is the five wells in Iron and Washington County suggesting equilibration with groundwater at about 600 m (2000 feet) depth and with a head at about 900 m (3000 feet) asl, likely controlled by groundwater a few tens of km to the southwest (south of St. George) where the ground surface and regional drainage are at a much lower elevation. The recent groundwater study by Inkenbrandt et al (2013) also found the potentiometric surface of deep groundwater south of St. George to be at about 900 m (3000 feet) asl.

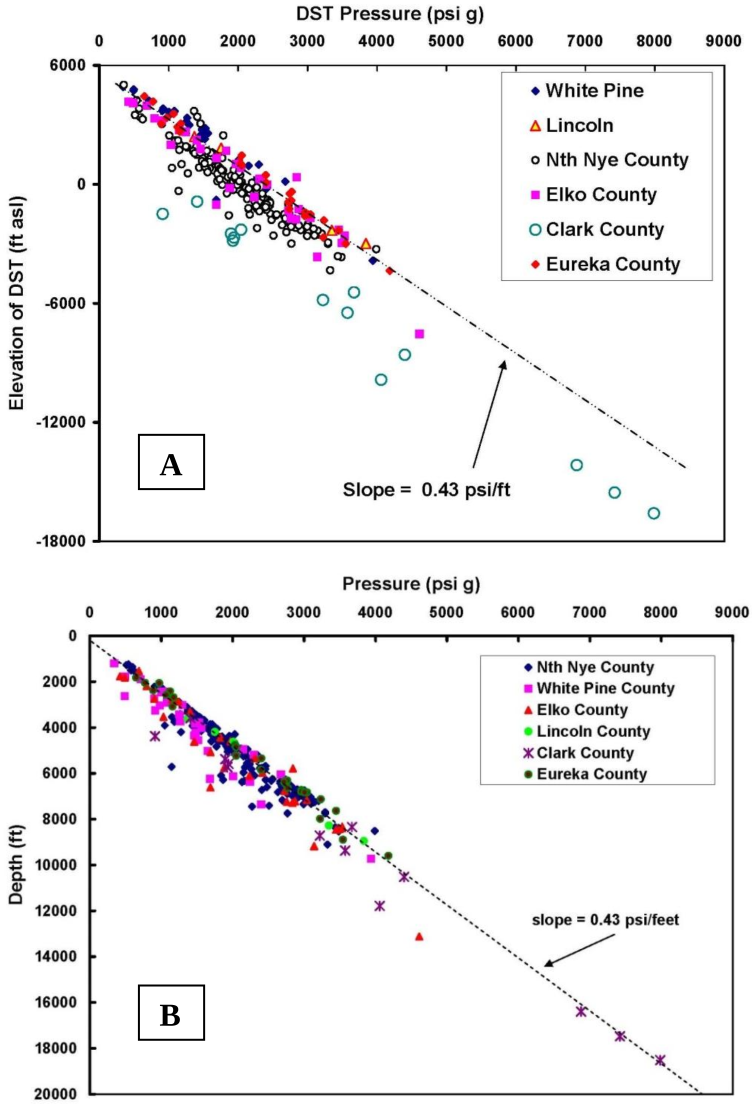


Figure 4. A. Formation pressures inferred from DST measurements in oil exploration wells in eastern Nevada plotted against elevation and B. Depth below the wellhead (lower graph). The distribution of the wells is shown in Figure 1.

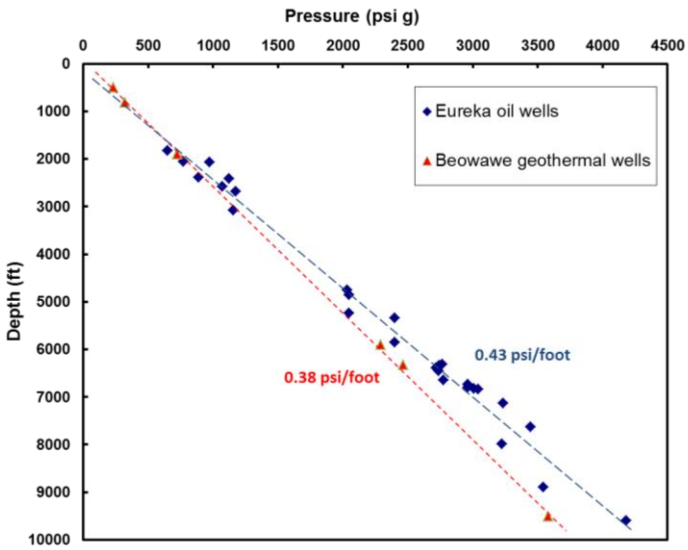
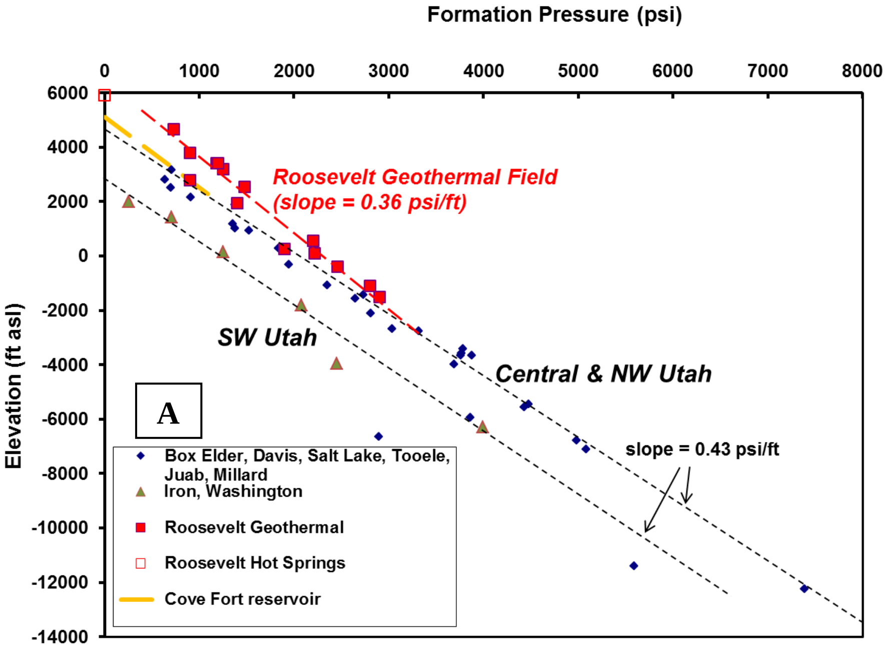


Figure 5. Pressure trends at Beowawe geothermal field and in Pine Valley (Eureka County) oil wells about 50 km (30 miles) to the southeast. Both trends are consistent with hydrostatic conditions for the density (temperature) of the fluids.



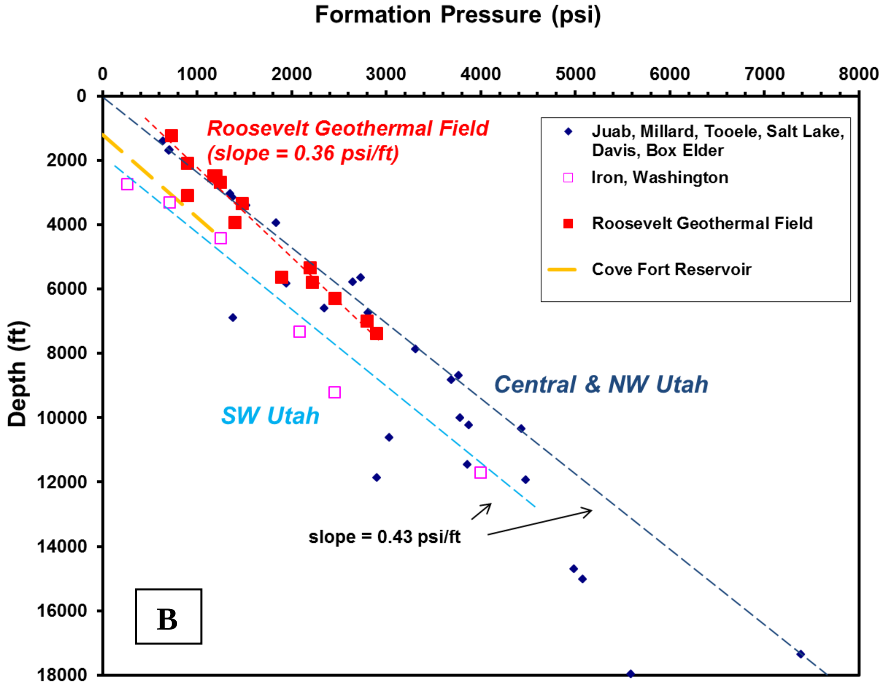


Figure 6. A. Formation pressures inferred from DST measurements in oil exploration wells in western Utah plotted against elevation, and B. Depth below the wellhead (lower graph). The distribution of the wells is shown in Figure 1. The trends are consistent with hydrostatic conditions when water temperature and fluid density is accounted for.

4. DISCUSSION

Abnormal pressure regimes at depth are frequently attributed to compaction disequilibrium, particularly in basins with relatively rapid sedimentation, and to hydrocarbon generation (Swarbrick and Osborne, 1998; Hunt et al., 1998). Depending on the vertical extent of fine-grained sediments, over-pressures may occur as shallow as 2 km (6600 feet) depth. In the eastern Great Basin, despite a wide range of basins up to 4.6 km (15,000 feet depth, and with up to about 3 km (10,000 feet) of sedimentary infill within the last 15 million years, there is no sign of significant over-pressures in DST measurements in oil exploration wells. This includes the oil producing area of Railroad Valley, eastern Nevada. The three geothermal systems, Beowawe (Nevada), Roosevelt Hot Springs and Cove Fort (Utah), each have multiple wells with varying feedzone depths, and show composite vertical pressure gradients that are consistent with hydrostatic conditions for the average reservoir temperature and fluid density.

Most pressure trends suggest the dominant control is local and consistent with hydrostatic pressures of unconfined groundwater. These trends have a zero-pressure intercept within about 150 m (500 feet) of the ground surface at the wellhead. The scatter in the data precludes a more accurate estimate of this depth. The obvious exception is at Cove Fort, and other local exceptions are perched groundwater aquifers overlying lower-pressure deep groundwater near the incised Colorado River.

It is instructive to compare the regional pressure patterns beneath the eastern Great Basin with pressure trends in several major basins of the Colorado Plateau and adjacent Rocky Mountains physiographic provinces. The Paradox Basin (mostly Utah), the southeast of the Uinta-Piceance Basin (Utah and Colorado), and the deep Madden play of the northern Wind River Basin (Wyoming) all have evidence of widespread hydrostatic conditions at depth in carbonate reservoirs despite strong over-pressures at shallower depths (basin locations on Figure 1). These basins have significant hydrocarbon production, and hydrocarbon generation widely is interpreted as the dominant cause of the over-pressures.

In the Paradox Basin of southeastern Utah and southwestern Colorado, despite large lateral variations in pressure with depth in shallow parts of the basin, the deeper, lower Paleozoic carbonate units show a remarkably uniform, hydrostatic pressure regime over an area of more than ~ 10^4 km^2 (0.5 x 10^4 square miles), Figure 7; Allis et al., 2008). This pattern is analogous to the uniform pressure trends described above for the eastern Great Basin carbonate system, and presumably is indicative of widespread, high lateral permeability within these carbonate units. In some parts of the Paradox Basin such as the west Green River quadrangle, the vertical pressure is hydrostatic from the ground surface to at least 3 km (10,000 feet) depth. However, in the Aneth quadrangle, the pressure trends are more complicated (Figure 8). Near-surface formations (Permian and younger) at Aneth have a hydrostatic trend that is equilibrating with groundwater in the nearby stretch of the San Juan River drainage system, and the potentiometric head is between 1400 and 1500 m (about 4500 and 5000 feet) asl. Some of the higher pressure, Permian data in this quad are significantly north of Aneth field where both ground elevations and the unconfined groundwater aquifer rise in elevation. Wells around the town of Blanding near the southeast flanks of the Abajo Mountains have water levels at 1650 m (5400 feet) asl (Kirby, 2008).

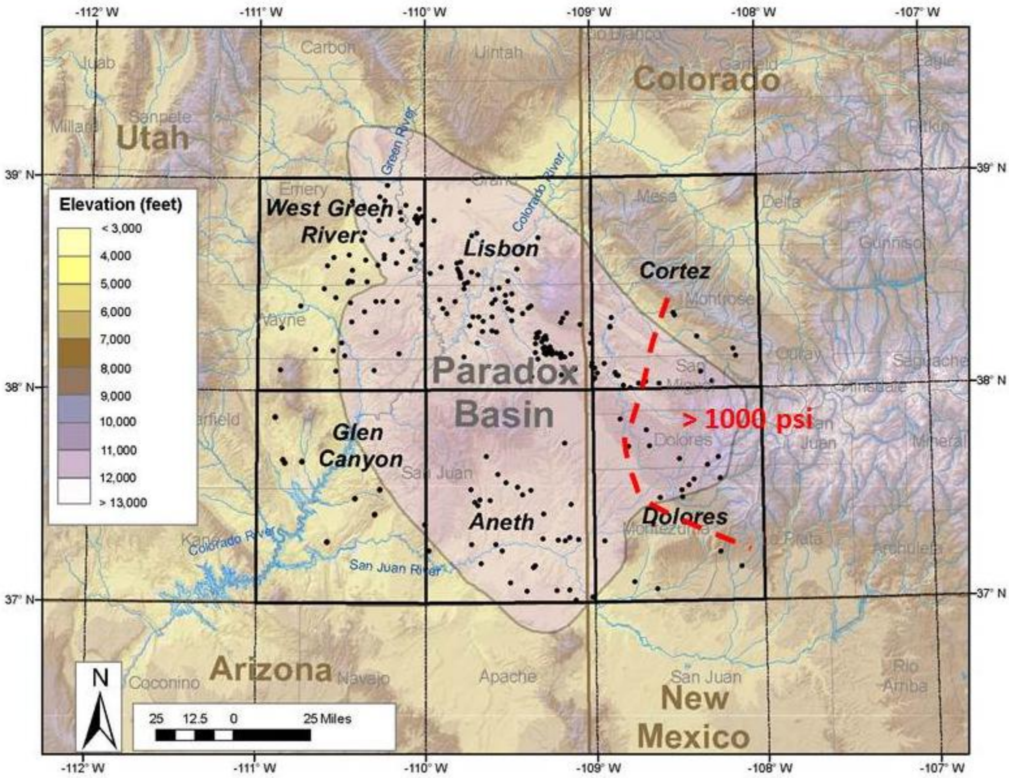


Figure 7. Shaded relief map of the Paradox Basin, southeast Utah and southwest Colorado (Allis et al., 2008.) Dots are the locations of wells where DSTs have been used to establish the formation pressure trends. The basin has been divided into 1 degree quadrangles, with the trends in West Green River and Aneth highlighted in Figure 8. The red dashed contour outlines the part of the basin where Mississippian and older units in the basin are over-pressured by more than 1000 psi compared to the hydrostatic trend elsewhere for these units. Over most of the basin, Mississippian and older units have a pressure that is close to hydrostatic with a potentiometric head of 1160 to 1220 m (3800 to 4000 ft) asl.

Within the Mississippian and older carbonate units at greater depth in the Aneth quadrangle, there is another hydrostatic trend which appears to be equilibrating with the San Juan River where it crosses the Monument Upwarp and is at an elevation of 1160 m (3800 ft) asl (close to the boundary between the Aneth and Glen Canyon quadrangles on Figure 7.) On the crest of the upwarp, the Mississippian is about 150 m (500 feet) below the San Juan River (Tom Chidsey, pers. comm.) Between the Permian and Mississippian pressure trends in the Aneth quadrangle is a wide range of pressures within the Pennsylvanian section. The Aneth oil field is Utah's most prolific oilfield, with most production coming from Pennsylvanian formations. Significant over-pressures range up to 0.8 psi/ft, and pressures are up to 2000 psi higher than the Mississippian hydrostatic pressure trend at the same elevation (Figure 8.)

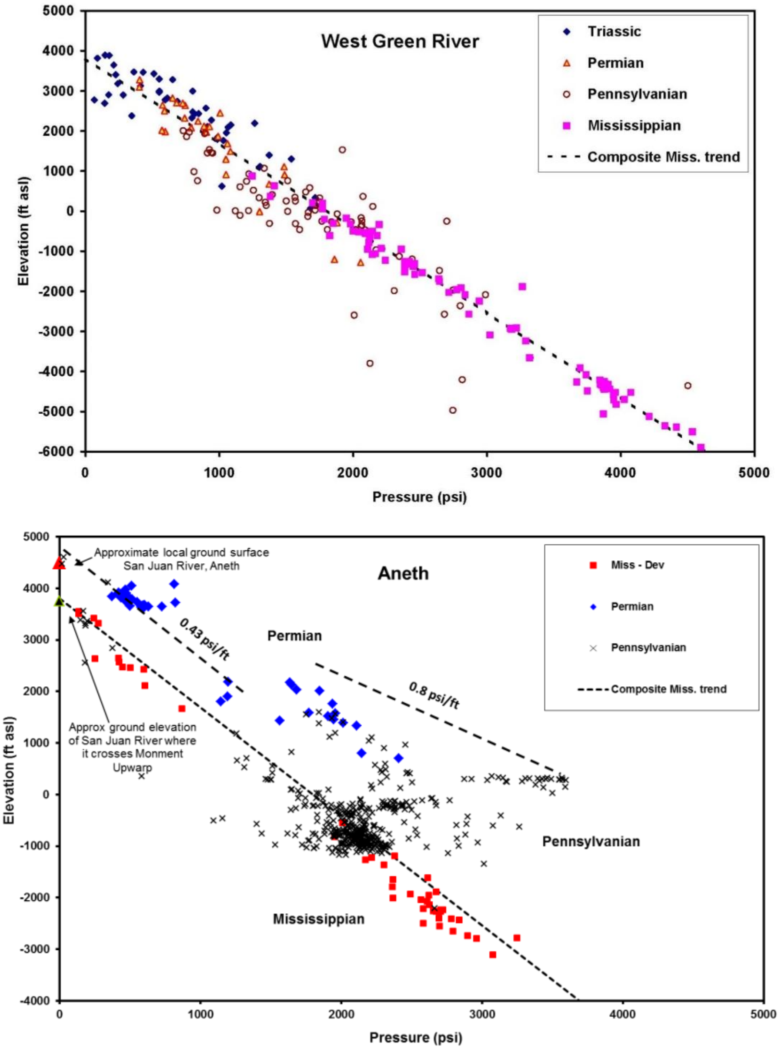


Figure 8. Examples of vertical formation pressure trends in two, 1-degree quadrangles (West Green River and Aneth) in the Paradox Basin (plotted at elevation of DST). The dashed line labeled "composite Mississippian trend" is the general pressure trend (0.47 psi.ft) for the Mississippian across the whole basin, excluding the over-pressured region in the east of the basin depicted in Figure 7.

Recognition of widespread under-pressures in the Mississippian at Aneth compared to the pressure in overlying units is not new. Peterson, (1992; pressure chart compiled by Powley; no reference given) noted that there appeared to be no seal, and the Mississippian System may have been breached by erosion at an elevation of 1250 m (4100 ft asl). Inclusion of additional DST data here confirms this general conclusion, although the potentiometric head is slightly lower, and hydrologic control is likely to be further west beneath the San Juan – Colorado River system. Compilation of Mississippian formation pressures from the whole of the Paradox Basin shows regional control by the Colorado River, and a hydrostatic gradient everywhere which is attributed to the high permeability of the carbonates. The eastern boundary of hydrologic control by the Colorado River system within the Mississippian is situated within the Cortez and Dolores quadrangles of Colorado (Figure 7).

In the southeast Uinta-Piceance Basin, the deep Mobil O'Connell well (F11X-34P) found a pressure pattern similar to that at Aneth, and also confirmed that the Mississippian Leadville carbonate unit had excellent porosity, high permeability, and a hydrostatic pressure gradient (Wilson et al. 1998). Several over-pressure zones were encountered at shallower depth: in Upper Cretaceous Mesaverde Group coal measures, in Upper Cretaceous Niobrara marine shales, and in Pennsylvanian units with mixed lithologies (Figure 9.) However, the underlying Mississippian carbonate formation at 5.6 km (18,400 feet) is normally pressured. Widespread karstification and porosity development in dolomite and limestone beds of the Leadville Formation have resulted in regionally good porosity and permeability (DeVoto, 1985; Robertson et al., 1995). Measured temperatures at total depth in this well ranged up to 239°C (464°F), demonstrating that carbonate units at these depths and temperatures can still preserve high quality reservoir properties.

Another example of widespread high permeability and hydrostatic pressures occurs in the Madden Deep Unit of the Wind River Basin (Figure 10; labeled BH in Figure 1.) Brown and Shannon (1989) describe the drilling of 2 wells that reached 7.3 km (24,000 feet) depth, and encountered high permeability in Mississippian Madison carbonate near their total depth. After stimulation with acid, initial production rates from the Lower Madison units in the two wells were 20 and 38 million cubic feet of gas per day, which implies high-productivity wells. The production interval is described as interbedded limestone and dolomitic limestone. No water was produced, and the gas composition was 68% methane, 20% carbon dioxide, and 12% hydrogen sulfide. The maximum recorded temperature was 216°C (416°F).

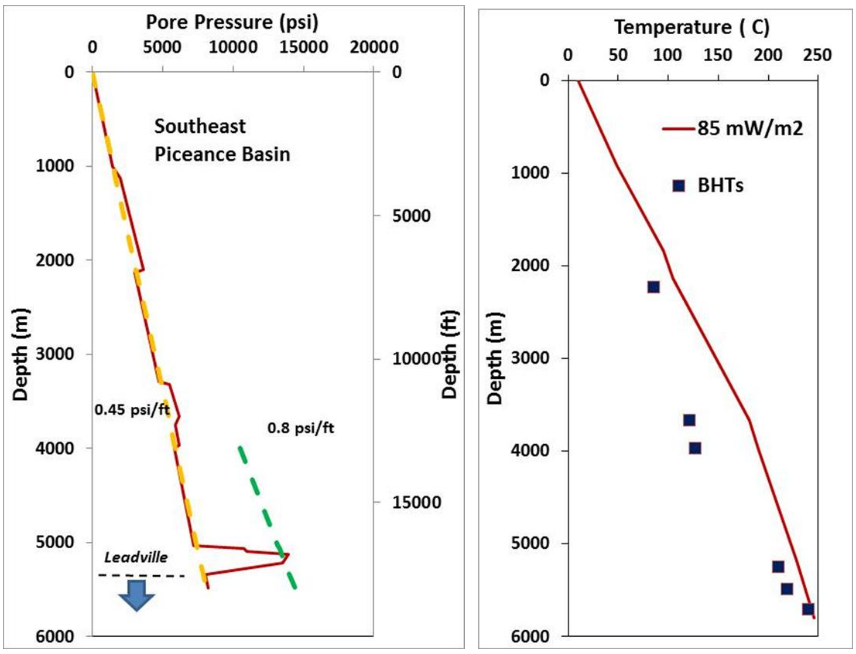


Figure 9. Example of moderate over-pressures in Cretaceous formations of the Piceance Basin, western Colorado, and strong overpressures in the Pennsylvanian section (Wilson et al., 1998; well Mobil O'Connell F11X-34P). The underlying Mississippian carbonate section is normally pressured and has high permeability.

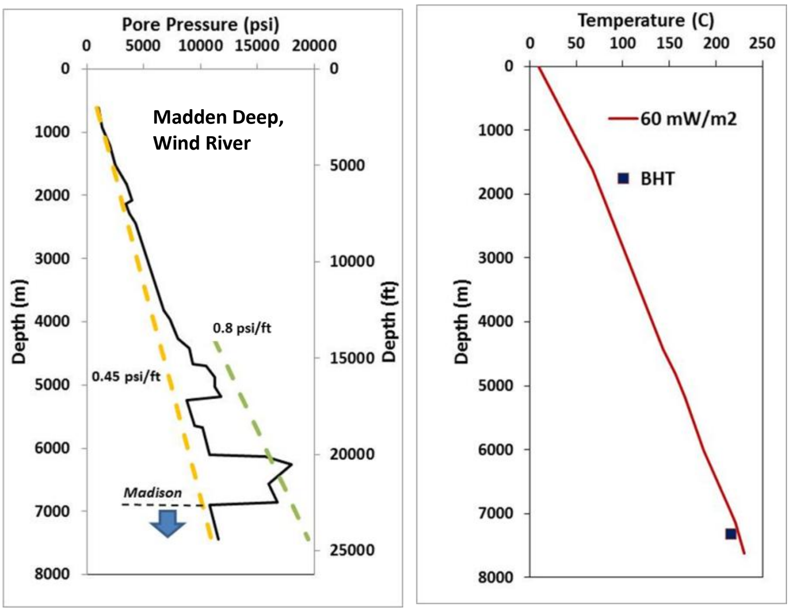


Figure 10. Example of moderate over-pressures in Cretaceous formations of the Deep Madden Field of the Wind River Basin, and near-normal hydrostatic pressures in Mississippian Madison carbonates at 7.3 km (24,000 feet) depth (Brown and Shannon, 1989; well #2-3 Bighorn). The Madison has reservoir properties and has subsequently been developed for its sour gas reserves.

5. CONCLUSIONS

A study of pressure trends in the carbonate aquifer system beneath the eastern Great Basin has found no evidence of over-pressures in wells ranging up to more than 4.6 km (15,000 feet) deep. The pressure data comes mainly from DSTs in petroleum exploration wells, and they include measurements in oil fields, geothermal fields, and regions of high and low heat flow. The prevalence of hydrostatic conditions from near to the ground surface is consistent with the unconfined conditions generally found in carbonate aquifers underlying the eastern Great Basin (Heilweil and Brooks, 2011). This model implies high, basin-scale, stratigraphic permeability within lower Paleozoic carbonate units in particular, and requires pressure connection to the surface through the numerous extensional faulting characteristic of the Great Basin. The normally-pressured area exceeds 2 x 10^5 km^2 (~ 10^5 $miles^2$).

A large area (at least 10^4 km^2; 0.5 x 10^4 square miles) with uniform hydrostatic pressure also exists within lower Paleozoic carbonate units in the Paradox Basin, Utah, despite parts of the basin having significant over-pressure in overlying formations. The uniformity of deep pressure implies high lateral permeability and the dominant pressure control appears to be where the lower Paleozoic section rises to less than 300 m (1000 feet) depth beneath the Colorado – San Juan River system.

Wells in the southeast Piceance Basin and the Madden field of the Wind River Basin also confirm that normal pressure regimes and high stratigraphic permeability occur in predominantly carbonate formations at depths of between 5 and 7 km (16000 and 23000 feet), and temperatures of 220 to 240°C. Their near-hydrostatic gradient from the ground surface despite significant over-pressures at shallower depth indicates that the high stratigraphic permeability is laterally extensive, and it is likely that the hydrostatic pressure control is occurring in fault zones at the boundaries of the basins.

Although hydrostatic pressure in formations deep within basins is not a guarantee of high permeability in a prospective production well, it may be a secondary indicator of laterally extensive high permeability which is either stratigraphic, fracture-controlled, or some combination of both factors. This study has also confirmed that high permeability can be found in carbonate formations at depths and temperatures exceeding the target conditions for economic geothermal development of stratigraphic geothermal reservoirs (that is, 3 – 4 km depth, and > 175°C.)

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