Geothermal Battery Energy Storage

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ABSTRACT

The Geothermal Battery Energy Storage concept (GB) has been proposed as a large-scale renewable energy storage method. This is particularly important as solar and wind power are being introduced into electric grids, and economical utility-scale storage has not yet become available to handle the variable nature of solar and wind.

The Geothermal Battery Energy Storage concept uses solar radiance to heat water on the surface. This is then injected into the earth. This hot water creates a high temperature geothermal reservoir acceptable for conventional geothermal electricity production, or for direct heat applications. Storing hot water underground is not new, the unique feature of the GB is its application to sedimentary basins with formations that are water saturated and exhibit high porosity and high permeability. For certain reservoirs like these, calculations suggest that nearly one hundred percent of the stored heat can practically be recovered, and long-term, even seasonal storage is possible.

Several publications presented by the authors on the GB, parametrically identified desirable reservoir characteristics. This is a review of those calculations and the inferred conclusions for a viable GB system. Potential GB system well configurations, injection and production scenarios and ultimate heat recovery for economic value are noted.

Keywords: geothermal energy, renewable energy storage, solar heat, underground heat storage

1. Introduction

The concept of injecting heated water into nonpotable, underground aquifers to store heat for later recovery is not new.[1-8] Interest in large-scale energy storage has recently grown as solar and wind produced electricity have been introduced in higher quantities, and a practical and economic method is required to store that energy because of its intermittent nature.[2] Using solar radiance for surface water heating allows a renewable energy source for the heat that is to be stored.[9] Various studies have investigated temperature distribution, heat loss into surrounding regions, and ultimate heat recovery. Also, many studies of water and heat flow have been made for conventional geothermal energy recovery.[10] And, commercial geothermal energy applications of production and injection of water are being developed continually.[10] In most of these cases, regions of high geothermal gradient were considered, involving regions of large rock mass, most often with low formation porosity and low rock matrix permeability. These large rock-mass formations tend to be heterogeneous due to fracturing and faulting.[11]

Less emphasis has been placed on storing water heated to high temperatures in high porosity and high permeability formations away from complex layering and fractures and faults. For such a scenario, the rock mass of interest is relatively small. For example, a region of forty meters radius from an injection or production well in a permeable formation that is of one hundred meters thickness and of twenty percent porosity rock has the potential to store a huge volume of heated water, about twenty-seven million gallons. Production from this volume of stored fluid, at a rate of 40 kg/seconds (about 15 barrels per minute) for ten hours each day, could continue for over seventy days. Moreover, the availability of ideal formations relatively homogeneous in high porosity and high permeability rock is great, considering the relatively small volume of rock mass considered. A high geothermal gradient is not necessary, however the formation must be fully water saturated with an overlaying low permeability 'sealing' cap.

The concept of deep injection of hot water into sedimentary environments as noted above, was introduced in 2017 at a National Science Foundation (NSF) sponsored SedHeat meeting in Salt Lake City, Utah.[12-13] The concept was further considered at an NSF sponsored working group meeting in June 2017 in San Francisco, examining a Geothermal Battery Energy Storage idea.[14] In 2018-2019, the Idaho National Laboratory pursued calculations for heated water injection, referred to as "GeoTes" and presented final results in a publication[15,3,8] and a presentation by Kevin Kitz at the Geothermal Research Council annual meeting in October 2019.[5] At the same time, the GB was being pursued at the University of Utah via an NSF research grant with Professor John McLennan as the Principal Investigator.[16] The first publication from this work resulted in an American Rock Mechanics Association (ARMA) paper by Panja, Green, and McLennan to be presented at the 2020 ARMA Annual Symposium.[17] A second publication by Panja, McLennan, and Green is under review.[18]

Unless a large portion of the injected heat can practically be recovered, a GB cannot be economical; and, for the injected heat to be recoverable, the proper reservoir is essential. Thus, this paper focuses on the reservoir. Unfortunately, the reservoir is the least constrained of the design variables, as surface facilities can be engineered and to a large extent are based on commercial components. Because the reservoir is critical for a viable GB, this paper reviews reservoir considerations. Most of the figures showing calculation results are taken from references.[17-19] The effects of formation parameters on potential reservoirs for the GB are noted. This paper includes Section 2-Homogeneous and Isotropic Reservoirs, Section 3-Non-Isotropic Permeability Reservoirs, Section 4-Well Layout and Injection-Production Considerations, Section 5-Geochemistry Considerations, Section 6-Potential Sedimentary Basins of Interest, and Section 7-Geothermal Battery Energy Storage as a System. And, in the final section conclusions are presented.

For the calculation results shown here,[17-19] single well injection and production is considered. That is, production of the reservoir cold water needed simultaneously for the surface heating is not considered, nor is the reinjection of the produced hot water after it is cooled and is simultaneously reinjected back into a cold part of the reservoir. The calculations may be viewed as a single-well "huff-and-puff" system where hot water is injected for some time and then the hot water is produced from the same well for some time. Calculations shown here were made using the CMG Star software.[17-19]

2. Homogeneous and isotropic reservoirs

Calculated temperature and reservoir pore pressure profiles at increasing distances away from a well are shown for injections and production cases. Numerous calculations with parameter variations were made.[17-19] Parameters considered included porosity, permeability, reservoir thickness, the number and character of injection cycles, injection rate, rock thermal conductivity and specific heat, and reservoir initial temperature. Boundary conditions for the calculations included no-flow boundary and constant pressure boundaries, with distance to the boundary varied. In all cases, homogeneous and extensive low permeability, over- and underlying formations were prescribed. Various thermal conductivities of this over- and underburden were considered to ensure that conductive losses from the reservoir itself was not a significant consideration.

Most of the calculations were for an eight-hour injection, followed immediately by production of the same mass of water over ten hours, followed by thermal equalization for six hours-and then this cycle is repeated. In the accompanying figures, such cycles are shown as one-day cycles of injection-production. The "base-line" calculations were for injection of 250°C water into a horizontal formation "reservoir" initially at 120°C, at 40 kg/second (about 7200 barrels total over 8-hours) into a reservoir 110 meters thick with 15% porosity and 100 millidarcies permeability. The calculations used constant-pressure boundary conditions with the boundaries at various radial distances from the well, except as noted later where no-flow boundary conditions were considered. The over and under lying formations had 0.01 times the permeability of the formation reservoir. Porous sandstone thermal conductivity and specific heat (the rock itself), water conductivity and specific heat, and water viscosity as a function of temperature were used.[17-19] Although the injected mass of water was the same as the produced mass of water for the cycles, volumes are not the same because of density variation with temperature. Many parametric variations were considered, and unless noted specifically in the figures, the calculated results are for the "base-line" case.

2.1 Temperature profiles

Temperature profiles were compiled from the parametric calculations. Figure 1 shows temperatures at distance from the injection well after injection for eight hours, for "base-line" daily cycles. The hot water storage is close to the injection well. Reservoir temperature increases to a radial distance of only about 20 meters from the well, even after 100 daily cycles. As anticipated, variation in reservoir permeability had no significant effect on temperatures; porosity affects the temperature advance away from the well, as do reservoir thickness and injection volume. Thermal conductivity and specific heat of the water and the rock and thermal expansion/contractions of the water and the rock with temperature have little effect on the temperature profiles in these uncoupled simulations.

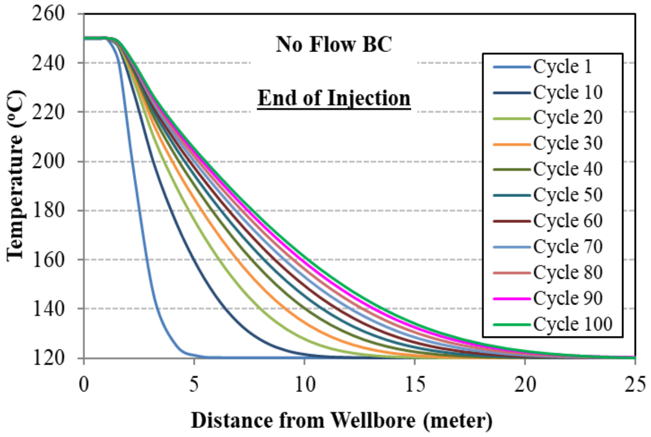

Figure 1 – Base-Line Temperatures Radially from the Wellbore

Even after 100 daily cycles of injection and production, the reservoir became heated to almost the injection high temperature to only about three meters from the well. Thus for this case, during production, wellbore losses ignored, the initial produced water temperature is near the maximum, but becomes lower as production continues. This is an important consideration for the overall efficiency.

Figure 2 shows wellbore temperatures for base-line daily cycles of injection, production, and stabilization. The horizontal axis is time in days. Wellbore temperature is at the bottomhole injection temperature during injection. It declines as production occurs, and declines slightly more during the stabilization time. For injection of water at 250°C, production temperatures after about fifteen cycles vary from 250°C down to about 220°C, with monotonic temperature reduction with production for each cycle. The temperature stabilization after about fifteen cycles, indicates that the "heat loss" is small (for example, approaching 5% for each cycle after one hundred cycles).[9] Later discussion will advocate for "charging" the reservoir by injecting for longer periods before production begins (Figure 4). This could allow total production to occur at the injection high temperature. Although not shown here, somewhat higher injection pressures occur and a significantly greater drawdown pressure results during production.[19] Both of these are due primarily to the greater viscosity of water at the lower temperatures.

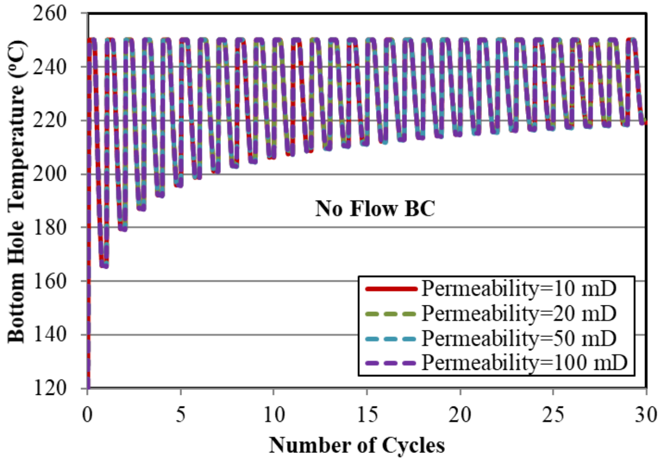

Figure 2 – Wellbore Temperature for 30 Daily Cycles

Figure 3 shows wellbore temperature cycles for a base-line case, except an initial reservoir temperature of 60°C is used instead of 120°C. For the daily cycles of injection-production, lower temperatures occur during production and stabilization.

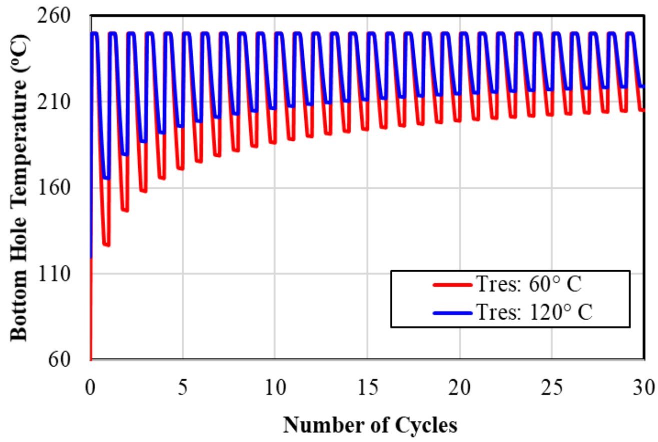

Figure 3 – Wellbore Temperature Cycles for 60°C Reservoir Initial Temperature

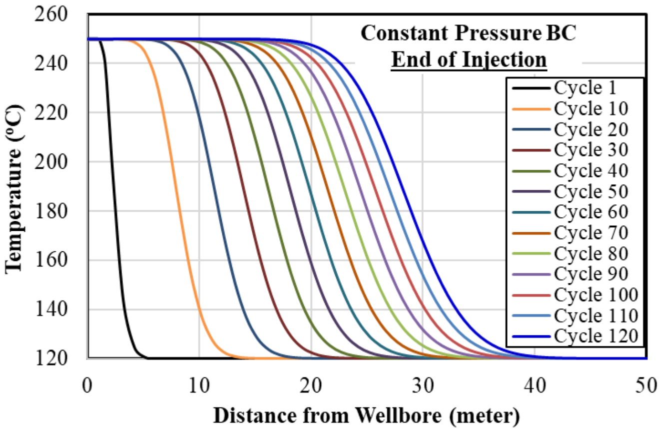

Figure 4 – Charging Reservoir by Injection without Production

Although not shown here, somewhat higher injection pressures occur and a significantly greater drawdown pressure results during production.[19] Both of these are due primarily to the greater viscosity of water at the lower temperatures.

Calculations were made to represent "charging" the reservoir by injecting for many days without any production—as seen with, monthly or seasonal storage. Figure 4 shows a base-line case, with the only exception that injection was carried out for 120 days (8-hours of injection each day at 40 kg/second water at 250°C) before production began. This charging of the reservoir led to "near injection water temperature" approximately 20 meters away from the injection well and elevated reservoir temperature out to about 40 meters. For this case, production for a substantial time would occur at the injection temperature of 250°C. Clearly charging the reservoir may have much advantage in order to maintain the production temperature at or near the injection temperature. Additionally, if the reservoir is "charged" prior to production, the initial reservoir temperature is not important. However, lower initial reservoir temperature will require somewhat longer to charge the reservoir to a given temperature.

2.2 Reservoir pore pressure

Reservoir pore pressure is much more complicated than temperature variations. Figure 5 shows the base-line case, except with different permeabilities as shown, for constant-pressure radial boundary calculations. For injection into high permeability formations (100 millidarcies) the wellbore pressure stays about constant, and remains nearly constant during production. During the equalization time, wellbore pressure returns to almost far-field reservoir pore pressure (12 MPa). As shown in Figure 5, permeability of the formation has a large effect on wellbore pressures, as expected from the character of fundamental radial flow relationships.

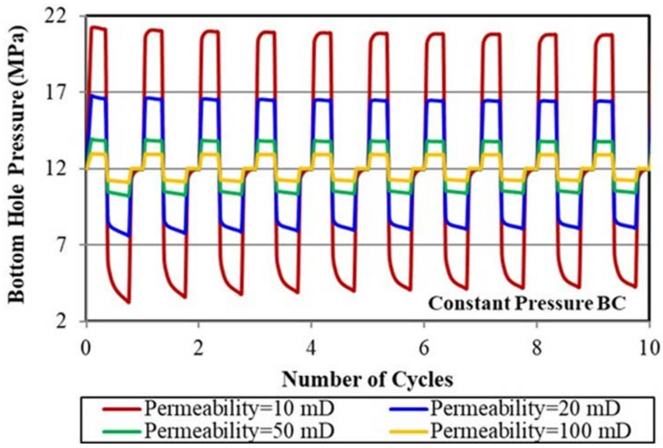

Figure 5 – Wellbore Pressure for Base-Line Case Constant-Pressure Boundary Calculations

As shown in Figure 5 for the base-line calculation (injection of 40 kg/second for 8 hours and production at 32 kg/second for 10 hours), permeabilities below about 50 millidarcies show significant increase in bottomhole injection pressure and decreases in production pressures. Wellbore pressures are relatively insensitive to formation porosities.

For the calculations, no-flow versus constant-pressure radial boundary conditions do not affect temperature profiles significantly, but can have a significant effect on reservoir pore pressure. For example, Figure 6 shows a base-line calculation with a radial no-flow boundary condition and radial constant pressure boundary condition.

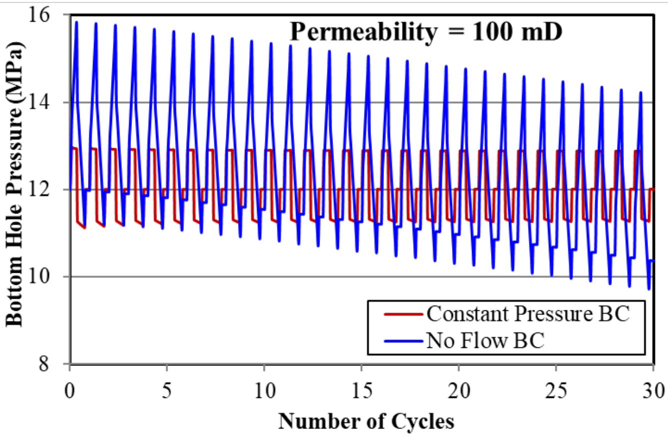

Figure 6 – Wellbore Pressure for Base-Line Case with Different Boundary Calculations

The significant pore pressure changes are due to the change in viscosity of water with temperature, and thermal expansion/contraction effects-primarily the pore water as it is heated and cooled. For no-flow boundaries the pore fluid must compress and decompress within the boundaries established as the water expands and contracts. Figure 6 shows bottomhole pressure variations for base-line injection-production cycles over thirty days. For the constant-pressure boundary calculation, cyclic pressures do not change with cycles whereas, for the no-flow boundary, pressure cycles are greater and tend to decrease with cycles.

During the cycles of injection and production, not only does the in situ pore fluid and the heated injected water expand and contract with temperature change, but also the rock expands and contracts. As the rock matrix expands and contracts with temperature change, the formation porosity also changes, generally being reduced with increasing rock matrix expansion. Whether the porosity increases or decreases with rock thermal expansion depends on the insitu stress change-either plane strain with no vertical growth or triaxial stress with horizontal displacements. However, the calculations here did not include such stress change effects. Additionally, the fluid and the rock both can compress slightly, thereby changing volumes with pressure/stresses-this is in addition to the volume changes due to unconstrained thermal expansions/contractions. These effects sometimes may be additive while other times they may counter each other. Thermal effects are complicated and important. Recognizing the low compressibility of the water, pressure effects are experienced at large distances from the well. For example, a no-flow radial boundary calculation with the boundary at three hundred meters radius showed significant pressure effects at the boundary.[9]

2.3 Applications

For real applications, neither boundary condition may be completely correct. For a single well, a constant-pressure radial boundary assumption would seem most appropriate. However, for multiple wells, as is seen in similar petroleum applications, interference can occur where the injection into one well may “push back” against the injection of an adjacent well, and a no-flow boundary may be more appropriate. Such significant effects caused by the boundary assumptions may not normally become apparent in calculations. However, these pressure variations are critical for the application here. Higher injection pressures may lead to incremental hydraulic fracturing, while lower production pressures will require more lifting of the produced fluid and could lead to unacceptable formation fines production. To calculate pressures correctly, the thermal expansion/contractions and the proper boundary conditions must be considered.

2.4 Permeability change

Permeability change with thermal expansion is an additional underappreciated consideration. Conceptually, as the reservoir temperature increases thermal expansion will generally cause the formation permeability to be reduced (under drained conditions). Analyses of thermal expansion/contraction changing permeability have been considered for geothermal systems (for example, thermoelastic increases in fracture permeability with cooling) where reservoir thermal enhancing was considered and for thermal recovery of hydrocarbons. Certainly this can occur, however, for high permeability formations the reduction of formation permeability tends to be insignificant for the application here.[17-19]

2.5 Charging the reservoir

Charging the reservoir by injecting hot water without production is of much interest for the GB concept. A base-line calculation with constant-pressure boundary is shown in Figure 7. In this case injection of 250°C water occurred 8 hours per day for 120 days. Almost no change in injection pressure occurs after ~30 days, and drawdown pressure during production slightly reduces as shown in Figure 7.[19] Thermal profiles were shown earlier, in Figures 1 and 2 before any production had begun.

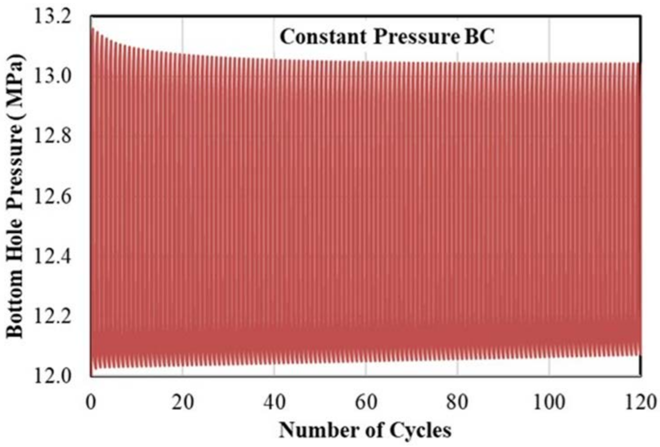

Figure 7 – Hot Water Injection for 120 Days without Production

Thermal charging of the reservoir is important. This can be done when there is solar radiance or when there is excess and unallocated electricity-possibly from excess solar electricity. Thermal charging can create a high-temperature geothermal reservoir using renewable energy.

2.6 Heat recovery

Total heat recovered was considered for different parameter variations after varying numbers of injection-production cycles. Clearly, for certain reservoirs, nearly all of the heat stored can be recovered; this is shown in Figure 8. The figure shows two cases of heat recovery from the produced water, where the produced water temperature is lowered 25°C and 120°C (shown as Tref in the Figure)—in all cases the injected water was 250°C. That is, for high permeability and high porosity reservoirs with low permeability over- and underburden, these calculations show that over ninety percent of the injected heat energy can be practically recovered after a relatively small number of diurnal cycles. This continues to be the primary finding. Additionally, it would appear that the GB will not work for fracture-dominated reservoirs because of low homogeneous reservoir permeability and porosity, based on the calculations here.

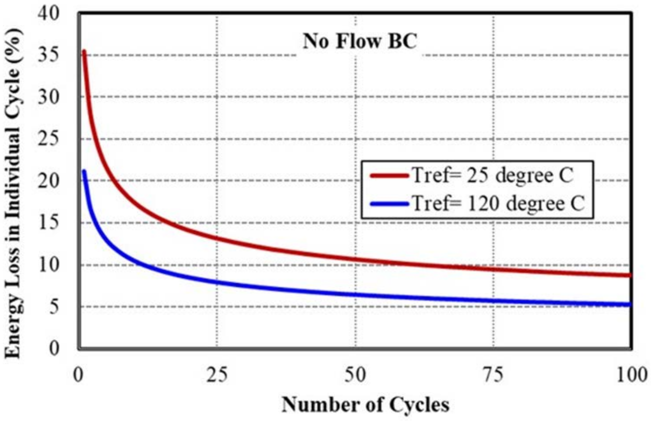

Figure 8 – Heat Loss for Daily Cycles for Base-Line Case

3. Non-Isotropic permeability reservoirs

Calculations were conducted to consider the effects of anisotropic reservoir permeability. A single well injection and production scenario was considered, using the same base-line case as in the previous section, except for variations in the reservoir permeability tensor. A constant-pressure boundary condition was assumed for these calculations. For cases where injection and production are along the entire reservoir vertical height, vertical permeability is not important. For such a case, injection/production is nearly radial flow. This is not the case, however, for injection/production along only part of the vertical well reservoir height. For those cases of partial penetration or partial completion, the problem is either axisymmetric vertical and radial flow or three-dimensional flow if there is also horizontal permeability azimuthal variation.

Calculations were performed for horizontal anisotropic permeability for injection/production into/from a vertical wellbore over the entire vertical reservoir height.[9] Figure 9 shows wellbore temperature for cycling thirty days for a base-line case calculation-except for variation in the horizontal permeability. Horizontal permeability in the "x" horizontal direction is 100 millidarcies and in the "y" horizontal direction is 20 millidarcies. This figure can be compared to Figure 2 for isotropic horizontal permeabilities. The wellbore temperature cycles are nearly the same.

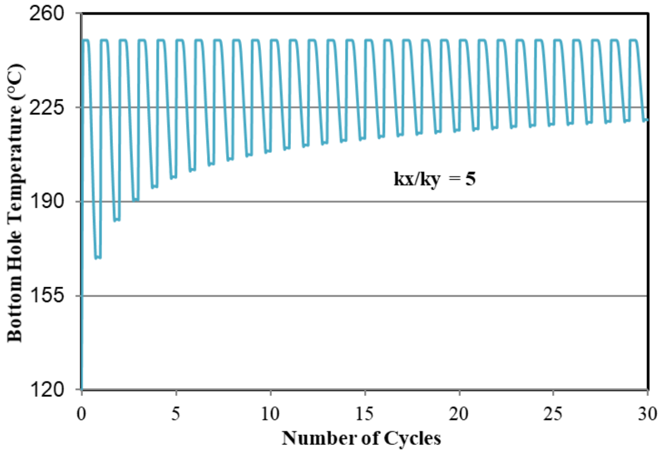

Figure 9 – Wellbore Temperature Cycles for Thirty Daily Cycles

A significant consideration for the GB concept is horizontal temperature profile variations caused by the horizontal anisotropy. Figure 10 shows temperature profiles for the calculation shown in Figure 9, with horizontal "x" and "y" direction permeabilities of 100 and 20 millidarcies respectively.

At five meters from the injection well, the temperature difference between the "x" and "y" horizontal directions is about 50°C after thirty daily cycles of injection and production. This may be important for well layout for any real application.

Wellbore pressure cycles for the same base-line calculation are shown in Figure 11. Again horizontal "x" permeability is 100 millidarcies and horizontal "y" permeability is 20 millidarcies. This figure can be compared to Figure 5 for homogeneous horizontal permeability analog. Pressure cycles are considerably greater than for the 100 millidarcies case (see Figure 5), with injection pressure higher and production pressure lower. Performance for horizontal permeabilities of 100 and 20 millidarcies compares to a homogeneous permeability of about 50 millidarcies shown in Figure 5. It appears that wellbore pressure for horizontal anisotropic permeability is similar to a homogeneous horizontal permeability that is lower than the maximum anisotropic horizontal permeability and higher than the minimum horizontal permeability.

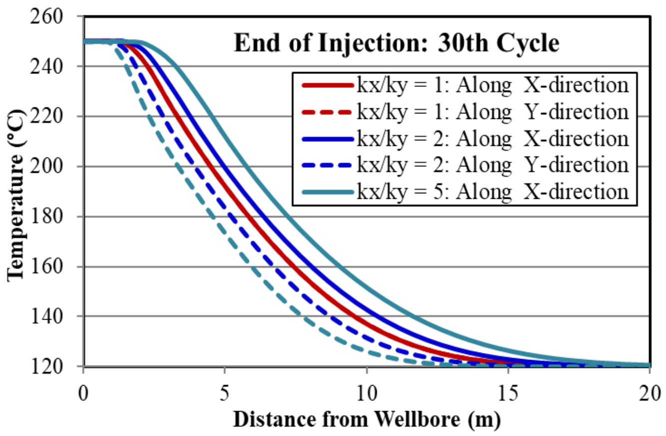

Figure 10 – Temperatures at Distance from the Wellbore

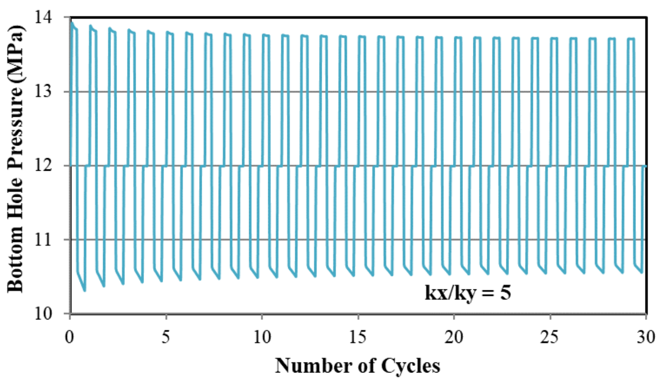

Figure 11 – Wellbore Pressure Cycles for Thirty Daily Cycles

Calculations for more complex formations are in progress,[10] and the results can be non-intuitive. For example, bedded formations with moderate dip will create complicated directional effective permeabilities and require special modeling considerations. Even approximating such reservoir variations requires careful and clever consideration in order to use available computer calculation codes.

4. Well layout and injection-production considerations

Any practical application of the GB concept requires consideration of the entire system. The GB is based on using a formation with high porosity and high permeability as a storage of solar heated water; and, later recovering this hot water for electricity generation or direct heat applications. This will only work economically if injection of the hot water is practical, if the production of cold reservoir water to be heated does not require excessive lifting, and if the hot water stored in the reservoir can be efficiently recovered. These all, at least partially, depend on the reservoir specifics.

The overall system requires reservoir cold-water production, surface heating of the water, and injection of the heated water, all at some time. Additionally, either concurrently or later, the recovery of the hot water from the created geothermal reservoir will occur along with injection of this water when cooled. One possible GB concept would be to design the GB as “Units”, each being a reservoir in itself. Such a system Unit is shown in Figure 12.

4.1 Proposed layout

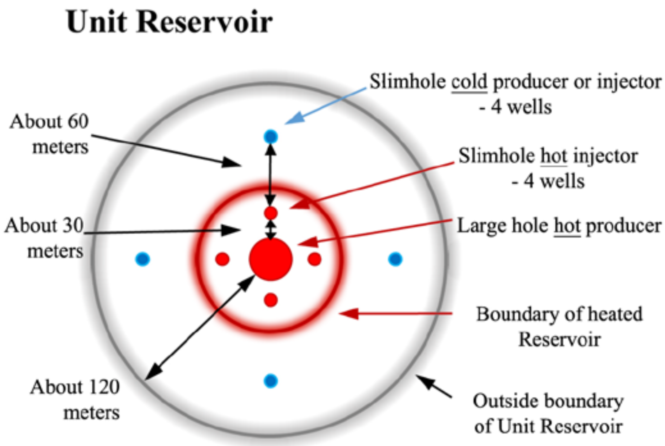

Figure 12 – Plan View of Unit Reservoir Well Layout

Of the nine wells for each “Unit”, eight are slimhole wells and one well is a large-diameter high-flow, hot-water production well. The large production well would not be required to inject and produce hot and cold water-it would only produce hot water. The slimhole hot injector wells would not be required to produce, only to inject. And the slimhole cold wells may produce or inject, but only cold water. The wells are located so as to allow production from an unheated part of the reservoir when cold water is required, while hot water injection and geothermal production is from the hot part of the reservoir. Also, the wells are arranged with the intent of always maintaining water at some pressure to minimize scaling and to prevent exposure to the atmosphere.

With this design, the wells could do the following:

1. When solar radiance is available, cold water from the unheated reservoir would be produced to be heated, and at the same time the heated water would be injected into the hot reservoir. Production of cold water and injection of hot water occur simultaneously, and the slimhole wells would be used.

2. Additionally, if electricity is being produced at this time, hot water production is occurring from the high-flow, hot-water well to supply the binary or flash plant,

a. Some or all of the heated water would be used for generating electricity instead of being directly injected into the hot reservoir,

b. The cooled water from the electricity generation would be reheated, etc., before reinjection,

c. The slimhole wells may be used for injecting hot water or producing cold water depending on the amount of hot water production that is occurring for electricity production in comparison to the amount of total water being heated. Small amounts of water may be produced or injected as a "balance" to manage the difference in density-volumes of hot versus cold water (since no water is to be stored on the surface nor is any new water to be used).

3. If electricity is being produced when there is no solar radiance, hot water production occurs from the large production well and the cold water from the electricity generation is injected into the unheated reservoir.

This combination of wells allows production and injection as would be needed to meet all operational requirements. The slimhole wells completed for only either cold or hot water would significantly lower well costs. In each unit only one large diameter, high-flow, well would produce hot water and would not need to inject cold water, also simplifying its completion and lowering costs.

4.2 Well interference

Additionally, the matter of well interference is critical when considering the layout of the injection-production wells. As an example, for injection to charge the reservoir for 120 days as shown in Figure 4, the "hot reservoir" has radius of about 30 meters for the base-line cases considered here. Any injection wells penetrating the "hot reservoir"—for the illustration considered here—must be within this spacing. However, depending on specific boundary conditions, reservoir pore pressure at a distance of 200 meters from the injection well, after injecting for 120 days, is significantly higher than reservoir far-field pressure as shown in Figure 13. Thus, injection or production wells, even at this distance, from the center of the "hot reservoir" will experience some pressure interference.

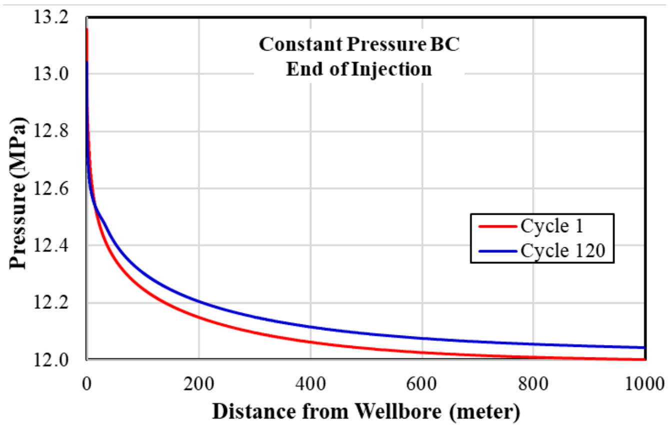

Figure 13 – Reservoir Pressure versus Distance from Injection Well

Consideration of locations of the Units as shown in Figure 12 is important. Furthermore, any intent to create a much larger hot reservoir would have to consider pressure interference. Well planning is further complicated considering the potential of non-isotropic or more complicated reservoir permeability.

5. Geochemistry considerations

The chemical behavior of the produced and injected fluids will be an important consideration in the overall design of the GB system to mitigate wellbore and surface scaling as well as permeability destruction in the reservoir.[20-21] Chemical changes can occur as a result of several different processes. In order to evaluate these chemical effects, data are required on the compositions of the fluid and rock at depth, including the fluid's gas content, and the changes in pressure and temperature that occur as the fluid is cycled between the surface and reservoir.

Mineral deposition or dissolution can occur in response to the separation of gas in the wellbore as the fluid rises to the surface from depths of 1,300-1,500 meters and at pressures of 3.5-4.0 MPa. Also, mineral deposition or dissolution can occur during the injection of hot fluids into cooler reservoir rocks, and during the cooling of the hot water during power production. Under the present production-injection scenarios, it is assumed that: *1)* all of the residual produced liquid after the flashed steam is produced and all of the condensed steam from the power plant will be combined prior to reinjection; *2)* the gas content of the fluid will decrease with time as gases originally in the fluid are removed from the condensed steam on the back side of the turbine; *3)* in the heating cycle the fluid will be heated at the surface to temperatures of 250-300°C before being reinjected; and *4)* the fluid will reach a constant composition after a few injection and production cycles.

As the initial liquid rises in the wellbore, CO2 and other gases will exsolve from the fluid. Calcite scaling is possible during depressurization of the fluid, although trace amounts of other minerals have been identified in wellbore scales.[22-23] The potential for calcite scale will be evaluated, and if necessary, scale inhibitor could be injected into the fluid flows to mitigate carbonate deposition. The effects, however, are expected to decrease with time, as the gas contents decline over a number of cycles.

Because most minerals have prograde solubilities, that is, they become more soluble with increasing temperature, injection of hot fluid into colder rocks can lead to mineral dissolution. Quartz, a common mineral in most rocks, is particularly susceptible to dissolution. Aluminosilicate minerals, including feldspars and clays, may also dissolve but will do so at much lower rates. Rarely, deposition of minerals with retrograde solubilities (sulfates and barite) has been observed as scales in injection wells and the reservoir rocks.[22-23]

Cooling of the hot fluids produced at the surface may lead to deposition of these prograde minerals. In some hot geothermal fields (>250°C) amorphous silica has precipitated in the surface piping and injection wells. Silica deposition is most common in geothermal plants using steam turbines. In these power plants, the combination of silica enrichment due to steam separation and cooling of the fluids before reinjection can lead to precipitation of amorphous silica. The potential for the deposition of amorphous silica must be evaluated, and if necessary, standard mitigation measures can be adopted.

6. Potential formation units within sedimentary basins

Consideration of a GB reservoir where efficient stored heat recovery is possible is dominated by reservoir properties evaluation. The GB concept will only be economically viable for selected geologic locations. In addition to water saturation, high porosity, high permeability formations of adequate thickness and proper depth, the reservoir must be capped with an impermeable layer to prevent hot water migration upward. Formation units within sedimentary basins not in hydrocarbon units, but potentially overlying hydrocarbon formations, are candidates.

Fortunately, sedimentary basins are wide spread throughout the United States. These basins have been investigated over the years as sources for oil, gas, and coal, and thus substantial information exists on the formation characteristics.[24-27] For example, evidence from permeability tests in petroleum systems and groundwater investigations in sedimentary basins shows that permeabilities of prospective reservoir or aquifer units are commonly in the range of 30-100 millidarcies between about one and five kilometers depth as shown in Figure 14.[27]

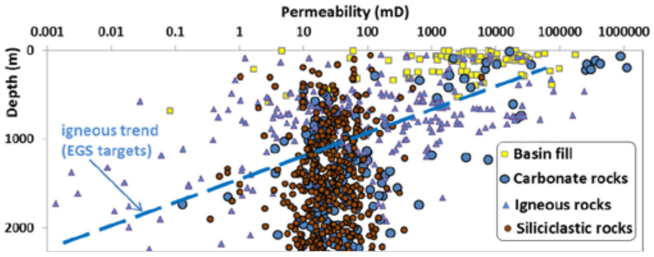

Figure 14 – Sedimentary Basin Units Permeability versus Depth[27]

At less than about 1 km depth, the permeabilities of reservoir or aquifer units decrease from high near-surface permeabilities by orders of magnitude from values of more than 10,000 millidarcies near-surface to values commonly in the range of 10-1000 millidarcies at one-kilometer depth. In contrast to the uniform basin-scale permeability trend for clean sedimentary reservoir units, whether they be siliciclastic or carbonates, the trend for intrusive rocks in this dataset shows a continuing logarithmic decrease in permeability with increasing depth. This is similar to the crustal-scale permeability trend compiled in many studies.[24-25] Figure 14 shows that the requirement for permeabilities of the order of 50-100 millidarcies for the GB should exist in many sedimentary basins.

High permeability units within these basins will tend to have high porosity and water-saturated rock with possibly varying salinity. Additionally, a low permeability cap formation of sufficient thickness is critical to avoid hot water upward migration, and the potential of a steam blowout or explosion. A shale layer overlaying a sandstone formation, for example may be suitable. Equally important will be siting regions away from faults, again to prevent hot water migration out of the created geothermal reservoir.

Candidate reservoirs of high interest may be those located in known areas already considered for hydrocarbon potential, for waste disposal injection locations, or sometimes for geothermal potential.[28] GB potential reservoirs, however, are not considered based on high heat flow, as virgin formation temperature is not critical for the GB. Prospects may be ranked considering the required GB properties, and then evaluated considering the following:

- availability of geoscientific information including previous study reports, potential well(s) information in the area,

- assessment of any available seismic reflection information, wireline log measurements, core data, and outcrop evaluations,

- evaluation of the over- and underlying formations, particularly the overlying formation,

- review of information on pore fluid chemistry, and

- definition of reservoir homogeneity and potential "sweet spots" with optimum properties.

Many potential GB sites are believed to exist, with concurrent opportunities for exploiting high solar radiance, site availability, environmental considerations, and market opportunities. Ultimate commercialization would likely include a field trial, pilot scale demonstration, and then full scale.

7. Geothermal battery energy storage as a system

The GB concept is to allow the storage of renewable solar energy by creating a high temperature geothermal reservoir when solar radiance is available. However, the end product is to be able to recover this stored solar energy for economic value.

To this end, there are different options for using the stored heat,[30] broadly considering applications as shown in Figure 15 taken from the U.S. Department of Energy, "Geo Vision: Harnessing the Heat Beneath our Feet", 2019.[2] The GB concept creates on a local scale, subsurface, high-temperature resource using renewable solar energy.

A first option is that GB may simply expand the potential of geothermal electricity generation beyond the earth's natural thermal gradients as is used today for geothermal energy. Geothermal energy using GB could occur anywhere there is high solar radiance and the proper subsurface reservoir characteristics, irrespective of the subsurfaces' natural thermal gradient. The storage capability would provide for either base load or for varying capacity for any-time load-following electricity generation.

Another option for a GB system may be to use renewable solar radiance to enhance an on-going geothermal electricity generation system,[29] where the proper GB subsurface reservoir may exist. The GB is a storage concept that would allow such enhancement any time, whether or not there is contemporaneous solar radiance. The primary concern for this option would be the existence of a proper formation adjacent to a current geothermal reservoir, possibly as an overlying upper formation. Many geothermal systems do have 'capping formations', often caused by alteration; however, high porosity and high permeability are also required.

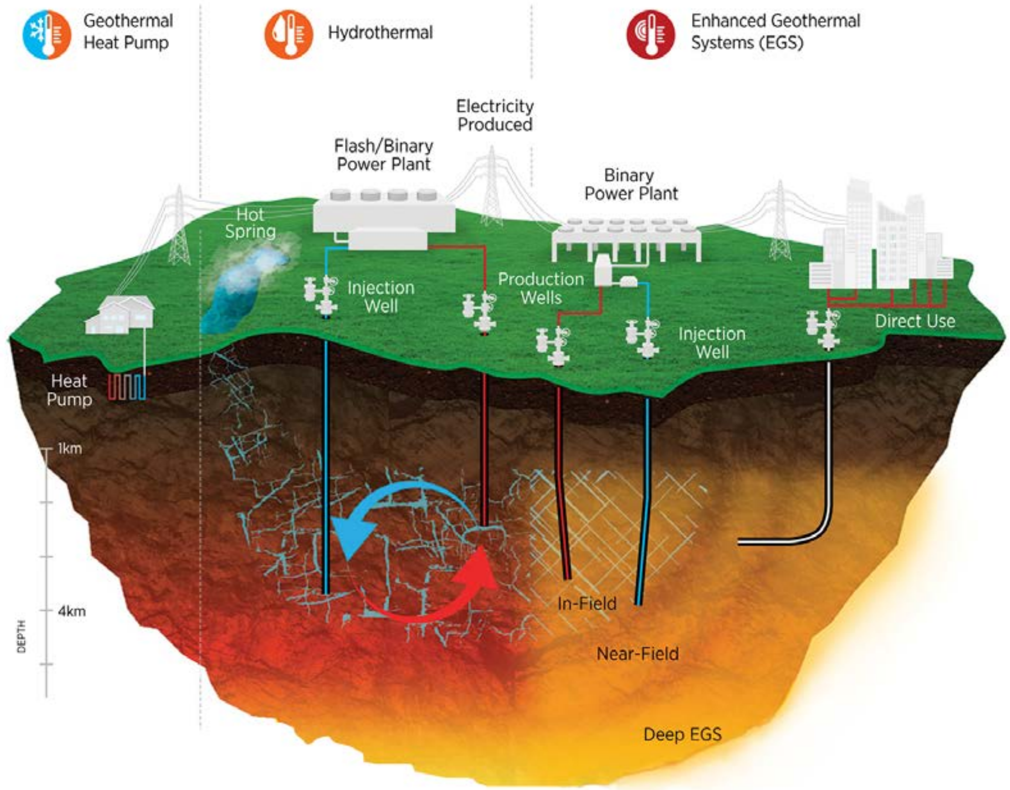

Figure 15 – Options for Geothermal Heat Applications. Taken from Reference [2].

Yet another option, and clearly an attractive opportunity at present, is to draw on the present and vast potential additional solar PV and wind electricity. Unfortunately, this PV electricity often creates excess supply during periods of high solar radiance—such as, afternoons at peak sun or seasonal with high sun in the summer and lower in the winter. Although the efficiency of conversion of PV electricity to heating of water on the surface is low, this is more productive than simply curtailing PV electricity production. This excess PV electricity may be used to charge the GB reservoir for later hot-water production.

There are other potential applications for the GB system. These include direct heat applications for large-scale, high temperature continuous or intermittent requirements.[31-34]

8. Conclusion

The Geothermal Battery Energy Storage ("GB") concept relies on using the earth as a storage container for heat. The concept of the subsurface storing heat is not new. What is new is using a small volume of high porosity and high permeability water saturated rock, away from complex layering and fractures and faulting. The high porosity rock is the storage tank. Water is the media to carry heat from the surface to the storage tank, and then back to the surface when heat is needed. Due to the high pore volume in high porosity rock, the potential storage is huge even for a small volume of rock mass. Likewise, since the natural saturation pore fluid is the water that is used-in a sense over and over again-there is no limit to the water carrying heat. Also, there is no fresh water requirement nor any requirement for disposal of produced water. For a reservoir that is (optimistically) one hundred meters thick with fifteen percent porosity rock, seasonal storage of solar heated water could create a "Unit" high temperature geothermal reservoir with a radius of about 120 meters-which is a remarkably small volume of rock.

Since the GB concept relies on certain critical formation properties, it is essential to understand heat and fluid flow and the geochemical ramifications of what would be a potential GB created high-temperature reservoir. This paper reviews calculations that define critical reservoir parameters that allow success, or create limitations for the concept.

A next step is to use the results here for a direct analysis of a GB system for a specific site with multiple wells and a potential surface operating system. And, in the analysis to account for real site solar radiance and real heat recovery for the given application. For this application, capital and operating costs must be estimated and as assessment of a Levelized Cost of Electricity determined that could allow an estimate of return on investment.

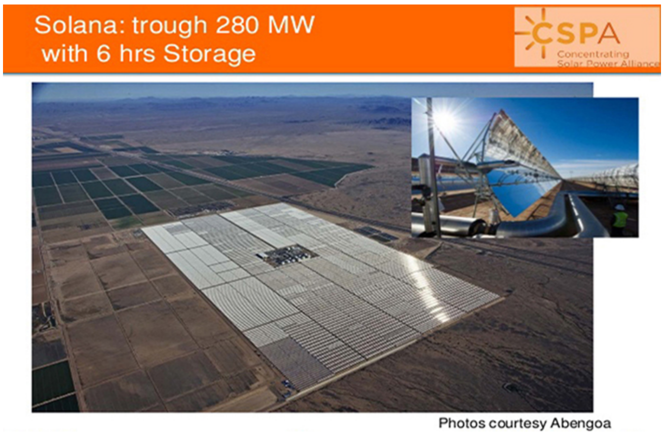

Figure 16 – Operating Solar Collector and Surface Heat Storage System

In considering a GB scheme, it is noted that large solar-thermal heat energy systems already exist, as shown in Figure 16. In the system shown, solar thermal heating is accompanied by storing hot fluids on the surface and later extracting this heat. The figure shows collectors and surface fluid storage for a 280 megawatt rated facility with surface storage for six hours. The scale of the surface storage, unfortunately, does not allow significant "charging" the storage when excess collection capacity is available. Indeed, to have the ability to practically and cost effectively store excess collector capacity for many days of later use would be a great advantage.

An additional benefit of the GB concept is that surface solar heating of the water occurs when there is high solar radiance. Also, solar photovoltaic electricity could power the cold-water lift and the high-temperature injection pumps. This would make pumping fundamentally a "capital cost" as opposed to an "on-going operating cost". Further, at present there is an imbalance of electricity production versus grid demand—generally there is too much electricity when there is high solar radiance electricity. Although not the main focus of the GB, as noted earlier, the GB may use any excess electricity for additional heating of water on the surface, which would reduce the initial scale of the solar heat collectors for a given electricity capacity. More collectors could be added as economics justifies, since the "storage tank" is huge and gradually expands naturally as more heat is added.

A comparison of subsurface storage of heat versus surface storage is also appropriate. Considering the "Unit" reservoir layout as noted earlier and a generic reservoir a 40-meter radius "Unit" 100 meters in height of 20 percent porosity rock—would store about 27 million gallons of water, over 102 thousand cubic meters. A surface tank 40 meters diameter and ten meters high would store about 12,500 cubic meters of heated oil or other liquid. The tank would have to be high quality to accommodate the high temperature and insulated for the storage time required. A heat exchanger and pumping system would be required to heat the pressurized water to the 250°C as used in the analysis here. Each GB "Unit" as illustrated here would be equivalent to 9-10 surface hot-oil tanks, which even with extensive thermal insulation will not be able to provide long-term storage. To reduce the storage tank size, higher specific heat fluid and higher storage temperatures may be used, but both will lead to higher costs, safety issues, and environmental tradeoffs. A "ten GB Units field" would seem very practical, while surface tank heat storage of this scale will be difficult, and impossible for monthly or seasonal energy storage.

Although the "storage tank" and the "water transport media" are large, readily available, and inexpensive, there is only limited energy in a quantity of hot water. Thus to make any heat storage concept economically viable, nearly one-hundred percent of the stored heat must be practically and economically recoverable. Calculations suggest that the GB concept can achieve this.

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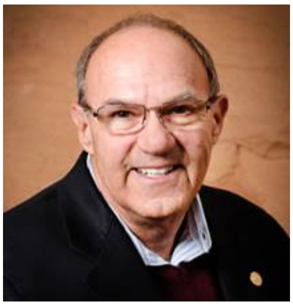

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