

Analysis of Sedimentary Geothermal Systems Using an Analytical Reservoir Model

Chad Augustine

National Renewable Energy Laboratory

Keywords

Sedimentary geothermal, reservoir model, cost analysis, GETEM, doublet

ABSTRACT

An analytic reservoir model of a sedimentary geothermal well doublet system was developed based on the work of Gringarten (1978). This model describes the minimum well spacing and reservoir transmissivity requirements as a function of reservoir lifetime, well flow rate, and well productivity index. The reservoir model assumes flow of fluids with constant properties through homogeneous porous media between an injection and production well doublet. The reservoir model was incorporated into a parametric analysis of the main factors controlling the capital costs of developing sedimentary systems using a modified version of the Geothermal Electricity Technology Evaluation Model (GETEM). Reservoir temperature, depth, well productivity index, and well flow rate were studied. It was found that for a given productivity index, there is an optimum flow rate that minimizes total overnight capital costs, and that this flow rate increases with productivity index. A second scenario showed that optimum flow rates range from just over 100 kg/s for a productivity index of 2 L/s/bar to over 275 kg/s for a productivity index of 30 L/s/bar. The reservoir model can be applied to these results to determine the required reservoir properties, such as well spacing and transmissivity, to realize the proposed cases.

Introduction

A sedimentary geothermal system extracts heat from sedimentary formations. Sedimentary geothermal systems differ from conventional geothermal systems in two fundamental ways. First, heat flow in conventional geothermal systems is convection-dominated, meaning that heat flow in the vertical direction is high due to high vertical permeability so that the temperature profile in the reservoir is nearly constant over a large vertical section. In sedimentary systems, confining horizontal layers such as shale

prevent convective systems from forming, so that heat transfer occurs by conduction through the rock, resulting in temperatures that increase linearly with depth. Second, fluid flow in conventional geothermal systems is typically fracture-dominated, whereas flow in sedimentary geothermal systems is characterized by Darcy flow through a permeable, porous medium. Because of these differences, the evaluation of sedimentary geothermal reservoirs differs from that used for conventional geothermal reservoirs.

The amount of heat that can be extracted from sedimentary geothermal systems depends on the volume of rock contacted by fluid as it travels to a production well and on the amount of fluid that can be produced from the well. Although sedimentary systems can consist of a single well producing fluid from a formation, heat extraction is more efficient in systems consisting of production and injection wells that re-circulate produced fluid through the reservoir (Gringarten, 1978). The flow rate of the production well is governed by the available pressure drawdown in the production well and the transmissivity of the sedimentary formation. This paper evaluates the performance of sedimentary geothermal systems by applying a relatively simple analytic reservoir model to describe heat extraction and pressure-driven flow of a given sedimentary reservoir. The results of this model are used to inform a techno-economic model and analyze the factors controlling the costs of electricity generation from sedimentary geothermal systems.

Analytic Reservoir Model

A simple analytic reservoir model can be used to describe sedimentary reservoir performance. A conceptual sedimentary geothermal reservoir, consisting of an injection and production well doublet in a homogeneous porous media, is considered. The performance of the sedimentary geothermal reservoir can be described by two factors: the production well temperature with time and the pressure difference between the injection and production wells for a given flow rate (which determines pumping requirements). An analytic model that describes these two factors for a well doublet was developed by Gringarten (1978). It is assumed that the sedimentary reservoir is horizontal and of uniform

thickness, and is confined between impermeable layers above and below. The rock and water in the reservoir are at a uniform temperature T_o , and at time $t=0$ the temperature of the injected water is set to T_i . Thermal conduction in the horizontal direction and to the confining layers is ignored, and the temperature is assumed uniform in the vertical direction. Flow is assumed to be steady and single phase¹, and the total well injection rate, Q , is constant and equal to the total production rate. Finally, rock and water properties are assumed to be constant, so that differences between the viscosity of the injected water and the water in the reservoir is neglected. A detailed description of the model development and assumptions for the system is given in (Gringarten and Sauty, 1975).

Using the above assumptions, Gringarten developed an analytic solution for the time for thermal breakthrough to arrive at the production well (i.e., for the temperature of the produced fluid to drop below the initial reservoir temperature, T_o). This time is defined as the lifetime of the well doublet, $Δt$. The time required for thermal breakthrough to occur is (Gringarten, 1978, Eqn. 12):

$$Δt = \left[\phi + (1 - \phi) \frac{\rho_r C_r}{\rho_w C_w} \right] \frac{\pi D^2 h}{3 Q} \quad (1)$$

Where:

D = distance between wells, m

Q = volumetric injection/production well flow rate, m³/s

h = reservoir thickness, m

ϕ = reservoir porosity

$\rho_w C_w$ = water heat capacity, kJ/m³/°C

$\rho_r C_r$ = rock heat capacity, kJ/m³/°C

Gringarten also gives a relationship for the pressure profile in the reservoir in terms of the steady state well drawdown for the production well (Gringarten, 1978, Eqn. 13). The pressure drive between the doublet pair in the reservoir, or the difference between the injection and production well pressure, can be derived using the general theory described in (Muskat, 1937, Section 9.2) to give:

$$\Delta P = \frac{\mu Q}{\pi k h} \ln \left(\frac{D}{r_{well}} \right) \quad (2)$$

Where:

ΔP = pressure difference between injection and production wells, bar

k = reservoir permeability, mD

μ = water viscosity, mD

r_{well} = well radius, m

The same theory, when applied to the difference between the pressure in the production well and the far-field (native) reservoir pressure, gives the identical solution for the production well drawdown described by Gringarten. In fact, the solution is identical for the injection and production well, with the exception of the sign of pressure difference between the well and the reservoir (positive for the injection well, negative for the production well). Using these relationships, the pressure performance of the reservoir can be described in terms of the productivity index, PI , for a given well as:

$$PI = \frac{Q}{\Delta P_{well}} = \frac{2\pi T}{\rho_w g} \left[\ln \frac{D}{r_{well}} \right]^{-1} \quad (3)$$

Where:

ΔP_{well} = pressure difference between well and reservoir, bar

$T = \rho_w g k h / \mu$ = transmissivity of reservoir, m²/s

ρ_w = water density, kg/m³

g = gravitational constant, 9.80665 m/s²

Scaling and Insights

Inspection of the equations describing the analytic sedimentary reservoir model gives some insights into how the reservoir will perform. Eq. (1) shows that the thermal breakthrough time is inversely proportional to the injection/production well flow rate ($\Delta t \sim 1/Q$), directly proportional to the reservoir height ($\Delta t \sim h$), and directly proportional to the square of the well spacing ($\Delta t \sim D^2$). Likewise, the flow rate is directly proportional to the square of the well spacing ($Q \sim D^2$). For a given well spacing, reservoir lifetime can be doubled by halving the flow rate through the reservoir. Doubling the well spacing would quadruple the flow rate the reservoir could support for a given lifetime, or quadruple the reservoir life time for a given flow rate. Conversely, halving the well spacing would require reducing either the flow rate or reservoir lifetime by a factor of four.

The expression in brackets in Eq. (1) has two parts. The first term (ϕ) accounts for the time it would take for a single particle to travel from the injection well to the production well (Grove, Beetem et al., 1970). The second term accounts for the additional time it takes the thermal front to reach the production well due to heating of the injected fluid by the reservoir rock. The ratio of the second term to the first term is called the thermal retardation factor, and describes how the velocity of the temperature front is retarded relative to the fluid velocity through the reservoir (Shook, 2001). Using typical property values for reservoirs and water (see Table 1), the thermal retardation factor have a value of 4, meaning that it takes the thermal front 5 times longer to reach the production well than the time it takes for a particle, such as a tracer, injected at time $t = 0$ to reach the production well. It should be noted that this relationship between the fluid and temperature velocities holds even in non-homogeneous porous media where there are variations in permeability and porosity (Shook, 2001). This correlation could be used to help predict when thermal breakthrough will occur in actual operating systems.

Eq. (1) also shows that reservoir lifetime is independent of the reservoir permeability. Instead, reservoir permeability only impacts the pressure difference across the reservoir, or in other words the pumping power requirements for injecting into and producing from the reservoir, as described by Eq. (2). The pressure difference between the injection and production wells during steady state operation of the reservoir is directly proportional to the flow rate and inversely proportional to both the reservoir permeability and height.

Reservoir Model Results

Numerical values for key reservoir performance variables such as flow rate, well spacing, and lifetime of the well doublet can be

calculated using typical values for reservoir and water properties. Reservoir and water properties used in the calculations are given in Table 1. An initial reservoir temperature of 200°C is assumed.

Table 1. Model parameter values used in illustrative calculations.

Parameter	Value
Porosity, ϕ	0.15
Reservoir thickness, h	50 m
Rock heat capacity, $\rho_r C_r$	2,770 kJ/m ³ °C
Water heat capacity, $\rho_w C_w$	3,860 kJ/m ³ °C
Water viscosity, μ_{avg}	2.18e-4 Pa-s
Well radius, r_{well}	0.108 m (8.5" diam.)
Reservoir lifetime, Δt	30 years

If a reservoir lifetime of 30 years is assumed, then the well spacing requirements for the doublet as a function of well flow rate given by Eq. (1) is shown in Figure 1. For comparison, a typical production well at a commercial hydrothermal power plant has a flow rate of 50-100 kg/s (~1,000-2,000 gpm). Figure 1 shows that the proposed doublet system would require a well spacing of around 1,500 m (~5,000 ft) to achieve these flow rates over a period of 30 years without experiencing thermal breakthrough. The scaling for Eq. (1) discussed above can be used to assess the impact of adjusting model parameters. For example, relaxing the reservoir lifetime requirement from 30 to 20 years for a well producing 150 kg/s would reduce the required well spacing by about 18%, from 2,020 m to 1,650 m.

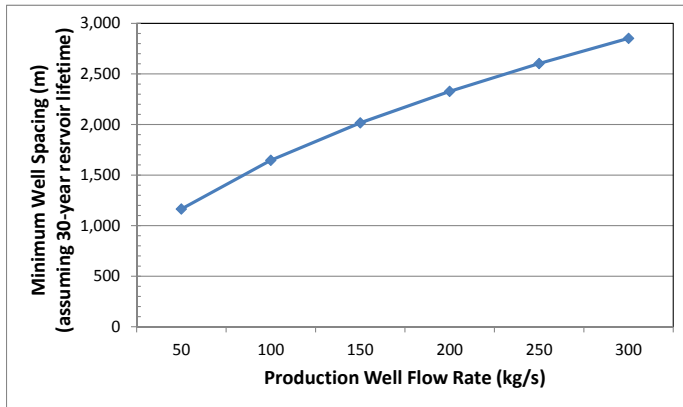


Figure 1. Minimum required well spacing as a function of well flow rate for a well doublet sedimentary geothermal system, assuming a reservoir lifetime (time before thermal breakthrough) of 30 years.

The pressure drive required for the reservoir for a given flow rate can be determined from either Eq. (2) or Eq. (3). The pressure drop in the reservoir is controlled primarily by the transmissivity of the reservoir, or the product of the reservoir thickness and permeability (kh). For a given reservoir lifetime and PI, the required reservoir transmissivity (determined by Eq. (3)) is a weak function of the flow rate. Figure 2 shows the average reservoir transmissivity and kh values required for a reservoir with the model parameters listed in Table 1 and the range of flow rates (and hence well spacings) shown in Figure 1. The figure indicates that high reservoir transmissivities are required to achieve the reservoir performance proposed for the well doublet system. For example, for a doublet system in which each well has a productivity index of

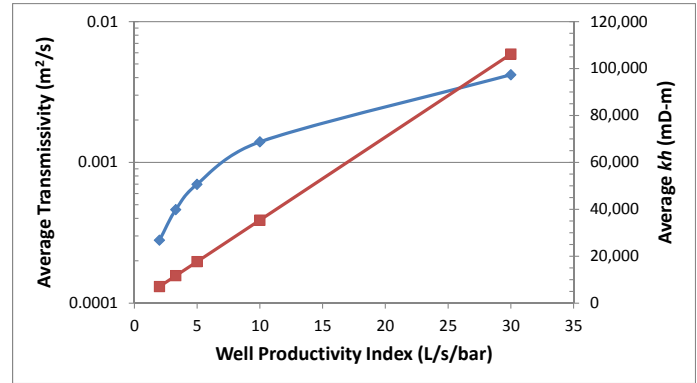


Figure 2. Average reservoir transmissivity and kh values required for a reservoir in a well doublet sedimentary geothermal system, assuming the model parameters listed in Table 1 and the range of flow rates shown in Figure 1.

10 L/s/bar, the reservoir must have a transmissivity of 0.0014 m²/s, or a permeability of ~700 mD for a reservoir thickness of 50 m.

Discussion

The results above indicate that relatively high permeabilities, on the order of hundreds or thousands of millidarcies depending on the reservoir thickness and assumed well PI, are required for well doublet systems with useful lifetimes of multiple decades. The required permeabilities are at the high end of those found in sedimentary formations, especially at the depths where temperatures are typically high enough for electricity generation. For example, a compilation of permeability measurements as a function of depth for the Great Basin and adjoining regions (Figure 3), the majority

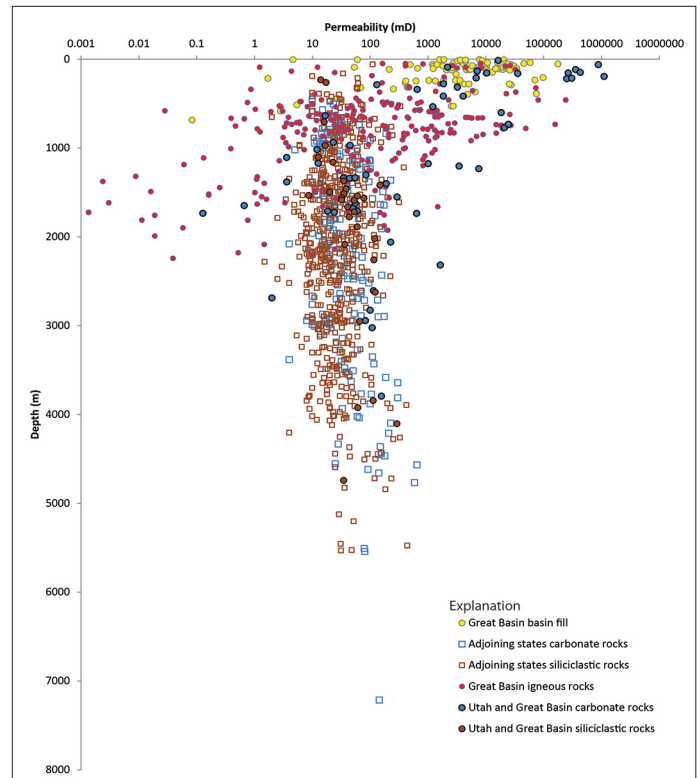


Figure 3. Permeability vs. depth for different rock lithologies in the Great Basin and adjoining regions (from Kirby, 2012).

of which are for siliclastic and carbonate rocks, shows that permeability decreases with increasing depth for all lithologies between 0 and 2,500 m depth, and that for depths greater than 2,500 m, most measurements of permeability for carbonate and siliclastic rocks were between 10 and 100 mD (Kirby, 2012). Similarly, a review of porosity and permeability values for siliclastic and carbonate petroleum reservoirs covering all petroleum-producing countries except Canada (Ehrenberg and Nadeau, 2005) found that both average and maximum porosity tend to decrease with depth (Figure 4). Since lower porosity typically corresponds to lower permeability in porous media (Nelson, 1994), it can be inferred that permeability typically decreases with depth. These trends imply that it may be difficult to find sedimentary formations at depth with sufficient natural permeabilities to support well doublet systems with high production well flow rates and long reservoir lifetimes.

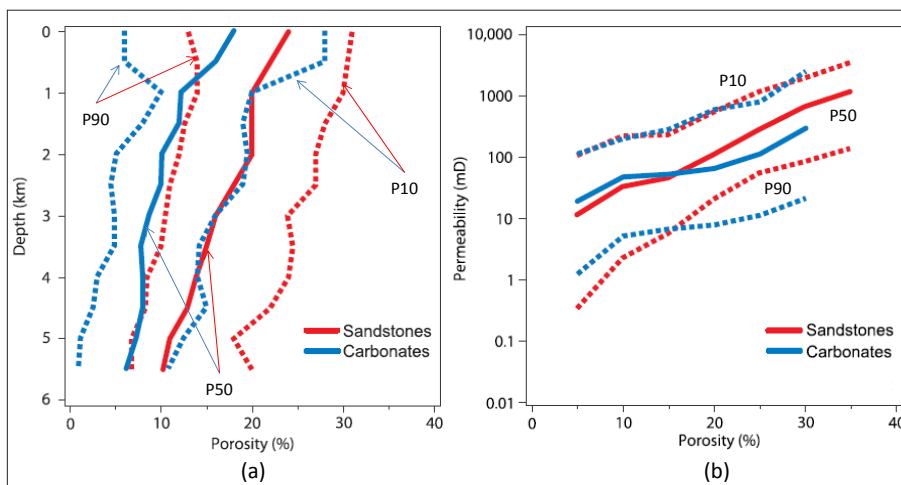


Figure 4. Statistical trends for (a) average porosity vs. formation top depth and (b) average permeability vs. average porosity for global petroleum reservoirs (adapted from Ehrenberg and Nadeau, 2005).

The reservoir model described above assumes a simple doublet well pattern, and makes many simplifying assumptions about the system to arrive at an analytic solution. Previous studies have shown that considering more complex model scenarios can result in better reservoir performance than the model above suggests. For example, Gringarten (1978) showed that the optimum well configuration for a sedimentary geothermal system is a five-spot pattern (Figure 3) with equal well spacing. This configuration has a theoretical reservoir lifetime 50% greater than that for the doublet system described above and a heat recovery factor of 75%.

The current model also assumes that the reservoir lifetime ends at the time of thermal breakthrough. In reality, a surface power plant could accommodate some decline in the production well temperature. A model of the production well temperature decline as a function of time is described by Gringarten and Sauty (1975). Using

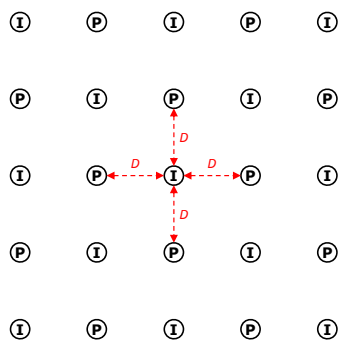


Figure 5. Five-spot well configuration with equal well spacing, D .

the model parameters in Table 1 and assuming a production well flow rate of 100 kg/s, allowing the dimensionless temperature² of the production well to decline by 10% (or 12.5°C, assuming a re-injection temperature of $T_i=75^\circ\text{C}$) over the 30 year lifetime of the reservoir reduces the required well spacing from 1,580 m to 1,260m. Further, the model assumes constant rock and water properties. Accounting for the effect of the difference in fluid viscosity due to the temperature difference between the production and injection well fluid further reduces the required spacing to 1,100 m (Gringarten and Sauty, 1975, Fig. 3). From the viewpoint of flow rate, accounting for some thermal decline and the effect of viscosity differences improves the modeled flow rate that the reservoir with a well spacing of 1,100 m could support from 48 kg/s to 100 kg/s.

None of the models discussed yet account for reservoir heterogeneity, but instead assume the reservoir is a homogeneous porous media. Actual sedimentary reservoirs will have variations in the permeability of the system, fractures, variations in the thickness of the reservoir, etc., that will likely degrade the performance of the reservoir relative to that predicted by models that assume homogeneous porous media. Due to this uncertainty, cost analysis in this paper will continue to use the simple doublet well pattern described in Eq. (1)-(3) as a conservative estimate.

Cost Analysis

The reservoir model described above was incorporated into a parametric analysis of the main factors controlling the costs of sedimentary geothermal systems. An estimate of the capital costs of developing sedimentary systems for electricity generation was carried out using a modified version of the Geothermal Electricity Technology Evaluation Model³ (GETEM). The reservoir model was incorporated into GETEM through the productivity index results (in GETEM, the “Reservoir Hydraulic Drawdown”) and through the production well temperature as a function of time (in GETEM, the “Annual Rate of Temperature Decline”). The capital costs were estimated using GETEM for a range of reservoir temperatures, depths, PI’s, and well flow rates. The PI’s chosen were based on those used in an analysis by (Sanyal and Butler, 2010). Table 2 below shows the parameters and values chosen for parametric analysis.

Table 2. Parameter names and values used in GETEM parametric analysis of costs of sedimentary geothermal systems.

Temp (°C)	Depth (m)	Productivity Index (L/s/bar)	Production Well Flowrate kg/s
190	3,000	2	50
175	4,000	3.3	100
160	5,000	5	150
		10	200
		30	250
			300

The following assumptions were used for all model runs:

- Production from and injection into a single sedimentary formation through well doublets,
- Hydrostatic pressure gradient for reservoir,
- Both injection and production wells are pumped. Injection pump is on surface, while production well uses a down hole pump,
- 30 MW_e-net air-cooled binary geothermal power plant, with plant performance (modeled as brine effectiveness) optimized to minimize total overnight capital costs.

Drilling costs have a significant impact on overall project costs. The default well cost curves in GETEM were used to estimate well costs. These cost curves estimate well costs as a function of well depth. Table 3 shows the casing designs and per-well costs used. It was assumed that the casing designs and well costs were identical for the injection and production well.

Table 3. Casing designs and well costs assumed in GETEM. Cost estimates are on a per-well basis. It was assumed that the injection and production well designs and costs were identical.

Well Designs and Cost Estimates						
	3,000 m		4,000 m		5,000 m	
	(m)	(ft)	(m)	(ft)	(m)	(ft)
Upper Interval	0–1,500	0–4,920	0–2,000	0–6,500	0–2,500	0–8,200
Intermediate Interval	1,500–2,550	4,920–8,350	2,000–3,400	6,500–11,150	2,500–4,250	8,200–13,950
10.63" Open Hole Production Zone	2,550–3,000	8,350–10,000	3,400–4,000	11,150–13,100	4,250–5,000	13,950–16,500
Well Completion Cost	\$7.8M		\$11.9M		\$16.8M	

Binary power plant costs were also estimated using the correlations in GETEM. GETEM estimates binary power plant costs based on the gross power plant size, plant design temperature, and the plant efficiency (described in GETEM as the brine effectiveness). For the runs summarized in Table 2, binary plant capital costs (based on gross power plant output) ranged from \$1,980/kW_e to \$4,760/kW_e. Plant design temperature has the biggest influence on costs, with plant costs decreasing as resource temperature increases. Power plant costs were also seen to increase with resource depth and decrease as PI increased. This is due to the effect of optimizing the plant efficiency (brine effectiveness) to minimize capital costs. As depth increases, well costs (and hence the cost per unit of fluid produced) increase, so the model minimizes costs by building a more efficient plant to squeeze more power out of each unit of produced fluid. Similarly, as PI decreases, parasitic pumping losses increase, so the model again minimizes costs by increasing plant efficiency. Since power plant cost correlation in GETEM (on a \$/kW_e-gross basis) increases non-linearly with plant efficiency, the plant efficiency that minimizes total capital costs pushes power plant costs higher as drilling costs and parasitic pumping losses increase. In extreme cases, such as 5,000 m reservoirs and a production well flow rate of 50 kg/s that require many expensive wells, the

optimum occurs at a the maximum possible plant brine effectiveness, resulting in a high-cost power plant.

Results

Results of the GETEM runs for a sedimentary geothermal system with a reservoir temperature of 175°C and depth of 4 km are shown in Figure 4. The total overnight capital costs are plotted as a function of the production well flow rate for the range of well PI values studied. For each PI, there is a well flow rate that minimizes capital costs. The flow rate at which the minimum occurs increases as PI increases.

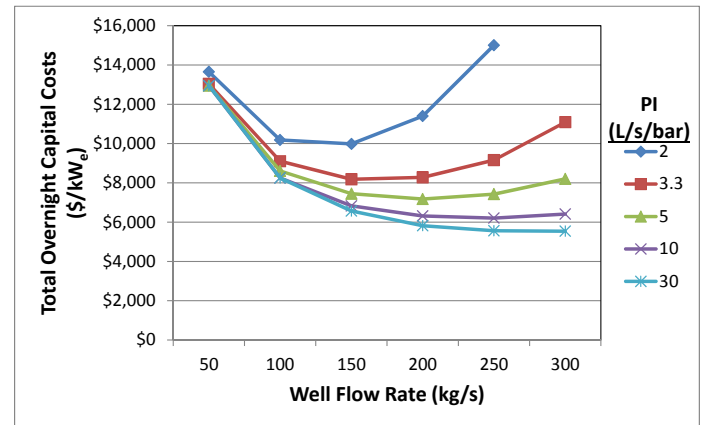


Figure 6. Total overnight capital costs estimated with GETEM as a function of well flow rate and productivity index (PI) for a well doublet sedimentary geothermal system with a reservoir temperature of 175°C and depth of 4 km.

The parametric analysis was run again, but this time the production well flow rate was optimized to minimize project capital costs. This way, the flow rate that minimized capital costs for each well productivity index value could be examined and compared to the reservoir model to determine the required well spacing and reservoir transmissivity. Figure 5 shows the results for all reservoir temperatures, depths, and PI's considered in the study.

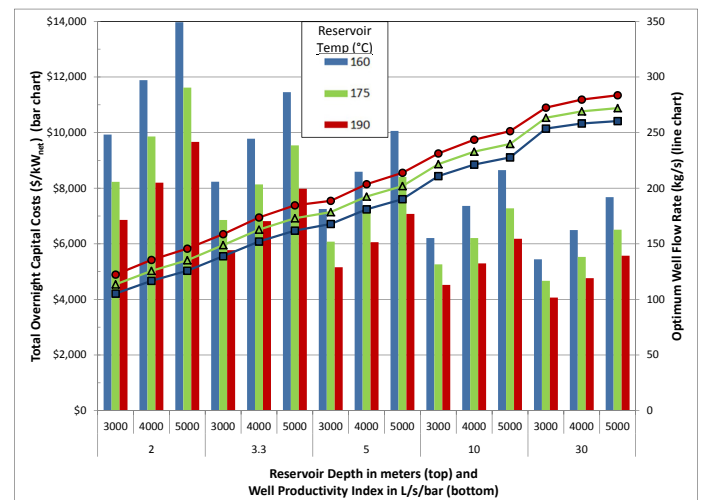


Figure 7. Total overnight capital costs and corresponding optimum well flow rate estimated with GETEM as a function of reservoir temperature, depth and productivity index for well doublet sedimentary geothermal system.

As suggested by Figure 4, the optimum well flow rate increases with PI and reservoir. Figure 5 also shows that the optimum flow rate also increases with temperature. Optimum well flow rates range from just over 100 kg/s for a PI of 2 L/s/bar to over 275 kg/s for a PI of 30 L/s/bar. These optimized flow rates are not constrained by limitations on the size or maximum flow rates of the downhole pumps in the production wells. Comparing the optimum flow rates in Figure 5 with the well spacing results in Figure 1, required well spacing for the optimum flow rates range from about 1,700 m for a reservoir with a PI of 2 L/s/bar to about 2,700 m for a reservoir with a PI of 30 L/s/bar. The minimized capital costs decrease as temperature increases, depth decreases, and PI increases, with the lowest cost cases occurring mostly for cases with PI's of 10 or 30 L/s/bar. Figure 2 can be consulted to determine the required reservoir transmissivity (or reservoir thickness and permeability) for each optimized case.

Another case was run where well production flow rate is limited by conventional pump design. The production well flow rate was limited to 2,500 gpm (145 kg/s), based on guidance in (Sanyal, Morrow et al., 2007). For cases in Figure 7 where the optimum flow rate is less than 145 kg/s, the results were unchanged. For cases where the optimum flow rate was greater than 145 kg/s, capital costs rose in relation to the optimum unrestricted flow rate and the restricted flow rate, with the most extreme case having capital costs increase nearly 30% compared to the unrestricted flow case. Despite this, the restricted flow run still contains 16 cases with capital costs less than \$6,000/kW_e.

Using Figure 1 and Figure 2, a simple reservoir model can be constructed for each of the cases in Figure 5. For example, a sedimentary reservoir with a depth of 3 km, a temperature of 175°C, and a well PI of 5 L/s/bar has estimated capital costs of about \$6,000/kW_e at an optimized well flow rate of about 180 kg/s. This system requires a well spacing of 2,210 m to have a reservoir lifetime of 30 years before thermal breakthrough. Assuming a reservoir thickness of 100 m, a permeability of 175 mD would be required to achieve the indicated PI.

Conclusions

An analytic reservoir model of a sedimentary geothermal well doublet system was developed based on the work of Gringarten (1978)). The model describes the minimum well spacing and reservoir transmissivity requirements as a function of reservoir lifetime, well flow rate, and well productivity index. According to this model, both the reservoir lifetime and well flow rate scale as the square of the well spacing. For reservoirs with life times of 30 years, well flow rates of 50-100 kg/s (1,000-2,000 gpm), typical of commercial hydrothermal power plants, require a well spacing of around 1,500 m. The pressure drive through the reservoir required for a given flow rate is inversely proportional to the reservoir transmissivity. The pressure drop between wells was related to the productivity index to facilitate modeling of sedimentary systems. The model results indicate that relatively high permeabilities, on the order of hundreds or thousands of millidarcies depending on the reservoir thickness and assumed well PI, are required for well doublet systems with useful lifetimes of multiple decades.

The reservoir model was incorporated into a parametric analysis of the main factors controlling the capital costs of developing sedimentary systems using a modified version of the Geothermal Electricity Technology Evaluation Model (GETEM). Reservoir temperature, depth, well productivity index, and well flow rate were studied. It was found that for a given PI, there is an optimum flow rate that minimizes total overnight capital costs, and that this flow rate increases with PI. A second scenario in which capital costs were optimized as a function of well flow rate showed that optimum flow rates range from just over 100 kg/s for a PI of 2 L/s/bar to over 275 kg/s for a PI of 30 L/s/bar. An additional scenario that limited the production well flow rate to 145 kg/s showed that down hole production pump limitations can lead to higher project capital costs compared to the unrestricted flow case. The reservoir model can be applied to these results to determine the required reservoir properties, such as well spacing and transmissivity, to realize the proposed cases.

The reservoir model developed assumes flow of fluids with constant properties through homogeneous porous media between an injection and production well. Considering more complex issues, such as complex well configurations, differences in viscosity or allowing some thermal breakthrough, can actually increase reservoir performance. However, actual reservoirs will not be homogeneous, and reservoir heterogeneities such as variable permeability, sediment layering, flow through existing fractures, variations in reservoir thickness, etc. will likely degrade reservoir performance.

Acknowledgements

This work was supported by the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (EERE), Geothermal Technologies Office (GTO) under Contract No. DE-AC36-08-GO28308 with the National Renewable Energy Laboratory.

Special thanks to Dr. Luis Zerpa and Jae Kyoung Cho of the Colorado School of Mines Petroleum Engineering Department for their collaboration on this project.

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¹ For this study, single-phase flow is assumed throughout the reservoir and wellbores. This is achieved by controlling the well head pressure. The maximum reservoir temperature considered is 190°C, based on its saturated vapor pressure, would require a well head pressure of about 12.5 bar (185 psi) to prevent flashing in the well. Single-phase flow allows the wells to be pumped. If flashing were allowed in the production well, a flash plant would be required and the production well could not be pumped and would be self-flowing, with flow rate controlled by the well head pressure. For the reservoir temperatures considered, binary power plants are typically utilized. See (Sanyal, Morrow et al., 2007) for further discussion.

² Dimensionless temperature is defined as $(T-T_i)/(T_o-T_i)$, where T is temperature at the production well.

³ http://www1.eere.energy.gov/geothermal/geothermal_tools.html

