Geothermal Well Productivity: Why Hotter is Not Always Better

Subir K. Sanyal, James W. Morrow, and Steven J. Butler

GeothermEx, Inc., Richmond, California 94804
e-mail: mw@geothermex.com

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ABSTRACT

This paper investigates the practical range of net power capacity available from conventional and Enhanced Geothermal System ("EGS") wells as a function of temperature. For a geothermal resource temperature up to about 190°C, which is the operating temperature limit of presently available downhole pumps, wells are typically pumped and power is usually generated in a binary-cycle plant, and in rare cases in a flash-cycle or hybrid-cycle plant. In this temperature range under the current state of downhole pump technology, the net MW capacity of a well has a practical upper limit of about 7.3 MW, irrespective of how high the well's productivity index is. This capacity limit cannot be improved unless technology can be improved to allow pumping at a higher rate than the present practical limit of about 160 l/s (2,500 gallons per minute); improving the temperature tolerance of pumps, by itself, will not increase this capacity limit. For resource temperatures greater than 190°C, wells must be self-flowed, and power is generated from such wells in a flash-cycle or hybrid-cycle plant. In the temperature range of 190°C to nearly 220°C a self-flowing well's net power capacity (irrespective of its productivity index) is less than the maximum of 7.3 MW available from a pumped well. Above 220°C, the net power capacity of a well increases rapidly with increasing temperature and productivity index, and the practical upper limit is determined only by well design; the larger the well diameter the higher is the upper limit. The maximum net power capacity available from an EGS well depends on reservoir depth and local temperature gradient, the optimum depth being increasingly shallower for higher temperature gradients. The trend of decrease in the optimum depth with temperature gradient applies whether this optimum is defined in terms of the maximum net MW capacity of a well or the minimum drilling cost per net MW capacity.

Introduction

Above a temperature level of about 250°C, the net power capacity available from a geothermal well is a function of the well's productivity index, reservoir temperature and reservoir steam saturation. There is no reasonable way to generalize what the maximum net power capacity from such a well might be; only actual drilling and testing of the well can confirm its net power capacity. On the other hand, below a temperature of 250°C the reservoir is unlikely to have a significant steam saturation, which allows making certain practical generalizations about a well's maximum net power capacity, as shown in this paper.

A well can be pumped unless the fluid temperature is higher than 190°C (the present limit of operating temperature for commercial downhole pumps, both line-shaft and electrical submersible pumps). Above a temperature of 190°C, a well must be self-flowed. Based on data from numerous geothermal wells worldwide, it is seen that reservoirs with temperatures lower than 190°C contain single-phase water; that is, there is no steam saturation in the reservoir. In fact, steam saturation in the reservoir is extremely unlikely below a temperature of about 220°C. Above 220°C, the pressure drawdown available for pumping decreases rapidly (because of the increasing vapor pressure of water), and the presence of steam saturation in the reservoir becomes more likely, as temperature increases. A well hotter than 220°C cannot be pumped, even if there were no limit to the operating temperature of a pump, because the presence of free steam and gas in the produced fluid would cause cavitation in the pump. Therefore, we have conducted this analysis for three separate regimes of reservoir temperature: 100°C to 190°C; 190°C to 220°C; and 220°C to 250°C. In addition, we present certain generalizations about the net generation capacity and optimum drilling depth of a well in an Enhanced Geothermal System (EGS).

Table 1 summarizes the various possible combinations of well flow mechanisms (pumping or self-flowing) and power cycles (binary, flash or hybrid). Each of the combinations shown in Table 1 has been put into practice somewhere in

Table 1. Combinations of Well Flow Mechanism and Power Cycle in Use.

Power Generation Cycle	Pumped Well	Self-Flowing Well
Binary	x	
Single-Stage Flash		x
Multi-Stage Flash	x	x
Hybrid	x	x
Steam Turbine		x

the U.S. However, for the purposes of this study, we assume the most common combinations of well flow mechanism and power cycle seen today: (a) pumped wells with binary-cycle power generation for the temperature range of 100°C to 190°C, and (b) self-flowing wells with flash-cycle or hybrid-cycle power generation above 190°C. For EGS wells, we have considered a vertical temperature gradient of 50°C/km to 200°C/km, which is the most likely range for potential EGS sites in the U.S.

Analysis Methodology

In a pumped well, the water level must lie above the pump intake to avoid pump cavitation. For any given pump setting depth, the maximum available pressure drawdown (Δp) in a pumped well without the risk of cavitation can be estimated from:

$$\Delta p = p_i - (h-h_p)G - p_{sat} - p_{gas} - p_{suc} - p_{fr} - p_{sm}, \qquad (1)$$

where p_i = initial static reservoir pressure,

h = depth to production zone,

h_p = pump setting depth,

G = hydrostatic pressure gradient at production temperature,

p_{sat} = fluid saturation pressure at production temperature,

p_{gas} = gas partial pressure,

p_{suc} = net positive suction head required by the pump,

p_{fr} = pressure loss due to friction in well between h and h_p, and

p_{sm} = additional safety margin to ensure that cavitation does not occur at pump intake.

The pressure loss due to friction (p_{fr}) in equation (1) can be calculated as follows:

$$p_{fr} = \frac{f \rho v^2}{2 g_c d}\left(h - h_p\right), \qquad (2)$$

where f = Moody friction factor,

v. = fluid velocity in the well,

ρ = fluid density,

d = internal diameter of the wellbore, and

g_c = gravitational unit conversion factor.

The maximum available pressure drawdown can be calculated from equations (1) and (2). The pump can be set as deep as 457 m (1,500 feet) if a line shaft pump is used, but if an electric submersible pump is used, it can be set considerably deeper. However, industry experience with electric submersible pumps is quite limited to date. We have assumed a maximum pump setting depth of 457 m so that either line-shaft or electric submersible pumps can be considered.

From the value of the productivity index (PI) of a well and maximum allowable pressure drawdown, one can calculate the maximum available production rate (W) using:

$$W = (PI)(\Delta p), \qquad (3)$$

Where $$\Delta p = p_i - p. \qquad (4)$$

In equation (4), p_i is initial static pressure in the reservoir and p is flowing bottom hole pressure at the well, which will decline with time if the well is produced at a constant rate W. It should be noted that Δp is more commonly defined as ($\bar{p}$ - p) , where $\bar{p}$ is average static reservoir pressure. Therefore, for a well flowing at a constant rate, p (and consequently PI) declines with time. This decline trend in PI is a function of the hydraulic properties and boundary conditions of the reservoir, and interference effects between wells (if several wells are active simultaneously). For such estimation, it is customary to utilize the so-called Line-Source Solution of the partial differential equation describing transient pressure behavior in a porous medium filled with a single-phase liquid (Earlougher, 1977). This solution gives the production rate (W) from a single well in an infinite system as:

$$W = \frac{2\pi(kh)\rho(\Delta p)}{\mu\, p_D}, \qquad (5)$$

where k = reservoir permeability,

h = net reservoir thickness,

kh = reservoir flow capacity,

ρ = fluid density,

μ = fluid viscosity, and

p_D = a dimensionless variable that is a function of time.

In equation (5), p_D is given by:

$$p_D = -\frac{1}{2} Ei\left(\frac{-r_D^{\,2}}{4t_D}\right), \qquad (6)$$

where t_D = dimensionless time

$$= \frac{(kh)t}{(\phi c_t h)\mu r_w^{\,2}},$$

$\phi c_t h$ = reservoir storage capacity,

ct = total compressibility of rock plus fluid,

ϕ = reservoir porosity,

r_D = dimensionless radius

= r/r_w,

r = distance between the "line source" and the point at which the pressure is being considered (equal to wellbore radius if flowing wellbore pressure is being considered),

rw = wellbore radius, and

t = time.

In equation (6), *Ei* represents the Exponential Integral, defined by

$$Ei(-x) = -\int_{x}^{\infty} \frac{e-u}{u} du \, , \tag{7}$$

Equation (5) is true if the wellbore skin factor is zero, that is, if the wellbore flow efficiency is 100%, the well being neither damaged nor stimulated. If the skin factor is positive (that is, the wellbore is damaged), for the same flow rate *W*, there will be an additional pressure drop given by:

$$\Delta p_{skin} = \frac{W\mu}{2\pi(kh)\rho} \cdot s \, , \tag{8}$$

Productive geothermal wells usually display a negative skin factor, which implies a "stimulated" well (that is, the wellbore flow efficiency is greater than 100%), because such wells intersect open fractures.

The next step is to estimate the net power available from the production rate of *W*. It is possible to estimate the fluid requirement per kilowatt power capacity, or kilowatt capacity equivalent of a given fluid supply rate, from:

Electrical energy per kg of fluid

$$= e \cdot W_{max}, \tag{9}$$

where e = utilization efficiency of the power plant, and

Wmax = maximum thermodynamically available work per kg of fluid.

W_{max} in equation (9) is derived from the First and Second Laws of Thermodynamios:

$$dq = c_p dT, \text{ and} \tag{10}$$

$$dW_{max} = dq(1 - T_o/T), \tag{11}$$

where cp = specific heat of water,

T = resource temperature (absolute), and

T_o = rejection temperature (absolute).

For calculation of power capacity, T_o can be assumed to be the average ambient temperature (assumed to be 15°C). For the most efficient water-cooled binary power plants, a value of 0.45 can be assumed for utilization efficiency. From the above equations, the fluid requirement per MW (gross) generation, not counting the parasitic load of production and injection pumps and power plant auxiliaries, can be estimated. The next step in this analysis is to estimate the fluid production capacity of the pumped wells, from which the parasitic power needed for pumping and the net power capacity at the wellhead could then be calculated.

The power required for pumping must be subtracted from the gross power available from the pumped well. The power required by a pump operating at the maximum allowable drawdown condition is given by:

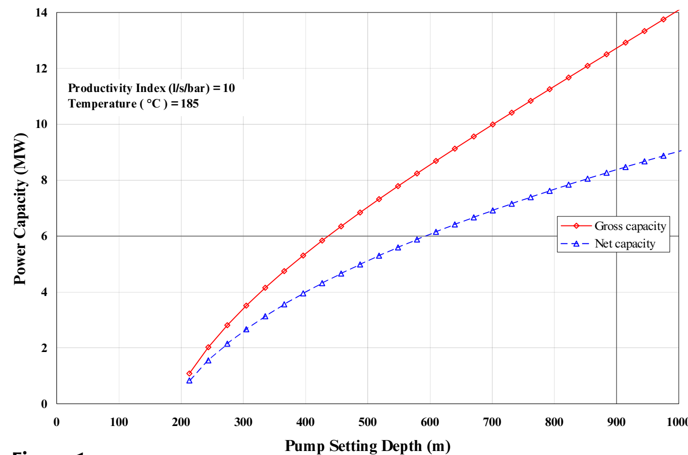

Figure 1.

Table 2. Parameters used for Analysis of Pumped Flow.

Productivity Index:	Variable
Reservoir Temperature:	Depends on well depth
Static Reservoir Pressure:	Hydrostatic
Gas partial pressure:	0
Pump suction pressure:	3.75 bar
Pressure safety margin:	0.68 bar
Relative roughness:	0.018 cm
Casing diameter:	9-5/8 inches
Pump discharge pressure:	7.2 bar (g)
Pump efficiency:	0.75
Motor efficiency:	0.95
Power loss per unit length of pump shaft (assuming electric submersible pump):	0
Rejection temperature:	21° C
Utilization factor:	0.45

$$\text{Pumping power} = (W.H/Ep + hpL)/Em, \tag{12}$$

where H = total delivered head,

L = shaft horsepower loss per unit length,

E_p = pump efficiency, and

E_m = motor efficiency.

In equation (12), H is given by:

$$H = (p_d - p_{sat} - p_{gas} - p_{sm})/G + h_p, \tag{13}$$

where p_d = pump discharge pressure.

Figure 1 shows an example of calculated initial gross and net power capacities of a 3,800 m deep well, with a productivity index of 10 l/s/bar, as a function of pump setting depth. Table 2 lists the various parameters we have used in this exercise.

We have also considered self-flowing wells tapping a reservoir at a temperature of 190°C or more. This flow behavior analysis has been conducted by numerical wellbore simulation based on the estimated PI of the well; Table 3 summarizes the important assumptions. Numerical wellbore simulation allows the estimation of wellhead power capacity versus flowing wellhead pressure, taking into account the hydrostatic, frictional and acceleration pressure gradients, wellbore heat loss, phase change, steam separation pressure and steam required by the power plant per MW. Figure 2 is an example of the calculated "deliverability curve" of a 2,743m (9,000 ft) deep self-flowing well for a range of productivity index values. Figure 2 presents the simulated wellhead pressure as a function of the total flow rate; using the assumptions in Table 3, the net MW capacity for various PI values can be derived from their respective deliverability curves.

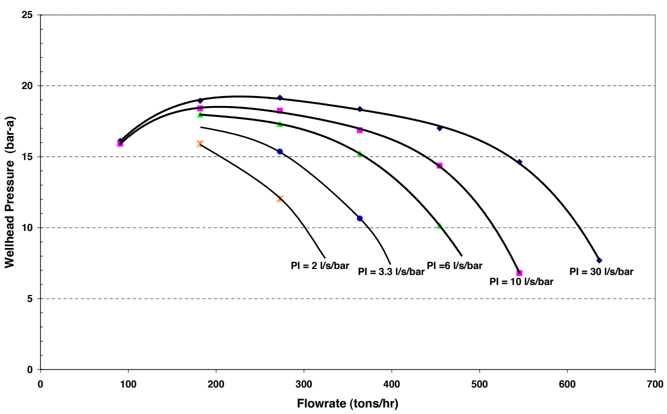

Figure 2.

Table 3. Parameters used for Analysis of Self-Flowing Wells.

Well depth:	Variable
Well casing diameter below the pump:	9-5/8 inches
Well casing diameter above the pump intake:	13 3/8 inches
Reservoir temperature:	Variable
Static reservoir pressure:	Hydrostatic
Gas content in water:	nil
Relative roughness of casing wall:	0.018 cm
Steam separation pressure:	4.46 bar (g)
Steam requirement per MW generation:	2.27 kg/s

Data from commercial geothermal wells show a wide range in PI, from about 1 l/s/bar for marginally sub-commercial wells to as high as 40 l/s/bar for exceptionally prolific wells; a good geothermal production well typically shows a PI on the order of 10 l/s/bar. It is also seen that the flow capacity (that is, permeability-thickness product) of a commercial well generally lies in the range of 1 to 100 Darcy-meter (D-m) and geothermal wells typically display a small, negative skin factor. To decide on the appropriate range of PI values to be used in this study, we calculated the PI for these estimated ranges of flow capacity and a skin factor range of 0 to -1. Figure 3 shows the calculated PI versus time for various flow capacity and skin factors values considered. Based on Figure 3, we chose 2 to 30 l/s/bar as the broadest realistic range of PI for commercial wells producing from a 100°C to 250°C reservoir.

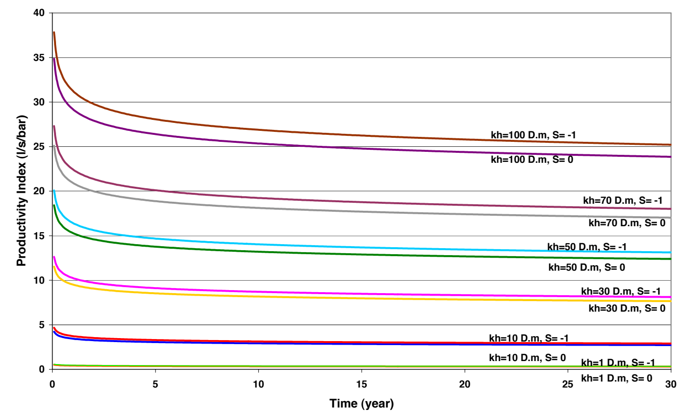

Figure 3.

Results for Pumped Wells

Figure 1 shows an example of the calculated gross and net power capacities versus pump-setting depth for a pumped well with a PI of 10 l/s/bar and producing from a 185°C reservoir. The vertical separation between the gross and net MW capacity curves in Figure 1 represents the parasitic power consumed. This figure shows that with increased pump setting depth, the gross and net capacities increase slowly, but the parasitic load increases rapidly. Given the practical limit of 457m (1,500 feet) in pump-setting depth today, this well has net a generation capacity of 6.3 MW.

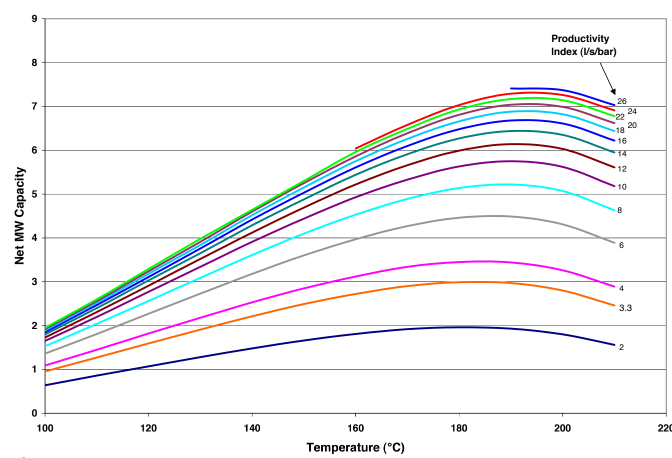

Figure 4.

Figure 4 presents the calculated net power capacity of a pumped well versus temperature for a range of PI values. This figure shows that for any PI value, net power capacity of the well increases monotonically with temperature until it reaches a maximum at a temperature level of 190°C to 200°C, depending on the well's PI. After reaching this maximum, the net capacity of the well declines with increasing temperature. This decline in net capacity with temperature reflects the decline in the maximum available drawdown, which, in turn, is caused by the increasing vapor pressure with temperature.

Figure 4 shows that little gain in net well capacity can be achieved by raising the operating temperature limit of commercial pumps beyond 190°C. On the other hand, Figure 1 indicates that increasing the maximum possible pump-setting depth beyond 457m and the maximum possible pumping rate beyond 160 l/s (2,500 gallons per minute) will increase the net power capacity available from a well. Figure 4 shows that irrespective of how high the PI is, a pumped well today cannot deliver significantly more than about 7.3 MW(net). It should be noted that this maximum capacity was estimated assuming a zero gas saturation in the produced water. The higher the dissolved gas saturation in water the lower will be the available drawdown; this will reduce the maximum net power capacity of a pumped well.

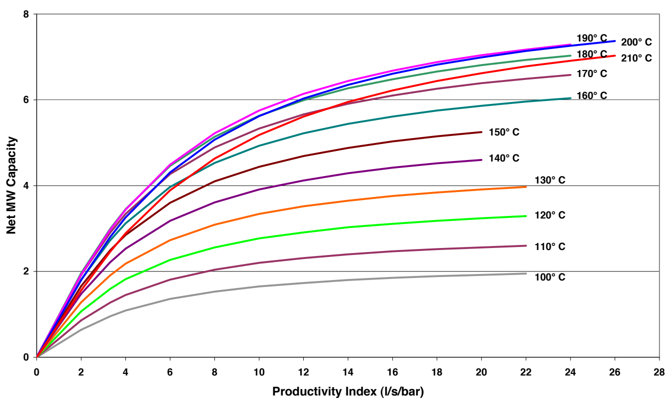

Figure 5.

Figure 5 presents the same results in terms of the net power capacity versus PI for various temperatures. This figure shows that for any temperature level, the net capacity is very sensitive to PI when PI is low; for prolific wells, the net capacity is not too sensitive to PI. Furthermore, Figure 5 confirms that for all PI values, the net capacity peaks in the 190°C to 200°C range.

Results for Self-Flowing Wells

Figure 2 presents the calculated "deliverability curves" of a self-flowing well with a range of PI values producing from a 244°C reservoir. This figure shows the wellhead pressure versus

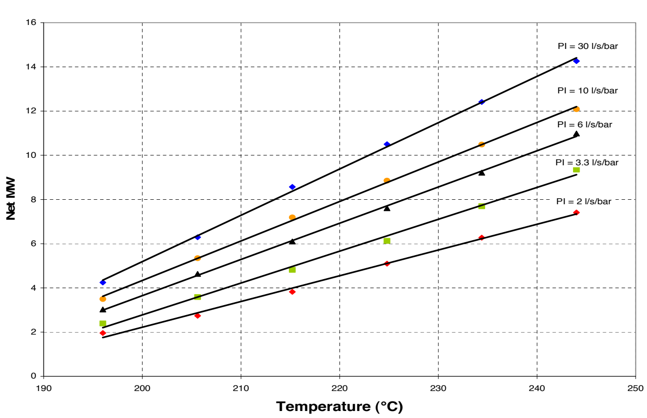

Figure 6.

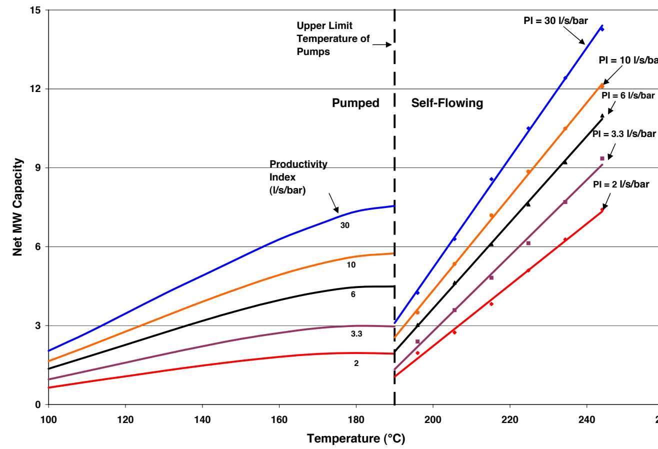

Figure 7.

total production rate (steam plus water) from the well. From this figure, we can estimate the net MW capacity of the well for various pi values given an assumed steam separation pressure and steam requirement per MW (Table 3). Similar calculations were conducted for various temperature and PI values.

Figure 6 presents the calculated net power capacity versus temperature of a self-flowing well for various PI values. This figure shows that unlike the case of pumped wells, there is no upper limit in net MW capacity of a self-flowing well, which is a nearly linear function of temperature, the slope of this linear trend increasing slightly with increasing PI. Figure 7 is a composite of the results for pumped and self-flowing wells. This figure shows that between 190°c and 220°c, a self-flowing well has less power capacity than the maximum net capacity of a pumped well with the same PI.

If a net power capacity higher than 7.3 MW is sought, either the pumping rate should be greater than 2,500 gpm or the reservoir temperature must be greater than about 220°C; for exceptionally prolific wells, this "break point" may be as low as 210°C. In other words, if the reservoir temperature is less than 220°C, the maximum available net power capacity of a geothermal well is 7.3 MW whether the well is pumped or self-flowed and irrespective of how high its PI is. The only way this barrier in net capacity can be breached is by increasing the maximum pumping rate possible from a pump and making it practically feasible to deepen pump setting beyond 457m (1,500 feet). However, for self-flowing wells, there appears to be no way to increase the maximum level of net capacity beyond this 7.3 MW limit unless reservoir temperature is greater than about 220°C.

Results for EGS Wells

In an Enhanced Geothermal System (EGS), the reservoir is created by hydraulic stimulation of low permeability rock. Unlike hydrothermal projects, where the reservoir already exists at a certain depth, an EGS project allows significant flexibility in choosing the depth range within which to create a reservoir, provided that the depth range has suitable geologic formations and appropriate *in situ* stress conditions. Since temperature increases with depth and there is flexibility as to depth, the question arises: should the wells for an EGS project be the

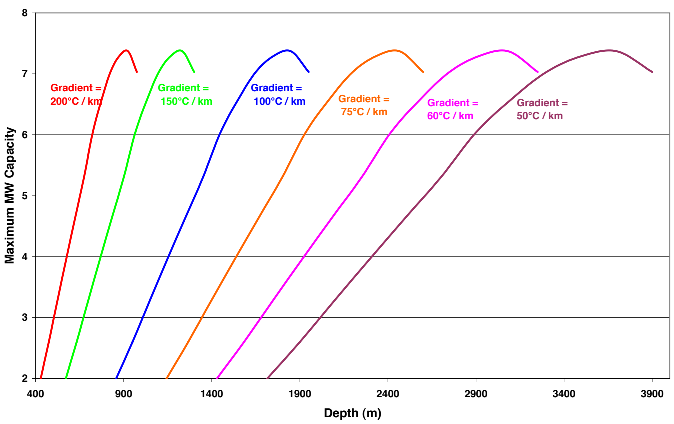

Figure 8.

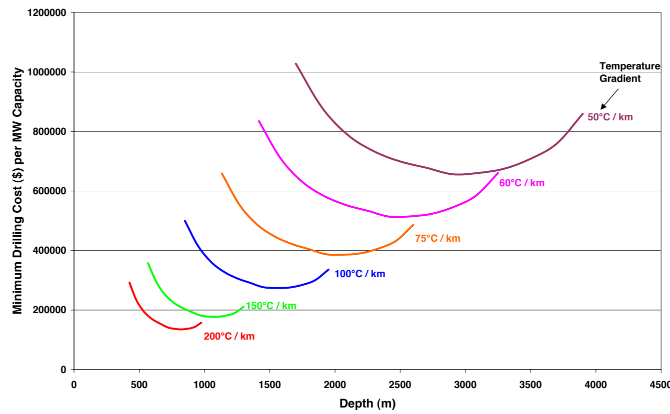

Figure 10.

deepest possible, or is there a practically optimum depth? This issue is considered below.

The temperature versus depth at an EGS site is dictated by the local vertical temperature gradient, which ranges from 50°C/km to 200°C/km at potential EGS sites in the U.S. Assuming pumped wells, we have calculated the maximum net power capacity versus depth for various temperature gradient values; Figure 8 presents the results. This figure shows that for any temperature gradient, the maximum net capacity increases nearly linearly with depth until it reaches a maximum; thereafter the capacity decreases with depth. The depth at which this maximum net capacity is reached becomes shallower as temperature gradient increases. Let us now review the commercial consequences of the observations from Figure 8.

Figure 9 shows an empirical correlation of the cost of drilling a geothermal well versus well depth; the cost has been escalated from 2003 dollars (presented in GeothermEx, 2004) to 2004 dollars according to the U.S. Producer Price Index for drilling. The correlation in Figure 9 is also similar to that of MIT (2006), which considered 2004 dollars. From Figures 8 and 9, we have estimated the trend in the minimum drilling cost per net MW capacity achievable from an EGS well versus its depth and for a range of temperature gradients (Figure 10). This figure shows that for any temperature gradient, drilling cost per net MW well capacity goes through a minimum at a certain depth, which would be the optimum depth for a commercial EGS project, assuming that appropriate *in situ* stress conditions and suitable rock formations are present at that depth.

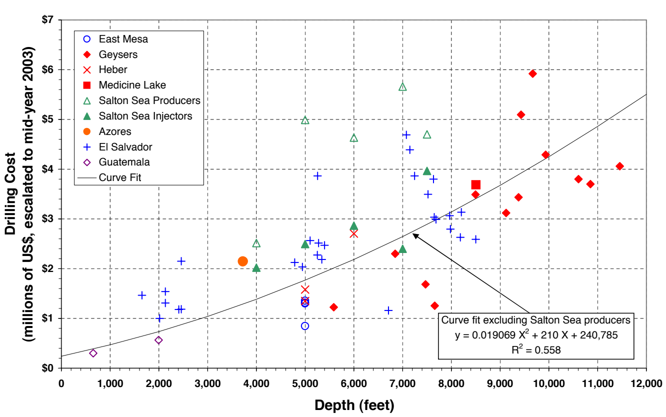

Figure 9.

Figure 11 presents the optimum depth for an EGS project versus the local temperature gradient; one plot in this figure considers the maximum net MW capacity of a well as the optimization criterion, and the other plot considers the minimum drilling cost per net MW as the optimization criterion. It should be noted that Figure 11 is based on pumped wells. However, the results apply equally for self-flowing wells up to a reservoir temperature of nearly 220°C, because the maximum net power from a self-flowing well does not exceed that of a pumped well of the same PI for temperatures less than about 220°C (Figure 7).

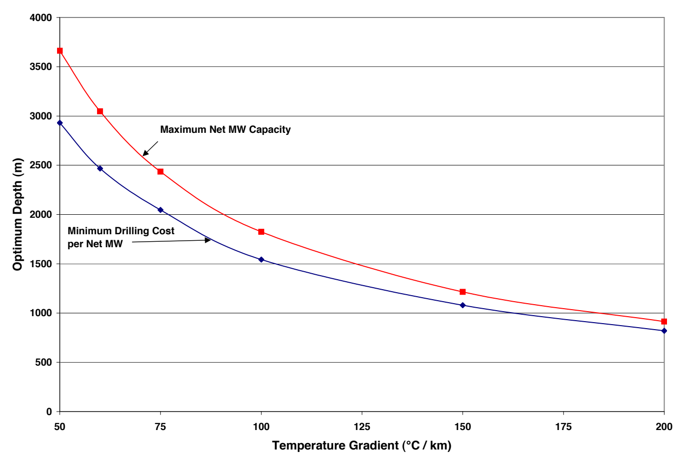

Figure 11.

Conclusions

1. The net power available from a pumped geothermal well reaches a maximum of 7.3 MW at a temperature level of 190° to 200°C under the current state of downhole pump technology. This maximum capacity assumes a negligible dissolved gas content and the most efficient binary power conversion possible today; if there is dissolved gas or the plant efficiency is lower, this limit of net capacity will be lower than 7.3 MW.

2. The maximum operating temperature of commercial geothermal pumps today is 190°C; any improvement in the

operating temperature limit of downhole pumps without increasing the pumping rate limit will not increase net power capacity. If it becomes practical for downhole pumps to be set deeper and have higher pumping rates than practicable now, the maximum net capacity would be higher.

3. Over the temperature range of 190°C to 220°C, wells need to be self-flowed; between 190°C to nearly 220°C, a self-flowing well will not exceed the maximum net capacity of 7.3 MW available from a pumped well.

4. Whether a well is pumped or self-flowed, and whatever its productivity index, the maximum net capacity of a geothermal well cannot exceed 7.3 MW up to a temperature level of nearly 220°C.

5. There is no obvious limit to the net power capacity of a geothermal well producing from a reservoir above 220°C; reservoir temperature and reservoir steam saturation along with the well's mechanical design and productivity index are the determining factors. The larger the effective wellbore diameter the higher is the upper limit of net power capacity of such wells.

6. The maximum net power capacity available from an EGS well depends on reservoir depth and local temperature gradient, the optimum depth being increasingly shallower for higher temperature gradients.

7. The trend of decrease in the optimum depth for EGS wells with temperature gradient applies whether this optimum is defined in terms of the maximum net MW capacity of a well or the minimum drilling cost per net MW capacity.

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