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# Optimization of Power Generation from Moderate Temperature Geothermal Systems – A Case History

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## ABSTRACT

Advances in binary-cycle power and submersible pump technologies over the past two decades have made electric power generation from geothermal fields in the moderate temperature range (100° to 180°C) convincingly commercial. For geothermal water in this temperature range, binary-cycle is more efficient for power conversion than flash-cycle and pumping of wells is more efficient than self flowing. The lower temperature limit of 100°C is imposed by the limits of binary-cycle technology and the upper limit of 180°C is imposed by the limits of pump technology commercially available today. This paper is a case study of optimization of net power generation from such a field at Raft River, in the State of Idaho, United States.

The optimization of net generation must consider the following intertwined issues: (a) individual well productivity characteristics as controlled by near-wellbore reservoir properties, (b) maximum pumping rate possible from a well given the present state of submersible pump technology, (c) well productivity decline with time due to a combination of reservoir pressure decline and interference between wells, (d) maximum gross power available per unit water production rate given the present state of binary cycle technology, and (e) parasitic power needed for both production and injection pumps. The well productivity issue is represented by the well's productivity index as estimated from reservoir transmissivity and wellbore flow efficiency (skin factor). The change in the well's productivity index with time is computed from the solution of the partial differential equation describing transient pressure behavior in a porous medium. The effect of well interference on productivity index is taken into account by superposition of the solution in space. The well pumping issue is taken into account by estimating the pumping rate for the maximum available drawdown, which is a function of the pump characteristics and setting depth, reservoir temperature and pressure, production depth, gas content in the water, and the frictional pressure loss in the well. The parasitic power required for pumping is subtracted from the gross power available from the produced fluid to arrive at the maximum net wellhead power available from a well within realistic limits of pump-setting depth (914m) and pumping rate (220 liters per second).

The proposed approach is applied to planning for development at Raft River, where 5 existing wells are planned to be worked-over for production. The maximum net wellhead power capacity available from 3 of the existing wells is shown to be 10 MW (net). For a 17 MW (net) development scenario using 5 production wells, the alternatives of maintaining power capacity by (a) make-up well drilling, (b) deepening of pump setting with time, and (c) combination of both, are examined.

## 1. INTRODUCTION

The moderate-temperature (140° to 146°C) geothermal field at Raft River, in the State of Idaho, United States was extensively explored and drilled during the 1970s. Locations of the existing wells are shown on Figure 1. Total depths of the production wells, which are mainly vertical, are 1,520 to 1,980m. By the early 1980s, production and injection wells had been tested many times and an experimental 5 MW binary power plant was installed and operated briefly to demonstrate the feasibility of power generation at Raft River. But the project was abandoned because of two major technological barriers at that time to commercial power production from this resource:

- The wells were too cool to allow self-flowing for routine production, but downhole geothermal pump technology had not become routine by the early 1980s.
- The resource was too cool for flash-cycle power plants, which were the only plants commercially available at that time. Therefore, an experimental binary-cycle demonstration power plant was used at Raft River, with disappointing results.

Fortunately, both downhole pump technology and binary power generation are no longer technological barriers; and are routinely used today in commercial power projects. The field is now being developed for commercial power generation.

The existing wells have been idle for nearly 20 years, and may have suffered cement or casing damage, hole sloughing and accumulation of rock debris, scaling, corrosion, etc. Furthermore, undocumented mechanical junk have been left behind in some wells. The potential for such problems is increased by the fact that the wells at Raft River are artesian, and have leaked and/or been tapped for production by farmers. Since the wells have had some production and the local irrigation wells have been extensively used for two decades, it is possible that wellhead pressures and productivity may have changed since the last testing two decades ago, even if there has been no change in mechanical well condition. Therefore the mechanical condition downhole and current production capacities of the wells needed to be determined; these investigations and field testing have recently been concluded.

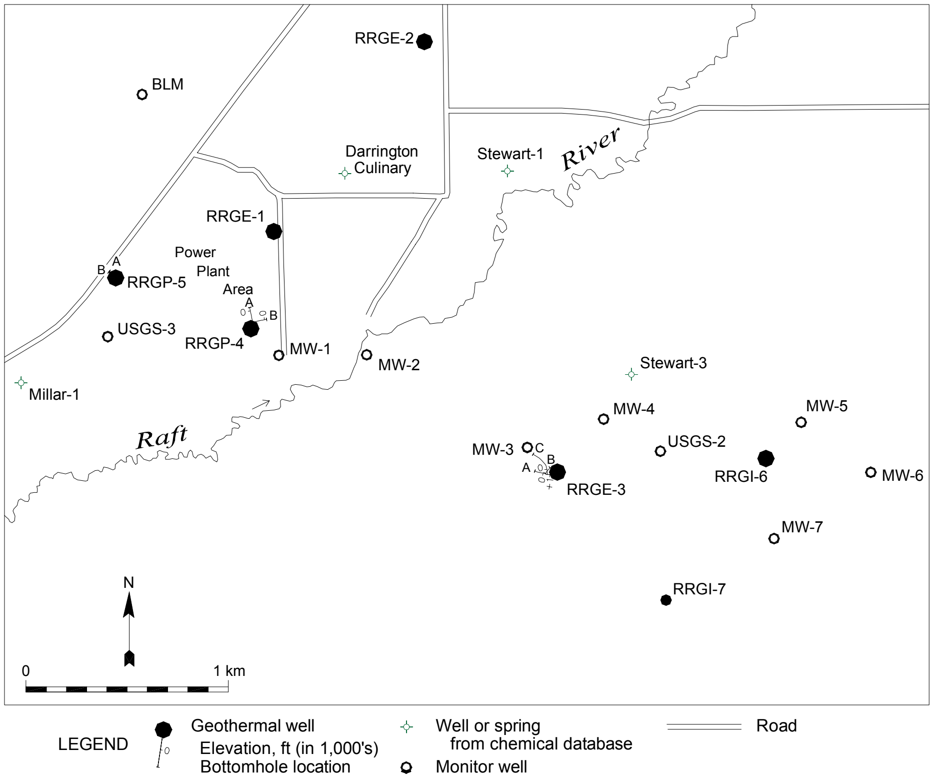


**Figure 1: Well location map, Raft River geothermal field**

The new development planning had been based on available data on reservoir properties rather than individual well properties, for the new well testing program was expected to change the latter but not the former.

A review of the old well test results lead to the following conclusions relevant to well productivity considerations presented below: (a) temperature of the produced fluid is in the 140° to 146°C range, (b) transmissivity of the reservoir is in the approximate range of 6.1 to 61.0 darcy-m, (c) storage capacity is on the order of 0.44 to 0.004 m/bar; and (d) wells typically show an artesian head of about 10.32 bar-g. Therefore, for this analysis, fluid temperature was assumed to lie between 140° to 146°C, reservoir transmissivity was conservatively assumed to be 15.2 darcy-m, storage capacity was assigned a mid-range value of 0.044 m/bar, and an artesian head of 10.3 bar-g was assumed. Preliminary analysis of the results from recent field testing have confirmed the reasonableness of the above assumptions.

## 2. POWER AVAILABLE FROM THE FLUID

It is possible to estimate the fluid requirement per kilowatt generation capacity, or kilowatt capacity available from a given fluid supply rate, from:

$$\text{Electrical energy per unit mass of fluid} = e \cdot W_{max}, \quad (1)$$

where is utilization efficiency of the power plant, and $W_{max}$ is maximum thermodynamically available work per unit mass of fluid.

W in equation (1) can be derived from the First and Second Laws of Thermodynamics:

$$dq = c_p dt \quad (2)$$

$$dW_{max} = dq(1-T_o/T) \quad (3)$$

where $c_p$ is specific heat of water, T is resource temperature (absolute), and $T_o$ is rejection temperature (absolute).

For calculation of power capacity, $T_o$ was assumed to be 15.6°C, which is average ambient temperature at Raft River. For power generation from a resource at this temperature range, binary-cycle technology must be used; for modern binary power plants, a maximum value of 0.45 can be assumed for utilization efficiency. If the plant is water-cooled, with a cooling water temperature of 15.6°C, the calculated capacities are reasonable. If the plant is air-cooled, $T_o$ will be higher than assumed in the summer and lower in the winter; however, the average ambient temperature should still not be far from 15.6°C. Therefore, the annual average plant capacity should be similar to that calculated irrespective of the type of cooling technology utilized.

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, was estimated to be 27.1 liter/second (l/s) for 140°C fluid and 25.2 l/s for 146°C fluid. Therefore, the next step in this analysis was to estimate the fluid production capacity of the wells, from which the parasitic power needed for pumping and the net power capacity at the wellhead could then be calculated.

## 3. WELL PRODUCTIVITY ISSUES

The productive capacity of a geothermal well can be quantified by a Productivity Index (PI), which is defined here as the mass flow rate (w) per unit pressure drawdown $(\Delta p)$, that is,

$$PI = w / \Delta p \, . \tag{4}$$

In the above definition $(\Delta p)$ is represented here as:

$$\Delta p = p_i - p \, , \tag{5}$$

where $p_i$ is initial static pressure in the reservoir and p is flowing bottom hole pressure at the well, which declines with time as the well is produced. Therefore, p, and consequently PI, of a well flowing at a constant rate declines with time. This decline trend in PI is a function of the hydraulic properties and boundary conditions of the reservoir, production rate (w), and interference effects between wells (if more than one well is active). For such estimation one can utilize the so-called Line-Source Solution (Earlougher, 1977) of the partial differential equation describing transient pressure behavior in a porous medium filled with a single-phase fluid. This solution gives the production rate from a single well in an infinite system as:

$$w = \frac{2\pi(kh)\rho(\Delta p)}{\mu \, p_D} \, , \tag{6}$$

where k is reservoir permeability, h is reservoir thickness, $\rho$ is fluid density, $\mu$ is fluid viscosity, and $p_D$ is a dimensionless variable that depends on the boundary conditions and is a function of time.

In equation (6), $p_D$ is given by:

$$p_D = -\frac{1}{2} Ei\left( \frac{-\phi c_t \, \mu \, r_w^{\,2}}{4kt} \right) , \tag{7}$$

where $C_t$ is total compressibility of rock plus fluid, $\varphi$ is reservoir porosity, $r_w$ is wellbore radius, and t is time.

In equation (7), Ei represents the Exponential Integral, defined by

$$Ei(-x) = -\int_x^{\infty} \frac{e-u}{u} du \tag{8}$$

Equation (6) is true if the wellbore skin factor (*S*) is zero, that is, 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 (Earlougher, 1977):

$$\Delta p_{skin} = \frac{w\mu}{2\pi(kh)\rho} \cdot S \tag{9}$$

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 typically intersect open fractures. For the purposes of this analysis, both a conservative assumption of zero, as well as a more optimistic assumption of –1, were made for the value of the skin factor.

From equations (4) through (9) it is clear that the PI of a well, as defined here, is independent of production rate, and can be calculated as a function of time. The PI of a well declines with time, but the decline rate lessens continuously, and after a few months of flow the PI levels off substantially. If more than one well produce from the same reservoir, there will be interference between the wells, reducing the PIs of all wells. From equations (4) through (9) one can calculate the pressure drawdown at a well, and therefore its PI, in response to both its own production and the interference effect of simultaneous production from other wells in the field; this is accomplished by superposition in space of the Line-Source Solution. Similarly, superimposition in time of the Line-Source Solution can be used to calculate the pressure drawdown and PI when the flow rate changes with time.

In addition to flow-rate, skin factor, and diameter of the production well whose PI is being considered, the calculation requires the distance to and flow rate from each neighboring active well and estimates of several reservoir parameters. These required reservoir parameters are: viscosity and specific volume of the reservoir fluid, reservoir flow capacity (transmissivity), reservoir storage capacity (storativity) and initial reservoir pressure. Specific volume and viscosity of pure water were used for calculation since the reservoir water at Raft River has a low salinity and low gas concentration. Since the wells at Raft River show an artesian head, the initial static reservoir pressure was represented as:

$$p_i = h \cdot G + p_{art} \tag{10}$$

where h is depth to the production zone, G is hydrostatic gradient at the fluid temperature and $p_{art}$ is artesian head (10.3 bar-g).

Since the reservoir temperature at Raft River varies within the range of 140° to 146°C, PI calculations were done for both temperature levels. Figure 2 shows the calculated values of PI of well RRGE-1 (Figure 1) as a function of time over an assumed 20 year project life (for a reservoir temperature of 140°C and a skin factor value of zero). Figure 2 shows five calculated curves, the upper most of which represents the calculated PI of well RRGE-1 flowing by itself with all other wells in the field inactive. Figure 2 shows four other calculated PI curves for well RRGE-1 assuming (1) both RRGE-1 and RRGP-4 are flowing, (2) RRGE-1, RRGP-4 and RRGP-5 are flowing, (3) RRGE-1, RRGP-4, RRGP-5 and RRGE-2 are flowing, and (4) RRGE-1, RRGP-4, RRGP-5, RRGE-2 and RRGE-3 are flowing. Similar calculations of PI values versus time for well RRGE-1 were made for a reservoir temperature of 140°C and a skin factor value of -1, and for a reservoir temperature 146°C with skin factor values of –1 as well as zero. To be conservative, well RRGE-1 was chosen for PI calculations because this well would suffer most from interference among the five wells due to the fact that this well is the one most surrounded by the other wells (Figure 1). The calculations here ignore any potentially beneficial effect of pressure support, or any potential adverse effect of cooling, due to injection; these issues will be handled later through numerical modeling after reworking and re-testing of the wells, and by adopting an appropriate field management strategy.

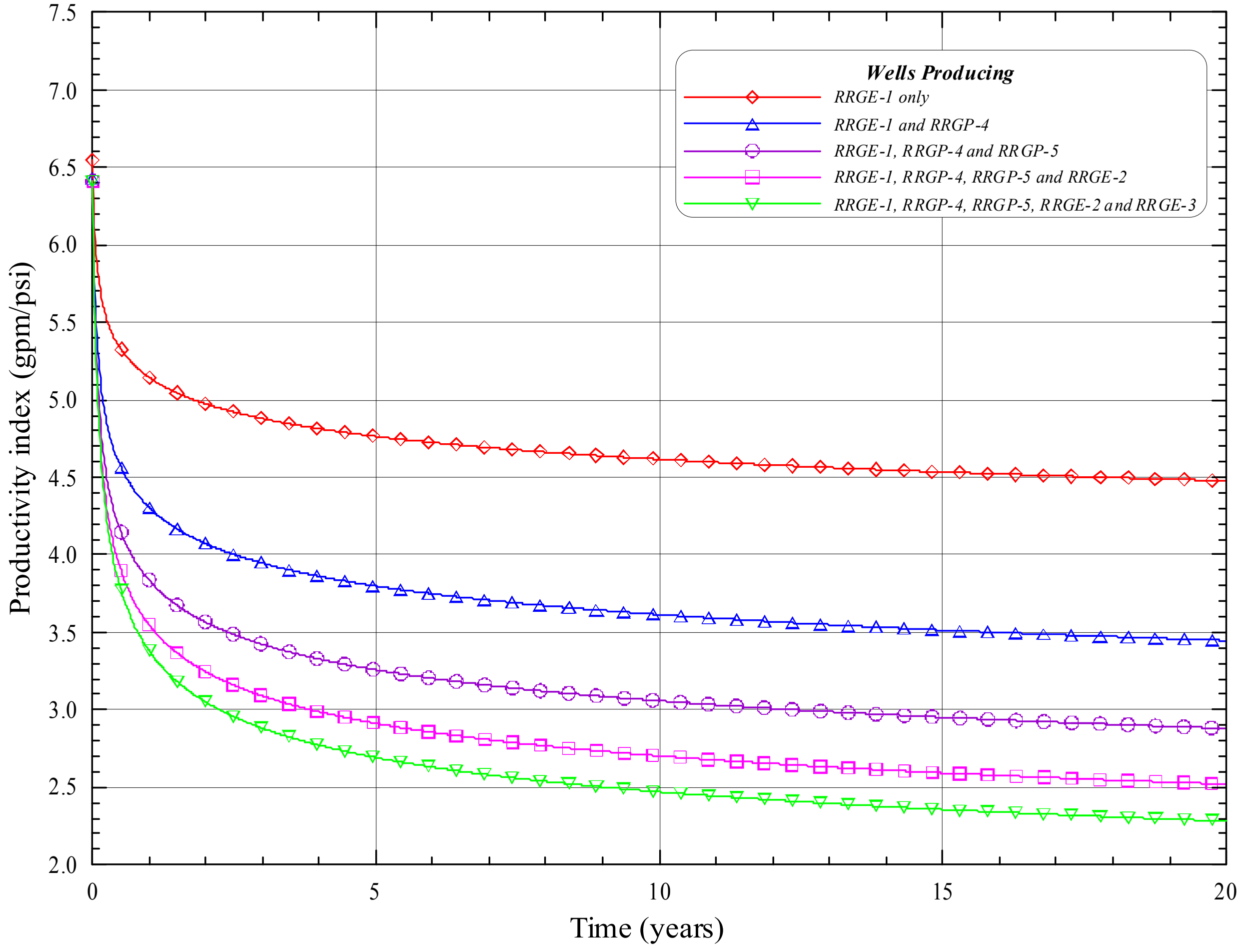


**Figure 2: Effect of well interference on productivity**

While Figure 2 shows calculated PI values for well RRGE-1, one needs to estimate also the maximum available pressure drawdown ($\Delta p$) at this well before its maximum production rate can be calculated. Since the wells at Raft River can be pumped, the next step in the analysis is to estimate the maximum available drawdown for pumping of these wells and the parasitic load of this pumping. The next section therefore considers the intertwined issues of well pumping, parasitic load and net generation.

## 4. WELL PUMPING AND RELATED ISSUES

In a pumped well, the water level must lie above the pump intake; otherwise the pump will cavitate. For any given pump setting depth, the maximum available pressure drawdown ($\Delta p$) in a pumped well without the risk of cavitation can be estimated from:

$$\Delta p = p_i - (h-h_p)G - p_{sat} - p_{gas} - p_{suc} - p_{fr} - p_{sm}, \quad (11)$$

where $p_i$ is initial static reservoir pressure, h is depth to production zone, $h_p$ is pump setting depth, G is hydrostatic gradient at production temperature, $p_{sat}$ is liquid saturation pressure at production temperature, $p_{gas}$ is gas partial pressure, $p_{suc}$ is net positive suction head required by the pump, $p_{fr}$ is pressure loss due to friction in the well between h and $h_p$, and $p_{sm}$ is additional safety margin to ensure cavitation does not occur at the pump intake.

Pressure loss due to friction ($p_{fr}$) in equation (11) can be calculated from:

$$p_{fr} = \frac{f\rho v^2}{2g_c d}(h - h_p), \quad (12)$$

where v is fluid velocity in the well, $\rho$ is fluid density, d is internal diameter of the wellbore, $g_c$ is gravitational unit conversion factor and f is Moody friction factor (calculated from relative roughness and internal diameter of the pipe, and Reynolds Number).

The maximum available pressure drawdown can be derived from equations (11) and (12).

The pump can be set as deep as 472m if a line-shaft pump is used, but if an electric submersible pump is used it can be set considerably deeper. The values of $p_{suc}$ and $p_{sm}$ were assumed to be 2.1 bar and 0.7 bar, respectively, which are typical for pumped wells. The remaining parameters in equations (11) and (12) can be estimated from the fluid characteristics. Since the Raft River resource has a very low gas content, $p_{gas}$ was neglected. From the calculated value of PI of a well and maximum allowable pressure drawdown, one can calculate, as a function of time, the maximum available production rate (w) given by:

$$w = (PI) \cdot (\Delta p), \quad (13)$$

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

$$\text{Pumping power} = (w.H/E_p + h_p.L)/E_m, \quad (14)$$

where H is total delivered head, L is shaft power loss per unit length, $E_p$ is pump efficiency, and $E_m$ is motor efficiency.

In equation (14), H is given by:

$$H = (p_d - p_{sat} - p_{gas} - p_{suc} - p_{sm})/G + h_p, \quad (15)$$

where $p_d$ is pump discharge pressure.

For the purposes of these calculations, the following typical values were assumed:

L = 0.056 kW per m, $E_p = 0.75$, $E_m = 0.95$, and $p_d = 13.8$ bar-a.

For calculation of the total available power capacity, two scenarios were considered: (a) a 3-well scenario with wells RRGE-1, RRGP-4 and RRGP-5 flowing, and (b) a 5-well scenario with wells RRGE-1, RRGP-4, RRGP-5, RRGE-2 and RRGE-3 flowing. As shown below, the 3-well scenario allows generation of 10 MW (net), while the 5-well scenario can deliver a 17 MW (net) capacity.

Figure 3 shows the calculated total gross power capacity and net power capacity (after deducting the power needed by the pump) as a function of pump setting depth in well RRGE-1 under the 3-well scenario, assuming a resource temperature of 140°C and a skin factor of zero. The separation between the gross and net power capacity curves in Figure 3 shows, for any given pump setting depth, the amount of parasitic power consumed by the pump. The curves in Figure 3 were calculated conservatively based on the final PI of the well at the end of the 20-year project (for a 140°C fluid and a skin factor of zero); Figure 2 shows this final PI value to be 2.64 l/s/bar, which was used to generate Figure 3. Figure 3 shows that the net power capacity of the well increases, but this rate of increase slows down, with increasing pump setting depth. This fact plus the fact that the deeper the pump setting the higher the operating cost of the pump, imposes a practical limit to increasing the net production capacity of a well by deepening of the pump setting. For conventional line-shaft pumps, the maximum setting depth is about 460m. For such a pump, Figure 3 shows the net power capacity of RRGE-1 to be as high as 3.7 MW under the 3-well scenario (for a resource temperature of 140°C and a skin factor of zero). With an electric submersible pump, the net power capacity will be even higher subject to a practical limit imposed by cost and pumping efficiency considerations and the maximum flow rate capacity of commercially available submersible pumps. For the purposes of this analysis, a pump setting depth of 914m and a pumping rate of 220 l/s are taken as practical limits. Gross and net power capacities of well RRGE-1 versus pump setting depth for the 3-well scenario were similarly calculated for a skin factor of -1, and for a temperature of 146°C with skin factor values of zero as well as –1.

Figure 4 shows the gross and net power capacities versus pump setting depth for well RRGE-1 under the 5-well scenario, for a fluid temperature of 140°C, the skin factor being zero. Figure 4 when compared to Figure 3 shows the reduction in net power capacity per well when 5 wells are produced simultaneously compared to 3 wells. It should be noted that Figures 3 and 4 present the net power available from a well as a function of pump setting depth for a given PI. However, PI declines with time (see, for example, Figure 2); therefore, the net power available would decline with time for any given pump setting depth. This issue is considered next.

## 5. GENERATION SCENARIOS CONSIDERED FOR RAFT RIVER

We have assumed that of the 5 existing production wells at least 3 can be worked over and restored to full capacity. However, it is possible that all 5 wells could be restored to full production, or one or two new wells could be drilled, so that up to 5 production wells would become available. Using equations (1) through (15), one can calculate the net total MW capacity available from a group of wells as a function of both pump setting depth and time elapsed from the start of production.

Figure 5 shows the total net MW capacity from all 3 flowing wells (under the 3-well scenario), as a function of pump setting depth for a range of time elapsed from the start of production; this figure assumes a resource temperature of 140°C and a skin factor of zero. Figure 5 shows that the net power capacity declines with time but increases with the pump setting depth. A 10 MW (net) capacity power plant will require at least 20% more capacity, that is, 12 MW (net), at the wellhead to supply the parasitic load of injection pumps and other auxiliaries. From Figure 5 it is seen that for a 10 MW (net) generation from the power plant, equivalent to a 12 MW (net) generation at the wellhead, the minimum pump setting depth must be 192m initially, 337m after 6 months, and so on. Even after 20 years, the pump setting depth need not be more than 550m, which is clearly within the limit for setting electric submersible pumps. As regards injection, production from the 3 wells can be disposed of in the two existing injection wells and/or two unused production wells. Therefore, it is unlikely that any new injection well will need to be drilled. Therefore, we conclude that a 10 MW (net) power plant capacity can be supported if only 3 of the 5 existing wells can be worked over and restored to their full productivity and if sufficient injectivity can be secured from the existing injectors and/or unused producers.

Finally, if all 5 existing wells flow, a higher plant capacity should be supportable. Let us only consider the most conservative case (resource temperature of 140°C and a skin factor of zero). Figure 6 shows that for a pump setting depth of 610m, which is moderate for an electric submersible pump, the net wellhead MW capacity per well declines from 9.3 initially to 3.4 in 20 years. Assuming a parasitic load of 20% for injection pumping and other auxiliaries, 5 wells can thus deliver 37 MW initially to 13.6 after 20 years with a fixed pump setting depth of 610m. Therefore, as well capacity declines with time, to maintain a given plant capacity either the pump could be periodically re-set deeper in the well or make-up wells could be drilled. It may be unreasonable to assume resetting pumps or drilling make-up wells within the first few months after generation starts; therefore, for the purposes of this study, the net generation capacity available from the wells after 6 months of production will be considered as the effective initial capacity.

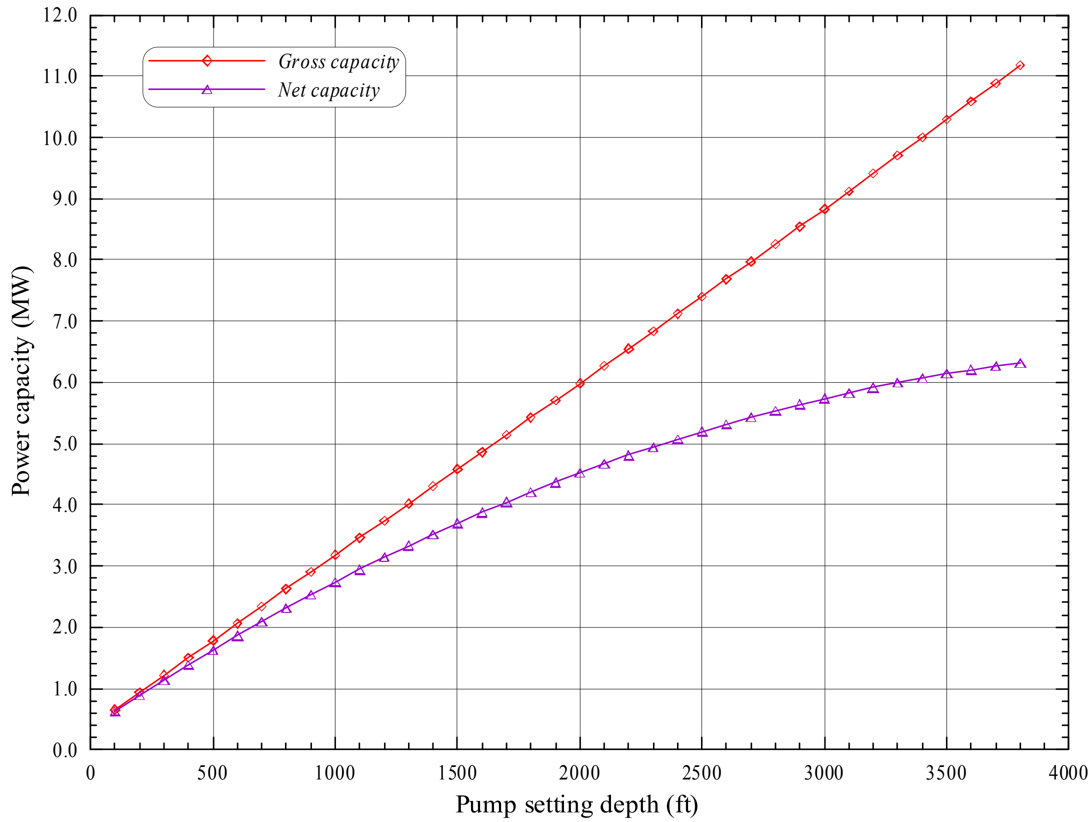


**Figure 3: Power capacity available from well RRGE-1 vs. pump setting depth for 3-well scenario**

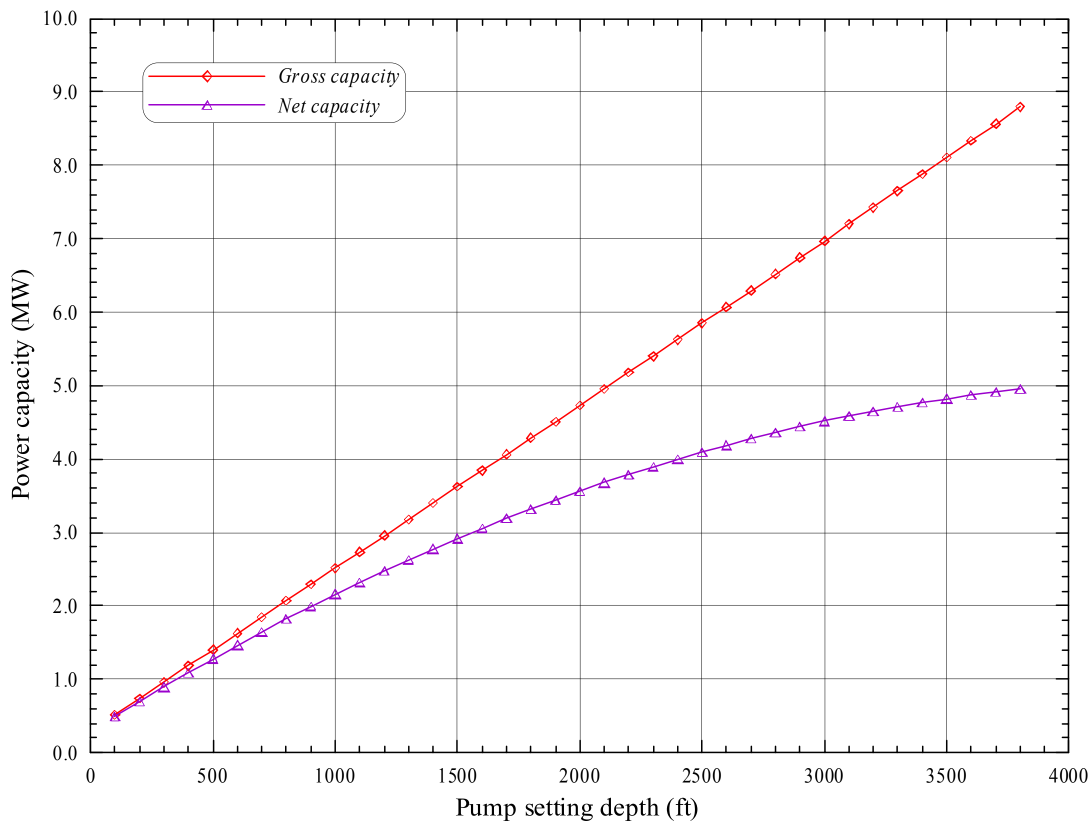


**Figure 4: Power capacity available from well RRGE-1 vs. pump setting depth for 5-well scenario**

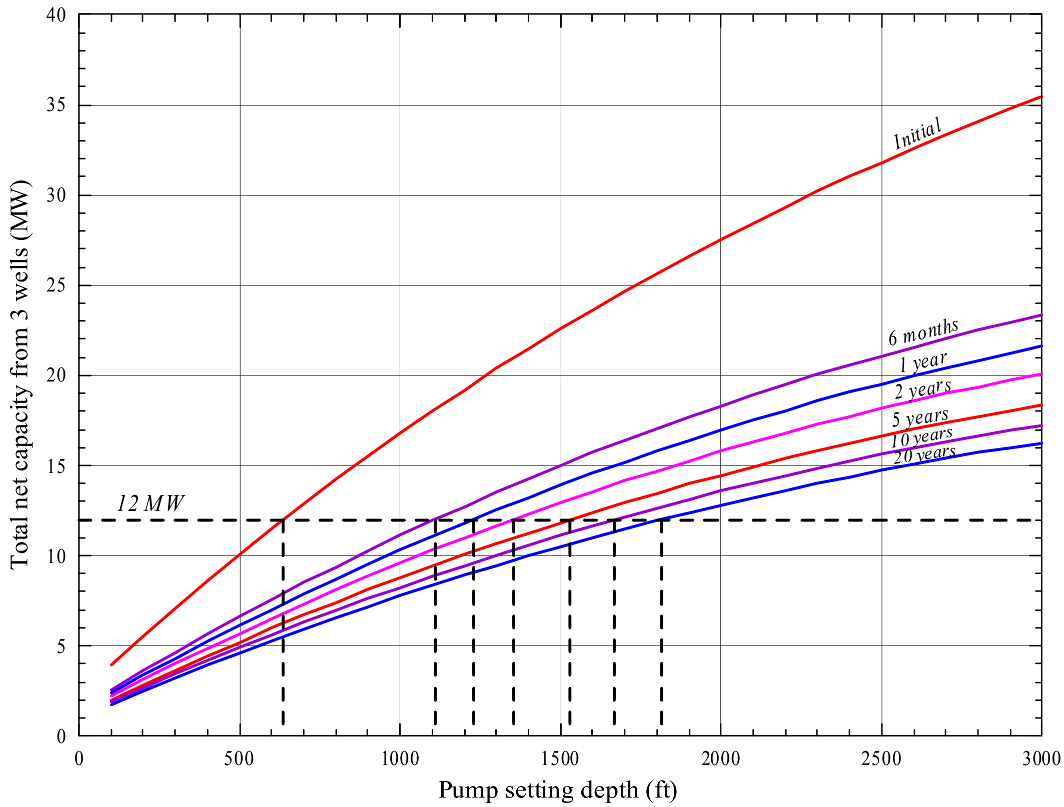


**Figure 5: Total net capacity available from 3 wells vs. pump setting depth**

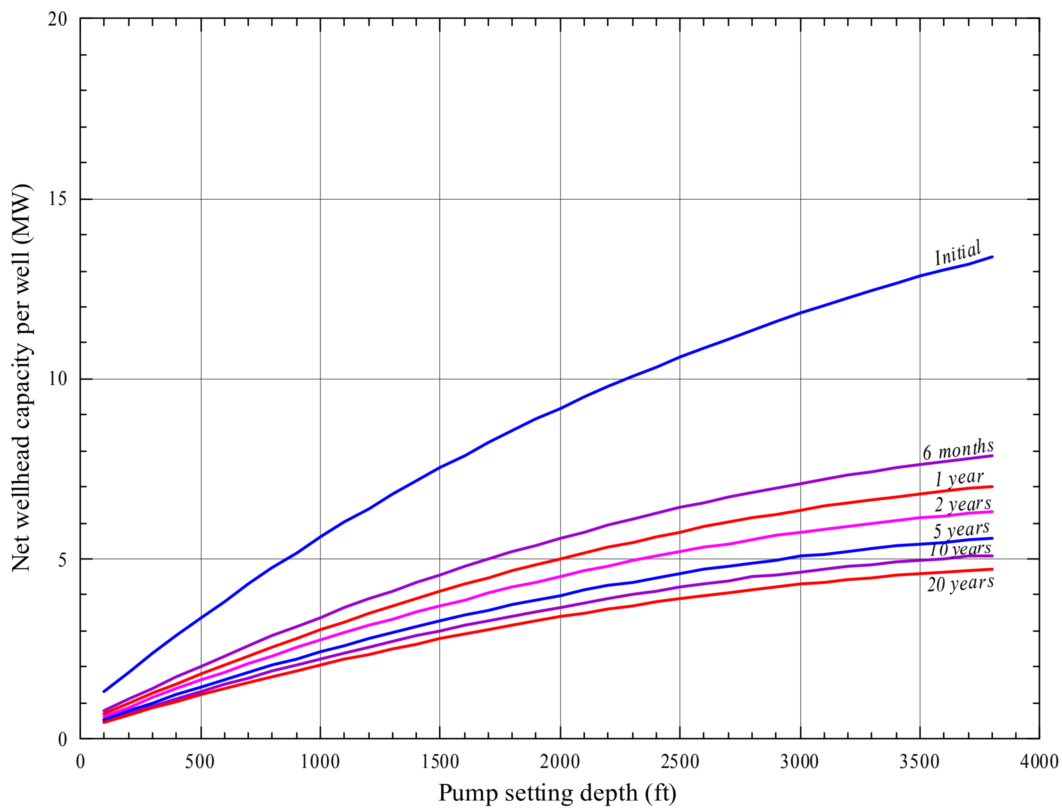


**Figure 6: Net wellhead capacity per well vs. pump setting depth for 5-well scenario**

We have considered a 17 MW (net) development scenario for the 5-well case with 3 options: (a) maintaining plant capacity with a fixed pump setting depth but drilling make-up wells as well productivity declines with time, (b) maintaining a plant capacity by increasing the pump setting depth as well productivity declines with time; and (c) maintaining plant capacity by a combination of increasing the pump setting depth and make-up well drilling. We have further assumed that in order to sustain uninterrupted generation, approximately 10% standby generation capacity will be maintained at all times; in other words, the actual plant capacity will be kept around 17 MW x 110% or 18.7 MW (net); such a stand-by capacity requirement is typical in the industry.

Figure 7 shows the decline in the 17 MW (net) plant capacity (assuming a 472m pump setting depth, which is the limit for a line-shaft pump) as a function of time and the number of wells (original 5 plus make-up wells drilled) needed to maintain plant capacity (at the level reached after 6 months). This figure shows that, if pumps are set at 472m, a 17 MW (net) plant can be supported by using the 5 existing wells plus 3 make-up wells drilled approximately 1 year, 5 years, and 10 years after plant start-up. The solid curve in Figure 7 shows the forecast of decline in plant capacity without the drilling of make-up wells and the dashed curve shows the plant capacity given the increases in the number of wells shown by the step-wise curve. It is seen that make-up well drilling can maintain the generation level between 18.2 to 20.1 MW (net) throughout the plant life.

Figure 8 shows, for a 17 MW (net) plant capacity, the forecast of increases needed in pump setting depth in the absence of make-up well drilling. The solid curve shows the decline in plant capacity without deepening of pump setting and the dashed line shows the 18.7 MW (net) capacity level that could be maintained by gradual deepening of the pump setting (shown by the step-wise curve).

Comparing Figures 7 and 8 it is clear that an optimum scenario for maintaining a 17 MW (net) plant capacity would be to deepen the pump setting for the first 10 years of project life, at which time the pump setting depth would still be a feasible 762m. If a make-up well is then drilled (at year 10) and the pump setting depth thereafter is kept at 762m, the project most likely will not need any more make-up wells over the remaining 10 years. As regards injection, it is very unlikely that the two existing injectors will have adequate injectivity to accept the fluid produced from 5 wells; therefore, one to three new injection wells will be required.

An eventual net plant capacity of 30 MW at Raft River is foreseen by the developer (U.S. Geothermal, Inc.). The reserves available within the leasehold will be adequate to support such a plant. It has been shown above that a 17 MW (net) plant can be supplied by 5 wells with either make-up wells drilled, or pump setting deepened or both, with time. Obviously, a 30 MW (net) plant would call for drilling some new wells in addition to working over or redrilling the existing ones. If the reservoir properties are uniform over the field and the new wells are spaced such that the average well spacing in the field remains the same as now, a 30 MW (net) plant will need, in proportion to a 17 MW (net) plant supplied by 5 production wells, 9 to 10 production wells, including any existing ones restored to production. As for injection, in comparison to other similar projects, perhaps 7 to 9 injection wells will be needed (to inject the production from 9 to 10 wells), including any existing ones restored to injection.

## 6. CONCLUSIONS

- Even with a conservative set of assumptions we conclude that it should be possible to supply a 10 MW (net) power plant at Raft River using binary-cycle power conversion and downhole submersible pumps if only 3 of the existing production wells can be restored to their full productivity by working them over. It is likely that no injection wells will need to be drilled as some of the existing injection and/or production wells can be worked over and used for this purpose.

- If all 5 wells can be made fully productive, it should be possible to supply a 17 MW (net) power plant by either deepening the pump setting with time, or drilling up to 3 make-up wells over a 20-year project life, or a combination of these options. In this case, one to three new injection wells will need to be drilled.

- A 30 MW (net) plant capacity is likely to be supportable by 9 to 10 production wells and 7 to 9 injection wells, including the existing wells refurbished for production or injection.

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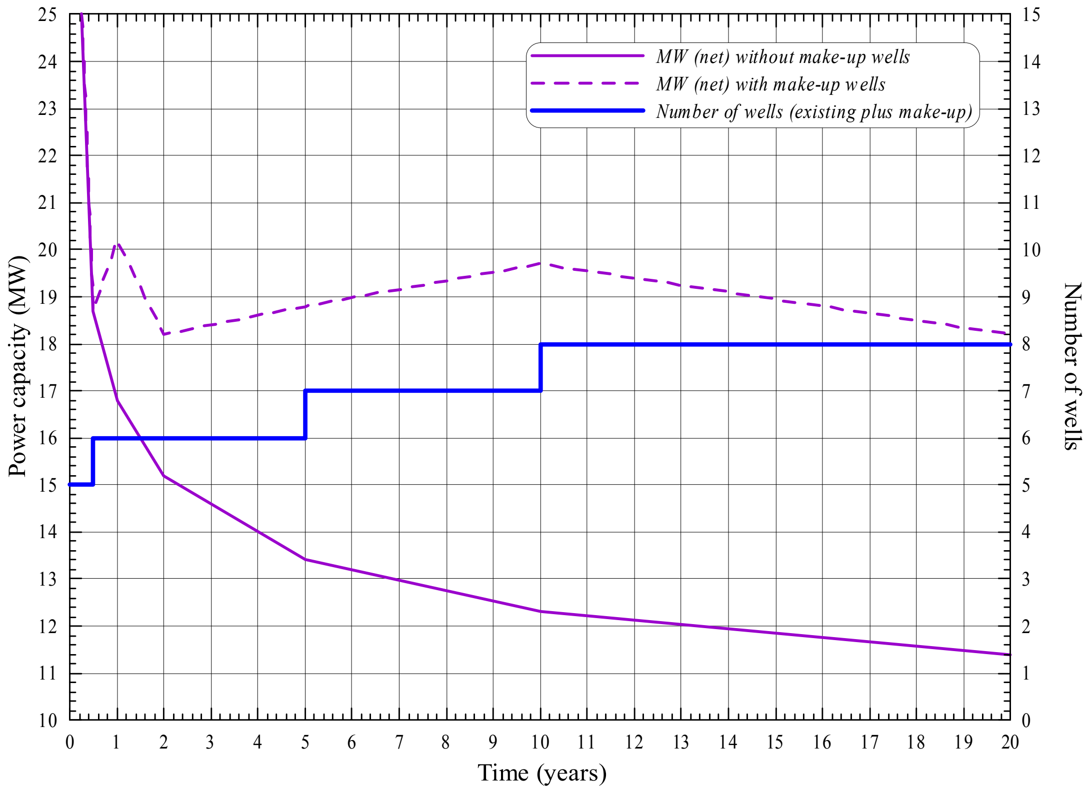


**Figure 7: Forecast for 17 MW (net) capacity (with a 1,550 ft. pump setting and make-up wells)**

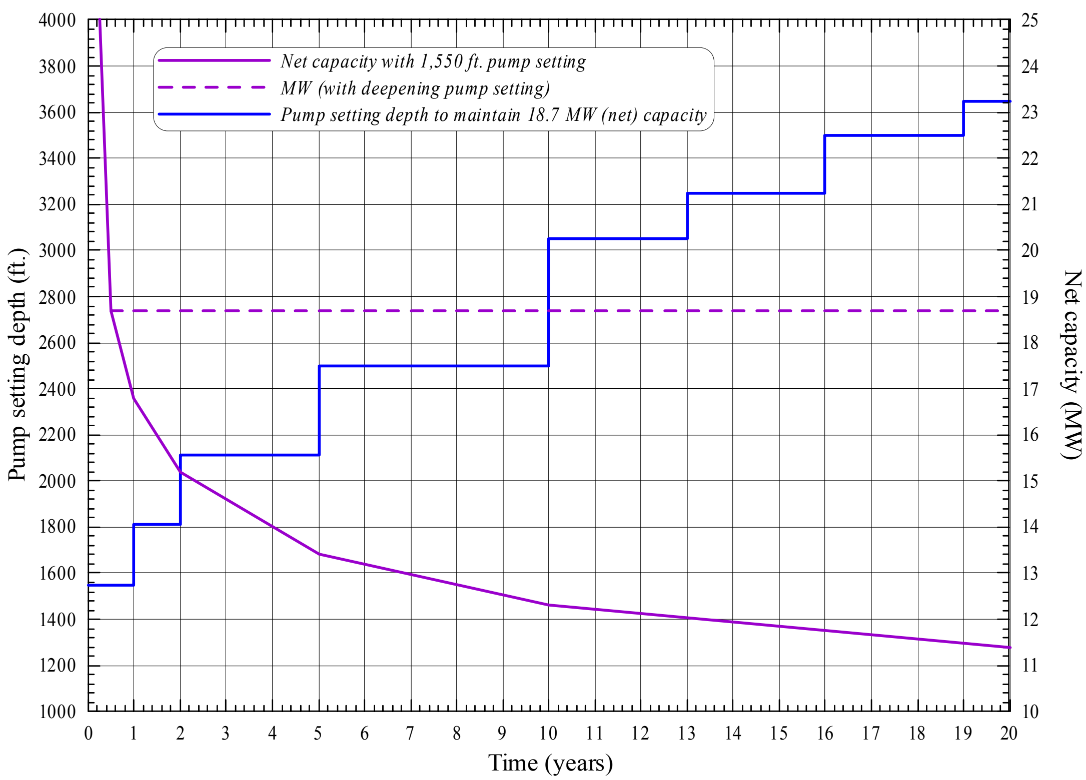


**Figure 8: Forecast for 17 MW (net) capacity (with deepening pump setting and no make-up wells)**