PROCEEDINGS, Thirty-Seventh Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, January 30 - February 1, 2012
SGP-TR-194

IMPROVED POWER PRODUCTION EFFICIENCY OF HYDROTHERMAL RESERVOIRS USING DOWNHOLE PUMPS

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ABSTRACT

This study investigates the potential of using electric submersible pumps (ESP) for power production in high temperature geothermal fields currently being produced using two phase flashing systems. The use of downhole pumps is predicted to have two benefits, the first being an increase in mass flow per well which could potentially reduce the number of wells and subsequently, drilling costs. The second benefit the pumps can provide is the prevention of exergy loss due to the flashing process, which occurs under conventional two phase wellbore flow. It is predicted that the power consumed by the pump can be recovered at the power plant resulting in higher energy output for each wellbore drilled. In addition to increased power production the study investigates the economic benefits of increasing the mass flow from each well to determine if pump maintenance costs and power consumption could be offset to yield higher returns for plant owners. A brief summary of potential social and environmental benefits for a closed loop approach is also discussed as the authors predict these may become of increasing importance in coming years.

INTRODUCTION

In recent years, much of the focus of geothermal research has been on enhanced geothermal systems (EGS); this is primarily due to the lack of naturally occurring hydrothermal systems available around the world. While many of these systems are artificially fractured hot dry rock, the same approach to production could be applied to high temperature hydrothermal systems to ensure that the most power is being extracted for each well drilled.

Methods utilizing pumps to produce geo-fluids as hot brines have allowed producers to extract more brine per well than would have been possible under natural flow. Unfortunately, current downhole pumps are limited to temperatures around 200°C and a setting depth of 457m (Sanyal, 2007). The development of electric submersible pumps (ESP) which could be utilized at higher temperatures and placed deeper than existing shaft driven pumps are predicted to yield an increase in net power per well.

A high temperature and pressure electric submersible pump could allow producers to use geothermal brines as single phase fluids. Using geothermal fluids as single phase liquids will result in higher brine temperatures if the steam phase is not created; and prevent the exergy from being lost during the creation of the secondary steam phase.

The first law of thermodynamics demands that the enthalpy for each kilogram of geothermal fluid remains constant as the fluid changes from a liquid to a two phase mixture. Figure 1 below shows the exergy destruction per kilogram of fluid, if the fluid was taken to the ambient dead state temperature and pressure. While the saturated brine has the same enthalpy as the two-phase fluid, it will have more available exergy than its two-phase counterparts, indicating that some exergy is lost to the phase change during production.

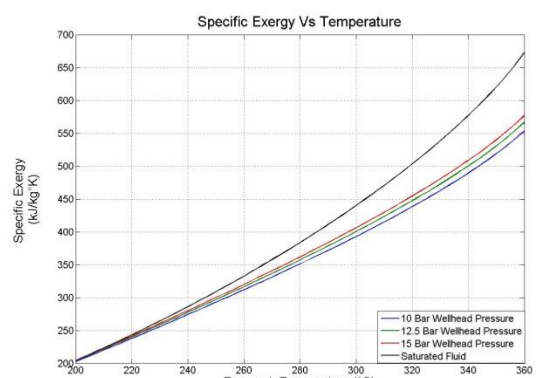

Figure 1: Calculated available specific exergy for a geothermal fluid at saturation pressure as well as 10, 12.5 and 15 bar wellhead pressure.

The curves in Figure 1 could also be plotted as functions of steam quality, as they are subject to a relevant flowing wellhead pressure. As the wellhead pressure approaches the fluid's saturation pressure the curves will come together. Unfortunately, this could mean no production for a conventional geothermal well. In addition to the gains in available exergy, single phase brines would be hotter than a two phase mixture of similar enthalpy; this could potentially run a power cycle more efficiently at the resulting higher temperatures.

METHODOLOGY

In order to study any potential gains in efficiency the reservoir/plant system was studied as a whole. Simple power plant models, reservoir models and economic models were used to evaluate and compare the proposed production methods.

Power Plant Models

The types of plants considered in the study were single-flash (Figure 2), double-flash (Figure 3) and an organic Rankine cycle or ORC Plant (Figure 4) with various hydrocarbon fluids. The analysis of the plants was done using a nodal technique where each component in the plant is assigned an upstream and downstream node; the systems' fluid properties such as temperature, pressure, enthalpy, entropy, quality were determined at each node.

Table 1: Cycle and Operational Parameters used in the study's Power Plants.

Parameters used in the Analysis	
Parameter	**Value**
Dead State Temperature	278.15°K
Dead State Pressure	100 KPa
Heat Exchanger Pinch	5°C
Water Turbine, η_T	70%
ORC Turbine, η_T	90%
Pump Efficiency, η_P	90%
Cooling Water Inlet Temperature	5°C
Cooling Water Discharge Temperature	40°C
Minimum Turbine Steam Quality	85%

Assumptions common to all of the plant models are negligible pressure and heat loss in all pipes and vessels. In addition to the pipes, the heat exchangers and condensers and turbines also had no external heat loss or gain. Table 1 shows a summary of some of the common cycle inputs and operational parameters. The environmental inputs used such as dead state temperature, were similar to those of the Krafla geothermal field in northern Iceland.

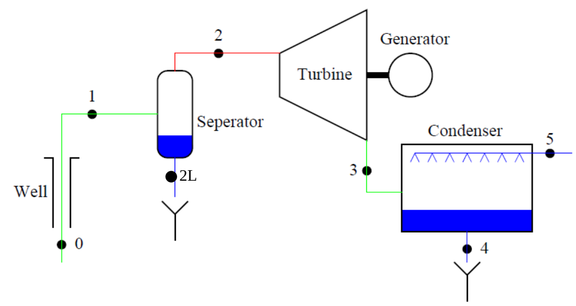

Figure 2: Process diagram for a single-flash power plant with condenser. (Pálsson, 2009)

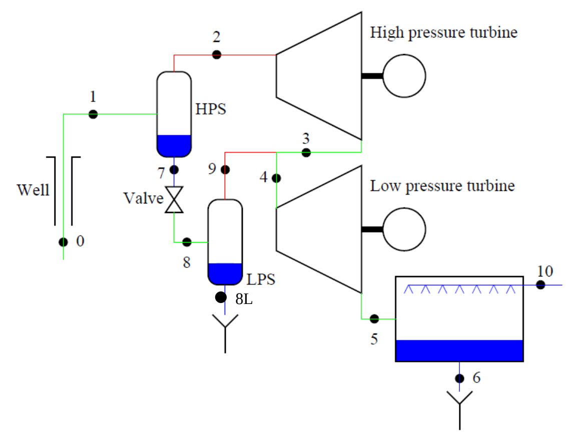

Figure 3: Process diagram for a double-flash power plant. (Pálsson, 2009)

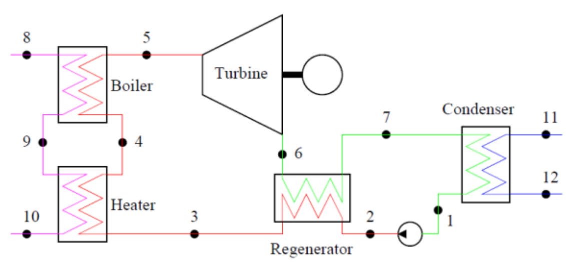

Figure 4: Process diagram for an ORC power plant with recuperator. (Pálsson, 2009)

The equations used to evaluate the flashing technologies are shown in Table 2, while the ORC plant was calculated using the equations in Table 3. All of the reference fluid properties used in the study came from a program called REFPROP (Lemmon, 2007).

Table 2: Energetic and exergetic relations used for flashing plant Analysis.

Component	Energy Relation	Exergy Relation
Flash Chamber(s)	$h_0 = h(x_1,P_1)$	$E_{FC} = T_0\, m_1\, (s_1\text{-}s_0)$
Turbine(s)	$W_T = m_2\, (h_2\text{-}h_3)$	$E_T = T_0\, m_2\, (s_3\text{-}s_2)$
Condenser	$Q_C = m_3\, (h_3\text{-}h_4) = m_5\, (h_4\text{-}h_5)$	$E_C = T_0\, (m_4 s_4 - m_3 s_3 - m_5 s_5)$
Reinjection	----	$E_R = m_{2L}[(h_{2L}\text{-}h_0) + T_0(s_{2L}\text{-}s_0)] + m_4[(h_4\text{-}h_0) + T_0(s_4\text{-}s_0)]$

Table 3: Energetic and exergetic relations used for ORC plant Analysis.

Component	Energy Relation	Exergy Relation
Boiler	$Q_B = m_3\, (h_5\text{-}h_3) = m_8\, (h_8\text{-}h_{10})$	$E_B = T_0[m_3(s_5\text{-}s_3) + m_8(s_8\text{-}s_{10})]$
Turbine	$W_T = m_5\, (h_5\text{-}h_6)$	$E_T = T_0\, m_5\, (s_6\text{-}s_5)$
Condenser	$Q_C = m_7\, (h_7\text{-}h_1) = m_{12}\, (h_{11}\text{-}h_{12})$	$E_C = T_0\, [m_7\, (s_7\text{-}s_1) + m_{12}\, (s_{11}\text{-}s_{12})]$
Recuperator	$Q_{RE} = m_2\, (h_3\text{-}h_2) = m_6\, (h_6\text{-}h_7)$	$E_{RE} = T_0[m_2(s_3\text{-}s_2) + m_6(s_6\text{-}s_7)]$
Reinjection	----	$E_R = m_{10}[(h_{10}\text{-}h_0) + T_0(s_{10}\text{-}s_0)]$

Wellbore Modeling

The wellbore modeling is also based on a nodal analysis technique, meaning the flow path from reservoir to power plant will be broken down into sections and evaluated individually. The first portion of this process will involve taking the geothermal fluids from some boundary point in the reservoir (node 1) to the bottom of the wellbore (node 2), as seen in Figure 5. The aim of the model is to estimate a steady state flowing bottom hole pressure at a specified mass flow rate.

Considering the wellhead as node three, the tubing and casing design can be optimized for either cost, work or a combination of both. The pipeline design from wellhead to plant separator or heat exchanger could be optimized as well in practice, but will be omitted for this project for both time constraints and relevance to the scope of the project.

Reservoir Model

The reservoir was not a main focus in the study; however, a simple model was needed to estimate of an appropriate pump setting depth. As a steady-state value was desired, no attention was given to the transient behavior. The simple model does not account for skin factor or turbulence in the formation; however, it provided a starting point for wellbore modeling purposes. The reservoir properties are from (Bodvarsson, 1989) with the remainder coming from Dr. Gudni Axelsson (Axelsson, 2009). A summary of the Krafla reservoir properties can be seen in Table 4.

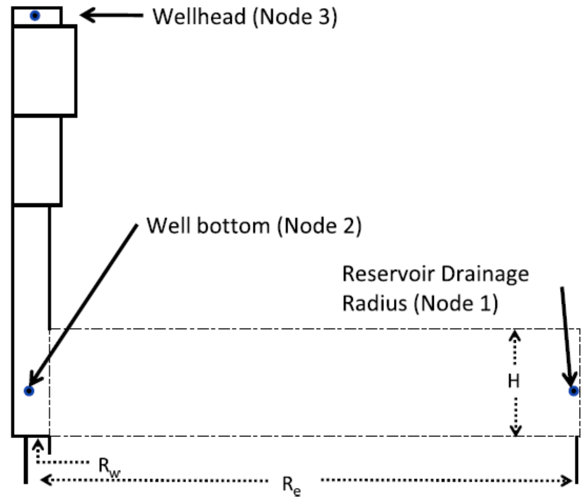

Figure 5: A visual representation of the 2-D reservoir model.

After the reservoir was characterized, the steady state flowing bottomhole pressure was estimated using the Van Everdingen and Hurst model (Towler, 2002). The model assumes an initial and constant boundary pressure of 200 bar, which is meant to simulate the effects of fluid reinjection. The model also needs a dimensionless radius; a value of 4000 was used in the study.

Table 4: Parameter's used in the reservoir model.

Parameters used in the Wellbore Solutions	
Parameter	**Value**
Formation Permeability (md)	5
Permeability Thickness (Dm)	2.55
Hydrothermal System Permeability (Dm)	100
Porosity (%)	4
Reservoir Temperature (°C)	300
Total Dissolved Solids (ppm)	0
Non Condensable Gases (% mass)	0
Formation Compressibility (Pa^{-1})	$3*10^{-11}$
Water Compressibility (Pa^{-1})	$4.4*10^{-11}$

The reservoir model yields a productivity index (PI) of approximately 11.7 (l/s/bar) at a depth of 2500m, and this value was used in subsequent pump setting depth calculations.

Single & Two-Phase Wellbore Models

The method described in the reservoir section provided an estimation of the flowing pressure at the bottom of the wellbore. The next step in the nodal analysis will involve moving the fluids from the bottom of the well to the wellhead at some constant mass flow rate. The flowing wellhead pressure is a function of mass flow, depth, pipe diameter and the properties of the fluid being transported.

The project assumes two identical base configure-ations with a pump added to the pumped wells. This assumption was made to simplify the economics portion of the study. A graphical representation of the wellbores is shown in Figure 6.

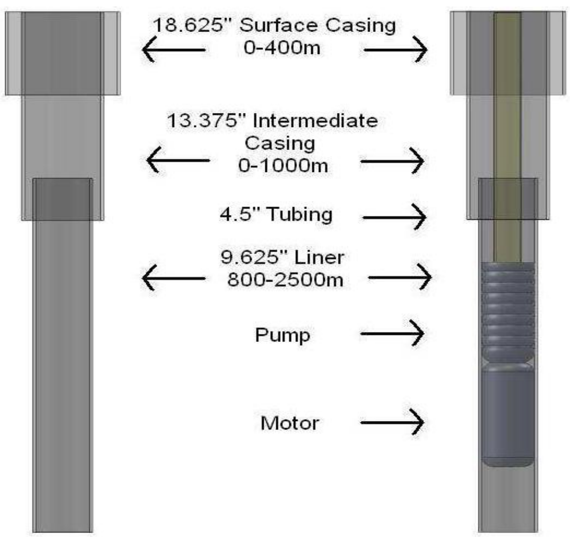

Figure 6: The two wellbore configurations used in the study.

While it is generally accepted that the single phase pressure loss equations for Newtonian fluids in pipes is relatively accurate, the two-phase measurements are far from perfect, with many commonly used correlations still having sizable margins of error. The two-phase model used in the project was the Friedel correction factor; it was selected for its relatively low amount of error compared to the other models. The model is based upon the single-phase fluid pressure drop would be for a given length of pipe, afterward, it's multiplied by a two phase scaling factor to estimate the two phase pressure drop for that given length of pipe.

The single-phase pressure drop was calculated using Equation 1, the acceleration term was dropped as it is normally a relatively small number.

$$\frac{dp}{dL} = g\rho cos\theta + \frac{f\rho v^2}{2D} + \frac{\rho v dv}{dL} \tag{1}$$

Where: v = fluid velocity,
g = gravitational constant,
ρ = fluid density,
D = casing/tubing ID
f = friction factor,

The two-phase is simply the single phase pressure drop multiplied by the Friedel correction factor (Friedel, 1979) represented by Φ^2.

$$\Delta P_f^{Two\ Phase} = \Phi^2 \Delta P_f^{Single\ Phase} \tag{2}$$

Where: $\Delta P_f^{Two\ Phase}$= Two-phase pressure drop,
$\Delta P_f^{Single\ Phase}$= Single-phase pressure drop,
Φ^2 = Friedel Correction Factor,

As the Friedel correction factor is quite computationally intensive, not all steps will be shown in this paper. And finally, the ESP's work was estimated using Equation 3.

$$W_{Pump} = \frac{(P_{Discharge} - P_{Suction}) * Q_{Brine}}{\eta_{Pump}} \tag{3}$$

Where: W_{Pump} = Pump Work,
$P_{Discharge}$ = Discharge Pressure,
$P_{Suction}$ = Suction Pressure,
Q_{Brine} = Flow Rate,
η_{Pump} = Pump Efficiency,

The pump was set 100 m below the estimated boiling depth assuming the well was being produced at a given flow rate. On the discharge side, a 2 bar safety factor was maintained over the boiling pressure for each reservoir temperature. The pump was assumed to be about 90% efficient, because it would have many stages run together.

Economic Model

Initially, the economics model for the project was going to include all costs ranging from transmission lines to operational costs. The grand scale comparison became difficult because of the massive variation in power development costs recorded and estimated from various authors over the years. In an effort to keep the comparison fairly transparent, the economic models were simplified to make the comparison as direct and relevant as possible. The simplifications were meant to highlight any advantages or disadvantages in power production seen in the plants and at the wellhead.

Intuitively, it's easy to imagine that the exploration, transmission, administration and costs based on the reservoir should be similar regardless of the technology used, so the comparison could just as well be made without these expenditures. The costs remaining to be compared are those of the wellbores and the power plants, which usually accounts for approximately three quarters of total development costs (Geothermal Energy Association, 2005). While it's generally accepted that binary plants are more expensive than flashing technology, a large area of overlap is seen in the cost figures between double-flash and binary development costs. In addition to the installation costs overlapping, the maintenance costs associated with single-phase fluids are reported lower than their multiphase counterparts in both the plants and wellbores. If those assumptions are accurate, it might be reasonable to assume that savings in initial installation costs would be lost to higher maintenance costs later. In any event, the total costs associated with the plants should be about fifty percent (Geothermal Energy Association, 2005).

As a result of the simplifications, we are left comparing wellbores with three different types of power cycles. And to compensate for the differences in wellbore costs, which are also highly variable, a 2500m wellbore base case comparison was chosen.

The tubing costs came from Iceland Drilling and Alberta Tubular. The missing tubing sizes, were provided by Alberta Tubular and common casing sizes where used to correlate what the tubing should cost in Iceland.

The cost estimate for the downhole pump was taken from the work done by the"Lemelson Report" (The Foundation for Geothermal Innovation, 2009). The report estimated the pump would cost roughly three quarters of one million U.S. dollars. In the study, the pump cost estimate was assumed to include cabling, installation and perhaps a variable frequency drive; although these costs could be in addition to the 750,000 USD. The pump and tubing were also assumed to be replaced every three years. No work-over rig costs for either model were assumed since the demands of the work-over can vary significantly depending on corrosion rates and scaling.

The final component of the model took the optimal mass flows for each production tubing size and temperature range and paired it to the optimal power output for each type of cycle at that temperature. The total costs of both wellbores were then compared to the power being produced or net power in the case of the pumped well. This allowed for some performance indicators to be calculated and provided a comparison based on both installation costs and a thirty year net present value. The specific values used in the economic models are summarized in Table 5.

Table 5: Parameter's used in the Economic model.

Parameters used in the Economic Model	
Parameter	**Value**
Pump Setting Depth (m)	Variable
Tubing Cost ($/m)	Size Dependent
Base Case Wellbore (millions, USD)	3.92
Pump Cost (USD)	750,000
Power Price (USD/kwh)	0.04
Plant Life (Yrs)	30
Interest Rate (%)	5
Maintenance Frequency (Yrs)	3
Maintenance Cost	Pump + Tubing
Additional Maintenance Costs	Not Considered

RESULTS

Power Plant Results

The results of the single and double-flash cycles are as shown in Figure 7. The thermal efficiencies and amount of work increase with reservoir temperature. The values calculated by the model match typical reported values for first law efficiency in the 5-15% range for the single-flash plant and 6-18% for the double-flash plant. The working fluids of binary closed-loop systems have an advantage over flashing technologies because of the ability to be used in supercritical conditions at substantially lower temperatures; the results indicated first law efficiencies ranging from 8-21%. Figure 7 shows the power retrievable per kilogram of geothermal fluid.

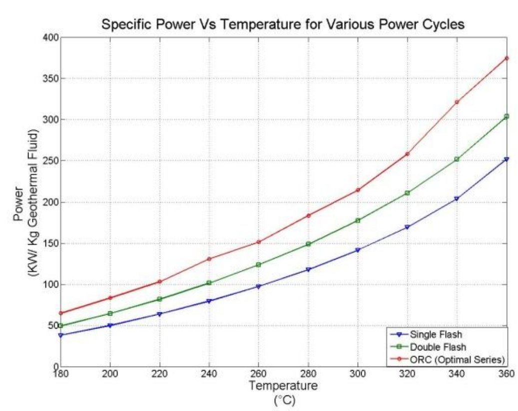

Figure 7: Specific power vs. temperature for the single-flash, double-flash and optimal organic Rankine series.

Wellbore Modeling Results

The results for the conventional wellbore modeling are shown in Figure 8. The pressure drop equations were applied to the same wellbore and reservoir at different mass flow rates to obtain the flowing wellhead pressures shown in the diagram. In the diagram, many of the fluid temperatures do not meet the vertical axis. This is because the wellhead pressure went into negative values at the higher mass flow rates. The flowing wellhead conditions also had to meet the criteria of being higher than the single or double-flash separator pressures. This constraint meant the wells could not flow at their absolute open flow potential.

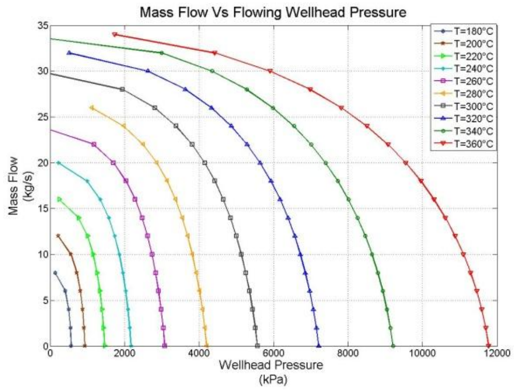

Figure 8: Mass flow vs. flowing wellhead pressure for various reservoir temperatures.

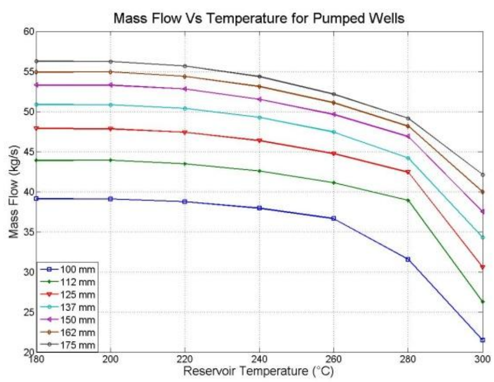

Figure 9: Mass flow vs. reservoir temperature for the pumped wells with various production tubing diameters.

The mass flow modeling for the pumped wells shown in Figure 9, was more involved since there were more variables and constraints in the system. In addition to the pressure gradient, a pump setting depth had to be determined and a second gradient applied to account for the smaller production tubing. Unfortunately, the pumps also had an inherent constraint on the setting depth. This was encountered at temperatures over 300°C. It was found that in order to satisfy the studies'100m of hydraulic head on the pump suction constraint, the pump would have to be set deeper than the well. The boiling point of water at temperatures over 300°C would need wells deeper to utilize downhole pumps. A similar occurrence was also noted when excessive drawdown in the higher temperature reservoirs lead to the formation of steam, these conditions would make pump use impractical or impossible.

Figure 9 represents the optimal balance of pressure and flow rate for the well and plant system. In the plant and wellbore system, the amount of useful work per kilogram of geo-fluid was balanced with the work provided to the pump until the best solution was found.

The final result of combining the wellbore modeling with the power plant studies is shown in Figure 10. After obtaining values for mass flow from the two styles of wellbores, we are able to estimate the amount of power that can be produced from each wellbore. The graph is based on the specific power of each type of power cycle at a given temperature and was multiplied with the wellbores' mass flow at that given temperature. As mentioned previously, the pumps would not work at temperatures over 300°C, so no data is presented for temperatures over 300°C.

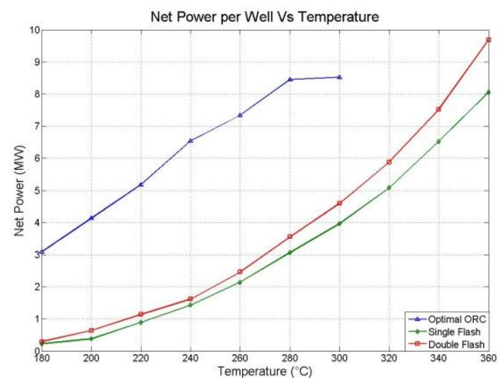

Figure 10: Net power per wellbore vs. reservoir temperature for various power generation techniques.

Economic Modeling Results

The installation costs for the binary wells all trended down with increased production tubing diameter, with the most dramatic differences being observed in the lower temperature reservoirs. The production tubing hit a diameter constraint in the wells' slotted liner; $7^{5/8}$ inch would be the largest diameter of standard casing that could be run with couplings.
The lighter $7^{5/8}$ inch pipes have an inside diameter of 175mm which became the upper limit for the study. The trends did level out around this point in many of the higher temperatures indicating that an optimum diameter may be near this location.

It is evident when looking at Figure 11 that installing flash technologies at low temperatures could be quite an expensive endeavor and likely will not be cost effective any time soon. The flashing costs do drop quickly, however, and the technologies could be considered comparable by around the 300°C region, especially when you consider the challenges associated with new technology and the extra maintenance required for the downhole pumps.

Figure 11: Installation cost vs. reservoir temperature for various power generation techniques.

While much focus in development is focused on installation costs, it can be beneficial to look at long term economic viability. The economic model assumed the pump and production tubing would be replaced every three years. Material prices and power price were also assumed to remain constant over the thirty year period as the year to year interest rate would keep at a constant five percent.

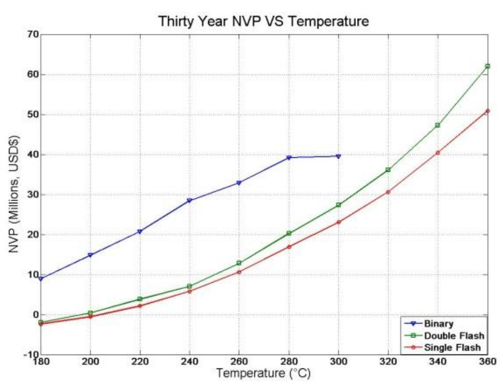

Figure 12: Net present value vs. reservoir temperature for various power generation techniques.

The results of the economic model are shown in Figure 12, and depict the conditions where this technology is most advantageous over the flashing wells. While the Figure 12 has a similar profile to Figure 10, the cost of replacing the pump and tubing had a negative impact on the pumped binary advantage previously seen in Figure 10. The highest gains in returns are now seen in the 240°C to 280°C range. Once again, no data is available for temperatures over 300°C. The graph also shows a negative value for the low temperature flashing technologies, which may be why there are not many low temperature flashing plants operating around the world. While the flashing technologies could work at 180°C they would be unprofitable at the power prices used in the study. The negative value seen in Figure 12 represents a net loss after 30 years of operation.

DISCUSSION

A primary focus of the study was to investigate any advantages or efficiency gains when using saturated brine, as opposed to a two-phase mixture, for power generation. During the trials the optimization software was allowed to maintain the brine as a saturated liquid or a two phase mixture. In all but one trial, the solver found a saturated liquid to be optimal.

Similar to the brine, the optimization software allowed the ORC working fluids' were to run as saturated steam, superheated vapor and in the supercritical state. All except one of optimal solutions had working fluids in the supercritical region. One of the cyclohexane trials found a saturated vapor solution which produced more power than a supercritical hexane cycle at the same temperature. The saturated vapor solutions were seen in fluids at temperatures below the critical temperatures; however, these solutions typically did not outperform the lighter molecular weight fluids running in supercritical conditions. The saturated vapor cyclohexane solution could be attributed to a missing working fluid which would fit between hexane and cyclohexane for molecular weight and boiling point. Another possibility could be that the temperature profiles of the brine and cyclohexane sides of the heat exchanger fit together to maintain the pinch tolerance, but destroyed minimal exergy in the heat transfer process.

An unforeseen problem encountered in the study was the pump cavitation. While it was easier to set the drilling costs equal for a 2500m well, it did introduce the pump setting depth problem. It would have been relatively easy to use a 3000m or deeper well to ensure that the pump could be set deep enough to prevent suction cavitation; but it would be impractical for the lower temperature reservoirs and would have not changed the two-phase well case. Ultra deep wells may not be needed in hydrothermal fields, as they are in conventional EGS fields, as naturally occurring fractures can be used to conduct fluids from deeper in the earth to the pumps.

Another trend seen in Figure 9 involves the lines getting closer together as the tubing diameter increases, indicating diminishing returns as the tubing gets larger. The closing of the lines suggests the bottle neck might be in the reservoir or pump. In the 300°C result shown in Figure 9 the rate was restricted in the smaller diameter pipes in order to meet the pressure constraints, and limited because of boiling in the reservoir in the larger diameter pipes. This meant more power could be extracted from the 280°C reservoir than the 300°C reservoir, until the larger tubing diameters were used.

The closed loop systems have additional environmental benefits not investigated in the study, which could include:

• A reduction of gaseous emissions to the atmosphere
• Reduction in waste water handling (as most of it would be re-injected)
• Reduction in solid waste to the lands surface
• Potentially minimize the impact of scaling by keeping minerals in solution
• Brines may also be treated at surface with additives
• Reduce the cost of the gathering system due to smaller pipes
• A minimal impact on scenic areas with buried pipelines

CONCLUSIONS

Results of the study suggest that the use of downhole pumps in high temperature hydrothermal systems could lead to significant gains in power production. Although the ESP intended to be used is not currently available, it could potentially reduce the number of wells required to develop or sustain an existing geothermal field, thus reducing development costs.

The advantages of pumping disappear as the critical temperature of water is approached, due to an increase in well productivity and improved performance from the flashing cycles. Additional benefits of the downhole pumps could be a reduction of the social and environmental impacts of geothermal development in sensitive areas by leaving a smaller surface footprint than flashing technologies.

The challenges encountered in the study would suggest that well depths for these pumped hydrothermal wells will have to be governed by temperature and suction pressure rather than fracture locations and productivity index alone. While pump cavitation may seem like a trivial challenge to overcome, poor well planning or hotter-than-anticipated reservoir fluids could add additional workover and drilling costs if not addressed properly.

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