# COMMON CHARACTERISTICS OF PUMPED WELLS IN GEOTHERMAL POWER PROJECTS

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## ABSTRACT

Pumped wells in geothermal power projects share common characteristics, including the requirement for sufficient dynamic water level in the well above the pump to preclude gas breakout on the suction side of the pump. This dynamic water level is a function of resource temperature, static water level, flowrate, and well productivity, the interrelationship for which is explored in this paper.

A broad overview of existing pumped-well geothermal power projects is presented, including the range of fluid utilization (flowrate divided by power output). Discussions are presented on pump hydraulics and the influence of resource temperature and static water level on allowable drawdown and the corresponding minimum well productivity indices for a given power output.

The overarching purpose of this paper is to present together in one place the key elements of geothermal pumped wells that will aid the reader in understanding fundamental characteristics of pumped wells in existing power projects as well as potential expansions or greenfield sites.

## 1. INTRODUCTION

Pumped wells occupy a growing niche within the overall geothermal power industry. These wells use downhole pumps to produce the wells versus self-flow for other geothermal projects. The purpose of the pump is to achieve a commercial flowrate and boost the pressure to maintain the fluid in single phase to surface.

The suitability of a resource for pumped wells is a function of the resource temperature and productivity, as well as the static water level in the well. The combination of these factors must satisfy the requirement of maintaining sufficient dynamic water level above the pump to preclude gas breakout on the suction side of the pump.

This paper provides an overview of existing pumped-well projects, with discussions on well hydraulics, static water level, well productivity and permeability, and fluid utilization.

### 1.1 Terminology and units

A key metric for pumped wells is the ratio of flowrate to power output, which is referred to as *fluid utilization* in this paper, after common usage in the industry and in the literature. Units for fluid utilization used in this paper are gallons per minute per megawatt-electric (GPM/MWe). However, the concept of fluid utilization can take other forms, and has also been referred to as brine effectiveness and stated as watt-hours per pound of fluid (Hanson et al., 2014).

Another key metric for pumped wells is the productivity index (PI), usually expressed as volumetric flowrate per unit pressure drawdown such as GPM/psi, or liters per second per bar (l/s-bar). Productivity can also be expressed as mass flowrate per unit pressure drawdown (related to volumetric PI by fluid density). This paper generally uses GPM/psi unless otherwise noted.

Pumped wells have a gross and net power output; the difference between which is the power that the pump consumes (sometimes called the pump parasitic load). Net electricity sales also has to account for power consumed within the plant, although this paper is not concerned with plant parasitic load. Common terminology for well power output is in MWe, and for purposes of this paper the term MWe will mean gross power output from the well.

## 2. OVERVIEW OF EXISTING PROJECTS

Pumped-well geothermal power projects are primarily concentrated in the Western U.S., but expansion of these type of projects has occurred in recent years to include Europe and Turkey. Pumped wells for power generation typcially produce from resource temperatures between 100-190°C, which is sometimes referred to as “moderate enthalpy” resource (in the range of 400-800 kJ/kg fluid enthalpy). Fluid utilization varies widely from 250 GPM/MWe for the higher temperature resources to over 1,000 GPM/MWe at the lower temperature end. Individual pumped wells typically produce in the range of 1,500-2,500 GPM.

The following is a survey of pumped-well geothermal power projects by geographical region. Though not comprehensive, this overview provides the context for the following discussions on pump hydraulics and common characteristics of pumped wells.

### 2.1 Nevada

Nevada has the largest concentration of geothermal pumped-well power projects in the world, with roughly 620 MWe (gross) of installed capacity spread over some 14 fields. The author estimates approximately 3.5 million MWh (gross) were generated from pumped-well projects in Nevada in 2018 (generation data culled from the Nevada Division of Minerals website: minerals.nv.gov).

Nevada also contains the largest pumped-well project in the world (McGuiness Hills). As of 2016, McGuiness Hills was producing roughly 30,000 GPM of fluid to generate 117 MWe (Lovekin et al., 2016), which translates to an average fluid utilization of 256 GPM/MWe. Another power plant was added to McGuiness Hills at the end of 2018 to bring the total project above 170 MWe nameplate capacity.

Other major pumped-well projects in Nevada include Steamboat, Don Campbell, and Patua. Fluid utilization varies widely, from fields with relatively high resource temperatures in the range of 170-180°C such as McGuiness Hills and Tuscarora (Chaboro et al., 2015) with a fluid utilization of 240-260 GPM/MWe, to the lower temperature fields such Wabuska, Empire and Stillwater. Data from Hanson et al. (2014) indicate that Wabuska has the lowest resource temperature (104°C) and the highest fluid utilization (≈1,100 GPM/MWe). Those authors also show the effect of declining resource temperatures (mostly due to reinjection) on fluid utilization and capacity factor.

### 2.2 California

After Nevada, California has the second largest output for pumped-well geothermal projects with roughly 250 MWe of installed capacity. The author estimates approximately 1.2 million MWh (gross) were generated from pumped-well projects in California in 2018 (generation data culled from the California Energy Commission website: energy.ca.gov).

At one time the Ormesa-East Mesa complex with six power plants and 110 MWe of installed capacity was the largest pumped-well geothermal project in the world. In recent years this field has declined due to cooling in the reservoir as a result of both reinjection and incursion of cooler water from surrounding aquifers.

The other major pumped-well projects in California are Heber and Mammoth. Heber has both a flash plant facility (Heber Geothermal Company, commenced in 1985) and a pumped-well project (SIGC, commenced in 1993), which are now interconnected. The original SIGC design criteria contemplated a total flowrate of approximately 14,000 GPM generating some 44 MWe (gross), which translates to an average fluid utilization of 320 GPM/MWe. Subsequent updates on the project (e.g. Sones and Krieger, 2000) indicated that the project performed essentially as originally designed.

### 2.3 Utah

Cove Fort has been reported as a pumped-well geothermal project with nameplate capacity of 25 MWe and resource temperature between 170-180°C. The project has been operating since 2013 but there is little recent operating data available in the public domain to estimate capacity fluid utilization.

### 2.4 Europe

Most current pumped-well geothermal power projects in Europe are concentrated in the province of Bavaria, Germany. This area has been developed for both power and direct heat geothermal projects, with individual power projects being relatively small. Data published by Agemar (2014) indicates four power projects in the Molasse basin south of Munich between 3 to 5 MWe installed capacity, although recent news articles suggest that at least two more power projects of this approximate size have become operational in the same area since 2014 (e.g. ThinkGeoEnergy, 5 October 2018).

The author's information indicates that these power projects typically have pumped wells completed between 3,500-4,200 meters (m) of depth, with pumps set at 700 m (or deeper). Resource temperatures for these operating power projects range between 120°C to 140°C, with production rates typcially 110-135 l/s (1,740-2,140 GPM) and productivity indices of 8-20 l/s-bar (7-18 GPM/psi). Estimated fluid utilization for these wells based on reported output and flowrate is in the range of 400-450 GPM/MWe.

Although there is significant geothermal district heating activity in Europe, there are a limited number of geothermal power projects outside Bavaria. Exceptions are Velika Ciglena in Croatia (reported as 17 MWe) and Tura in Hungary (reported as 3 MWe).

### 2.5 Turkey

Turkey has approximately 300 MWe installed capacity for moderate enthalpy fields that utilize binary plants (Layman, 2017), but apparently only one operating project that uses pumped wells (the 15 MWe Buharkent project). The effect of high CO2 content on the gas breakout pressure for most of the geothermal fields in Turkey has precluded the use of downhole pumps (Haizlip et al., 2016). The Buharkent field is an exception, with a reported CO2 content of 0.2% by weight and resource temperature of 146°C, this resource is suitable for pumped wells.

## 3. PUMP HYDRAULICS

The characteristics of pumped wells are inseparably linked to the pump hydraulics. There are several types of pumps available, including line shaft pumps (LSPs) and electric submersible pumps (ESPs). The LSP type is by far the most commonly used. There is a healthy debate in the industry regarding pump technology, and useful references on this debate include Schroder and Schneider (2014), as well as a recent description of the state of ESP capability (Curkan et al., 2018). As LSPs are the most commonly used pump, this paper will primarily focus on their use in pumped wells, although the hydraulic fundamentals are the same for both LSP and ESP types.

The essential purpose of the pump is to boost the pressure at the pump intake sufficiently to maintain the fluid in single phase and provide the pressure and flowrate required at the plant inlet. There are many good descriptions for the mechanical design of LSPs and ESPs, including Culver (1998).

Pumps must be set deep enough such that the water level is maintained above the pump while pumping, defined here as the *dynamic head* (sometimes referred to as submergence head), provides the required *net positive suction head (NPSHR)* to prevent cavitation in the pump. The pump set depth refers to the depth of the first stage impellor. Usually a bubble tube is installed at this depth to monitor the downhole pressure, and the pumped flowrate is adjusted to ensure that the difference between static and dynamic water levels, defined here as *allowable drawdown*, is not exceeded.

The NPSHR is pump specific but is primarily dependent on the vapor pressure of the fluid and the amount of non-condensable gas (NCG) in the fluid. The pressure at which gas or air bubbles form in the fluid, which would cause cavitation in the pump, is defined as the *gas breakout pressure*. In practice, pumped-well applications are confined to resources with nil or very low NCG content in the fluid (see Appendix A.1).

The power that the pump motor must provide is largely determined by the pumped flowrate and *lift head*, defined here as the vertical distance from the dynamic water level to surface plus the required wellhead pressure and friction losses (sometimes referred to as total bowl head). Pump power required for commercial wells in geothermal power projects typically ranges between 500-1000 kW (see Appendix A.2).

### 3.1 Static water level

The static water level in a well is governed by the piezometric surface associated with the reservoir that the well is completed in. This piezometric surface is expressed in head (e.g. meters) of groundwater column above a certain datum (usually sea level) when the well is not producing. For brownfields already in production the overall field drawdown is superimposed on both static and pumping water levels.

In practical terms, the static water level is the height that the water will rise in the wellbore under well static conditions. For example, the regional hydrogeology may result in a piezometric surface at 1,000 meters above sea level (mASL) in the vicinity of a well with a ground surface elevation of 1,200 mASL. Provided the pressure at the surface of the water column is essentially zero (gage), the static water level in the wellbore in this case would be 200 m in depth. In some cases artesian reservoirs can result in a piezometric surface above ground surface, or the static water level can be depressed by gas pressure in the wellbore. Of primary concern in a pumped well is the static water level above the pump set depth, which we will define here as the *static head*.

## 4. CHARACTERISTICS OF PUMPED WELLS

Pumped wells in geothermal power projects share common characteristics, including the requirement for sufficient dynamic head to preclude gas breakout on the suction side of the pump. For a given temperature, the static head and productivity of the well determine the allowable drawdown and thus the dynamic head. The iterative relationship between these factors is represented in Figure 1, which shows the drivers (red arrows) and the feedback loops (black arrows) that ultimately determine the maximum pump rate.

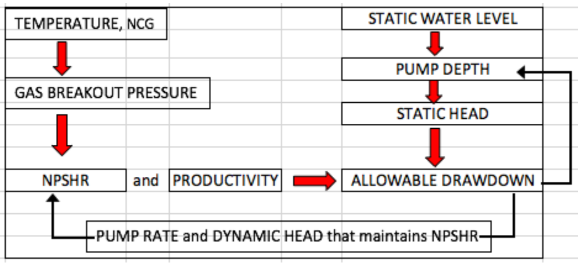


**Figure 1: Drivers controlling the pumped flowrate**

The well construction for pumped wells is similar to other geothermal wells except that line shaft pumps must be set in the straight portion of the well (the line shaft from the surface motor that drives the downhole impeller must be kept straight). Line shaft pumps are usually set inside 13 3/8” casing to accommodate the standard 11 ¾” pump size. Consequently, the predicted allowable drawdown is a factor in determining the depth at which the 13 3/8” is set, as this casing string must be set deep enough take into account pressure depletion over time (and corresponding decreasing water levels). Common pump set depths are 400-500 m, but can be adjusted to the static water level. If required to accommodate deeper static water levels, LSPs can be set as deep as 734 m (Paredes, 2018).

One way to look at the relationship in Figure 1 is to plot the allowable drawdown versus temperature and static head, as shown in Figure 2.

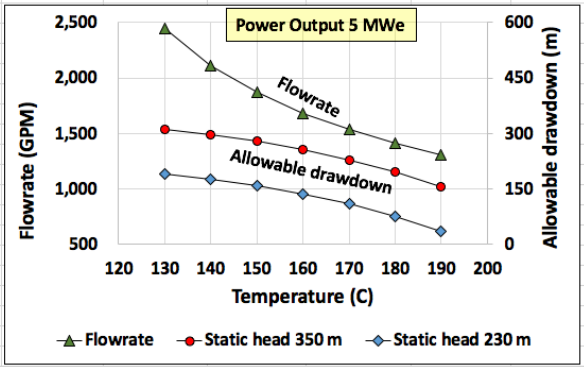


**Figure 2: Allowable drawdown as a function of temperature and static head**

Figure 2 illustrates that that for given power output (in this case 5 MWe), allowable drawdown (plotted on the right axis in meters) is directly proportional to the static head, and decreases with a slight downward concavity with increasing temperatures due to increasing fluid vapor pressure with temperature (the vapor pressure vs. temperature trend is not linear and exhibits an increasing slope with temperature). This example assumes nil to very low NCG content.

The required volumetric flowrate to produce 5 MWe shown in Figure 2 decreases with increasing temperature due to the increasing enthalpy of the fluid, but has a slight upwards concavity due to the effect of decreasing density with temperature (resulting in higher volumetric rates for given mass rates).

In practice most individual pumped wells operate in a narrow range of 2 to 7 MWe, limited on the high end by the effect of resource temperature on fluid vapor pressure and on the low end by commercial considerations, although it is technically feasible to operate outside this range.

### 4.1 Productivity and Permeability

The productivity of a pumped well is most often expressed as a volumetric index, usually in GPM/psi or l/s-bar. By application of the diffusivity flow equation, the productivity index (PI) can be related to the permeability-thickness (kh) of the formation that the pumped well is completed in. A simplified but useful conversion of PI to kh can be derived (see Appendix A.3) and written as Equation 1:

$$kh\ (d-m) = 12 * PI(GPM/psi) * \mu$$

Where $\mu$ is the fluid viscosity in centipoise (cp). For example, for a PI of 10 GPM/psi and a viscosity of 0.17 cp (for 160°C fluid), the estimated kh is about 20 darcy-meters (d-m). Volumetric PI values for pumped wells are typically in the range of 5-25 GPM/psi, although the PI can be much higher if the well is completed in a conductive fault or fracture zone (as in the case of McGuiness Hills) or highly permeable sandstone (as in the case of Ormesa).

Productivity and permeability are intrinsic properties of the reservoir that the well is completed in, and the range of minimum PIs for a given individual well power output can be understood in terms of temperature and static head as shown in Figure 3.

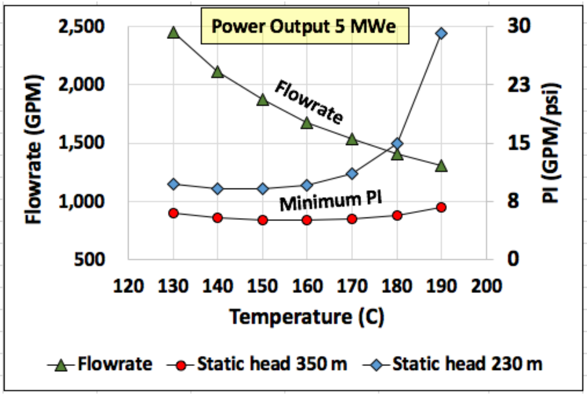


**Figure 3: Minimum productivity index as a function of temperature and static head**

Figure 3 illustrates that the minimum PI remains fairly constant with temperature for static head of 350 m, but increases rapidly with temperatures above 160°C for lower static head (shown is 230 m). This is a function of increasing vapor pressure of water with temperature which places a practical limit on resource temperatures for pumped-well applications of about 190°C. This interesting phenomena shows why "hotter is not always better" as aptly described by Sanyal et al. (2007), who also provide useful discussions on allowable drawdown and other pumped-well parameters.

### 4.2 Fluid Utilization

In addition to being dependent on temperature, the flowrates required for a given output as shown in Figures 2 and 3 are also a function of fluid utilization. Fluid utilization is the flowrate divided by the power output and is influenced by resource temperature and plant factors such as exit temperature of the resource fluid from the heat exchangers in binary power plants and plant thermal efficiency. For the binary power plant technology used in most pumped-well applications, the plant thermal efficiency can be related to resource temperature as shown in Table 1.

| Plant name (Location) | Inlet Temp. (C) | Plant Eff. (%) |
|---|---|---|
| Amedee (Ca.) | 103 | 5.8 |
| Wabuska (Nv.) | 105 | 8 |
| Brady (Nv.) | 109 | 7 |
| Husavik (Iceland) | 122 | 10.6 |
| Otake (Japan) | 130 | 12.9 |
| Nigorikawa (Japan) | 140 | 9.8 |
| Steamboat 2 & 3 (Nv.) | 152 | 8.2 |
| Ormesa II (Ca.) | 157 | 13.5 |
| Heber (SIGC) | 165 | 13.2 |
| Miravalles Unit 5 (Costa Rica) | 166 | 13.8 |

**Table 1: Thermal efficiencies for binary power plants** (reproduced from Table 7.2 of *The Future of Geothermal Energy*, MIT , 2006)

The best fit for the data in Table 1 is given in the 2006 MIT report as Equation 2:

Thermal Efficiency (%) = 0.0935 * T (°C) + 2.3266

The fluid exit temperature varies with plant design and ambient temperature (lower condenser pressures and greater plant efficiencies are associated with lower ambient air temperatures). In the illustrative case in Figures 2 and 3, the fluid exit temperature was modeled after the SIGC project in Heber, California, which had an initial design fluid exit temperature of 67°C. SIGC is a water-cooled binary project whereas most binary units are air cooled. Air-cooled units are more affected by ambient air temperatures, and colder climates, such as in Nevada or Bavaria, generally have lower fluid exit temperatures. Estimates of fluid utilization and the main factors which influence fluid utilization for selected fields are given in Table 2.

| Field | Resource temp. (C) | Est. fluid exit temp. (C)[1] | Est. thermal efficiency[2] | Est. Fluid utilization (GPM/MWe) |
|---|---|---|---|---|
| SIGC (Heber) | 165 | 67 | 13.2% | 320 |
| McGuiness Hills (Nevada) | 170 | 50 | 13.5% | 256 |
| Tuscorora (Nevada) | 172 | 50 | 13.7% | 248 |
| Kirchstockach (Germany) | 137 | 45 | 10.5% | 417 |
| Wabuska (Nevada) | 104 | 60 | 8.0% | 1105 |

**Table 2: Examples of fluid utilization for selected fields**

Notes for Table 2:
1 Estimated annually averaged fluid exit temperatures.
2 Estimated thermal efficiency based on the relationship given in Equation 2.
3 Sources of information: SIGC: author; McGuinness Hills: Lovekin et al. (2016); Tuscarora: Chabora et al. (2015); Kirchstockach: author; Wabuska: Hanson et al. (2014).

## 5. CONCLUSIONS

This paper provides an overview of existing pumped-well geothermal power projects and discussions on pump hydraulics and intrinsic characteristics of pumped wells. The key parameters controlling pump hydraulics are static and dynamic head and allowable drawdown.

The iterative relationship between pump hydraulics and the intrinsic properties of the well determine the pump rate and ultimately its suitability as a pumped well for power generation. This paper explores the drivers and feedback loops for this iterative relationship, and provides illustrative examples showing allowable drawdown and minimum productivity indices as a function of resource temperature and static head.

A simplified relationship for the conversion of productivity index to permeability-thickness is provided. The effect of non-condensable gas on the gas breakout pressure and a simplified method for estimating pump power are included in the Appendices.

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## APPENDICES

### A.1 The effect of non-condensable gas on gas break out pressure

The gas breakout pressure is additive of the vapor pressure of pure water plus the partial pressure of the gas which is dissolved in the water. Most non-condensable gas (NCG) in geothermal fluids is CO2. The relationship for estimating the partial pressure of CO2 is given in a number of references including Hosgor et al. (2015). Using the relationship provided by those authors, the gas breakout pressure for a CO2 content of 0.5% by weight in 170°C fluid increases to about 290 psia compared to 115 psia for the vapor pressure of pure water at that temperature. In other words the partial pressure of the CO2 would dominate the gas breakout pressure for CO2 content of 0.5% by weight.

In general pumped-well projects have nil or very little CO2 (i.e. less than 0.1% by weight). As an example, the gas breakout pressures for Heber (SIGC) and McGuiness Hills are both about 135 psia, which is only 20-30% above the vapor pressure for pure water for those reservoirs, and can be accommodated within a nominal safety factor of 35%.

### A.2 Pump power

The power required to operate a pump is primarily determined by the flowrate and lift head. In its simplest form, pump power can be estimated by Equation 3:

$$BHP = [(Q * H * \rho) / 247{,}000]/E$$

Where BHP is the brake horsepower (multiply by 0.75 to convert to kW), Q is the volumetric flowrate in GPM, H is the lift head in feet, $\rho$ is the fluid density in pounds per cubic foot, 247,000 is a constant to reconcile units, and E is the overall pump efficiency (%).

For example, a rough approximation of pump power for a pump rate of 2,000 GPM of 170°C water (density 56 lbs/cf) with a total lift head of 1500 feet and overall pump efficiency of 68% would be about 1000 BHP (750 kW).

Accurate pump power requirements for a given pump configuration can be provided by the pump manufacturer (e.g. Goulds, Lane Bowler, Baker Hughes, Schlumberger).

### A.3 Diffusivity equation applied to estimating kh and PI

The basic fluid flow equation (diffusivity equation) for porous media is derived in Earlougher (1977). For a given set of assumptions (radial, infinite acting, etc.) this equation can be simplified in oil field units to Equation 4:

$$kh = (1150 * q * B * \mu)/dp$$

Where kh is permeability-thickness in millidarcy-feet (md-ft), q is flow rate in barrels per day (Bbls/d), B is the formation volume factor of the reservoir fluid (dimensionless) - which for water at typical pumped-well reservoir conditions is essentially unity, $\mu$ is viscosity of the fluid in centipoise, and dp is difference between static and flowing pressure in pounds per square inch (psi).

The constant 1150 reconciles units in the flow equation and includes an estimate for the ratio of the radius of influence to wellbore radius of 3500. Approximations of kh are not sensitive this term because it is a log function within the diffusivity flow equation.

PI can be substituted for q/dp and the constant 12 can be substituted for 1150 to convert Bbls/d to GPM and md-ft to d-m, which results in the simplified relationship to convert PI to kh for pumped geothermal wells given in Equation 1:

$$kh\ (d - m) = 12 * PI(GPM/psi) * \mu$$

James et al. (1987) published a reasonably linear relationship between kh and PI for Heber (where PI is lbs/hr-psi and is plotted vs. kh in md-ft).