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Analysis of Geothermal Reservoir and Well Operational Conditions using Monthly Production Reports from Nevada and California

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ABSTRACT

When conducting techno-economic analysis of geothermal systems, assumptions are typically necessary for reservoir and wellbore parameters such as producer/injector well ratio, production temperature drawdown, and production/injection temperature, pressure and flow rate. To decrease uncertainty of several of these parameters, we analyzed field data reported by operators in monthly production reports. This paper presents results of a statistical analysis conducted on monthly production reports at 19 power plants in California and Nevada covering 196 production wells and 175 injection wells. The average production temperature was 304°F (151°C) for binary plants and 310°F (154°C) for flash plants. The average injection temperature was 169°F (76°C) for binary plants and 173°F (78°C) for flash plants. The average production temperature drawdown was 0.5% per year for binary plants and 0.8% per year for flash plants. The average production well flow rate was 112 L/s for binary plant wells and 62 L/s for flash plant wells. For all 19 plants combined, the median injectivity index value was 3.8 L/s/bar, and the average producer/injector well ratio was 1.6. As an additional example of analysis using data from monthly production reports, a coupled reservoir-wellbore model was developed to derive productivity curves at various pump horsepower settings. The workflow and model were applied to two example production wells.

1. Introduction

Techno-economic estimates of geothermal systems – often described as levelized cost of electricity (LCOE) or levelized cost of heat (LCOH) – usually require values for several technical reservoir and wellbore parameters including well ratio (i.e., number of producers per injector), production temperature drawdown, and production/injection well flow rates, pressures, and temperatures. These values are often difficult to accurately estimate in techno-economic estimates due to the proprietary nature of the data. To lower the uncertainty of these parameters and increase overall reliability of LCOE or LCOH estimates, we analyzed field data reported by the operators in monthly production reports (MPRs). These reports are submitted by operators on a monthly basis to federal and state agencies and contain data on well status, temperatures, pressures, flow rates, and the amount of electricity generated.

A statistical analysis was conducted on MPRs for 375 wells (196 production wells and 179 injection wells) at 19 power plants (12 binary and 7 flash plants) in California and Nevada. MPRs were obtained from the Nevada Division of Minerals (NDOM) for geothermal power plants in Nevada and from the Bureau of Land Management (BLM) for geothermal power plants with wells on federal lands in California and Nevada. The date range spans the length of operations for plants in Nevada and covers the time period 2000-2017 for plants in California.

2. Methodology

Through consent from the BLM and NDOM, the National Renewable Energy Laboratory (NREL) collected MPRs for 19 geothermal power plants in California and Nevada. Figure 1 shows the regions of study in northwestern Nevada and central-southern California.

Figure 1. Regions of study in California and Nevada.

The data were provided in spreadsheets and required preprocessing, including merging of several files for the same well and unit conversions for consistency across all wells. These files were then imported into MATLAB for processing, where the team eliminated incorrect datapoints that resulted from gauge malfunction or human entry error. A statistical analysis was then conducted to develop histograms and box-and-whisker plots for flow rate, temperature, injectivity index, and well ratio. A "best-fit" temperature drawdown line curve was calculated for binary and flash plants. The results were then compared with values and assumptions used in reservoir models and papers found in literature. The team developed a reservoir-wellbore model that uses the MPR data as input, and outputs productivity curves at various pump horsepower settings.

The box-and-whisker plots used in this study (Section 3) visualize the following statistical data: minimum or 1.5 times interquartile range below first quartile (whichever is larger, bottom whisker), first quartile (bottom of box), median (line in box), average (cross), third quartile (top of box), maximum or 1.5 times interquartile range above third quartile (whichever is smaller, top whisker), and outliers identified as lying beyond 1.5 times the interquartile range from either end of the box (dots). The interquartile range is the same as the length of the box (spread between first and third quartile).

3. Statistical Analysis of Reservoir and Wellbore Data

This section provides the results of the statistical analysis of the MPR data for 196 production wells and 179 injection wells at 19 geothermal power plants in California and Nevada. Results are presented using box-and-whisker plots, histograms, and time-series charts.

Figure 2 is a collection of plots showing statistics calculated for production and injection temperature, production flow rate, injectivity index, and well ratio. The temperature and flow rate statistics (Figures 2A and 2B) were calculated by averaging the monthly temperature and flow rate data for each well. Figure 2A shows that the average production temperatures are 304°F (151°C) for binary and 310°F (154°C) for flash plants, and the average injection temperatures are 169°F (76°C) for binary and 173°F (78°C) for flash plants. There are a few high-temperature outliers present for the binary injection temperature, potentially because these wells are reinjecting brine that bypassed the power plant. Figure 2B shows that binary facilities have an average production flow rate of 112 L/s (1775 gpm) – almost double the flash average rate of 62 L/s (983 gpm). Although a mass-based flow rate (i.e., kg/s) may provide more information (especially for flash power plants) than a volume-based flow rate (i.e., L/s), volume-based flow rates are reported here because all operators provide these data in the MPRs while only some include mass-based production data.

The injectivity index (a measure of the performance of injection wells) was calculated by dividing the injection flow rate by wellhead pressure for each month; the median value was taken for each well as a representative value. The median was used instead of the average based on approaches in other studies (e.g., Mines, 2016). The statistics for the injectivity index are shown in Figure 2C. The median values for binary and flash are about 14 L/s/bar, and 3 L/s/bar, respectively.

To calculate average well ratio, the well ratio was first calculated for each plant separately as the average of the number of active production wells divided by the number of active injection wells for each month reported. Figure 2D shows the statistics for the well ratio for all plants combined. The average well ratio for all plants is 1.6.

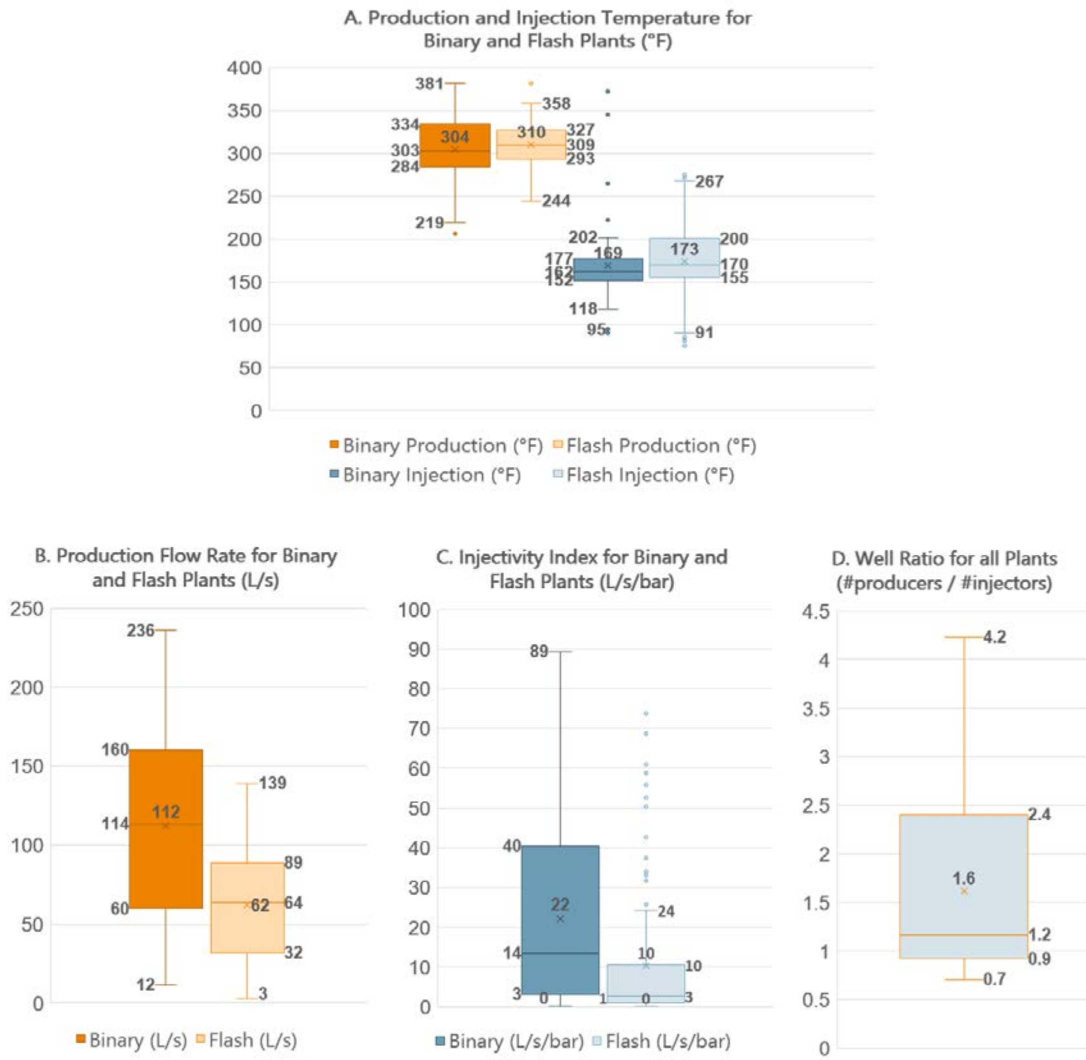

Figure 2. Summarized well data, including: production and injection temperatures (A), production flow rate (B), injectivity index (C), and well ratio (D). The box-and-whisker plot representation used is explained in Section 2.

The average lifetime production well temperature and injection well temperature for all 196 production and 179 injection wells combined are shown in histograms in Figures 3 and 4, respectively. The range and distribution of average lifetime production temperatures is fairly similar for both types of power plants. The distribution of average lifetime injection temperatures appears more to be more widely distributed for flash plants than for binary plants.

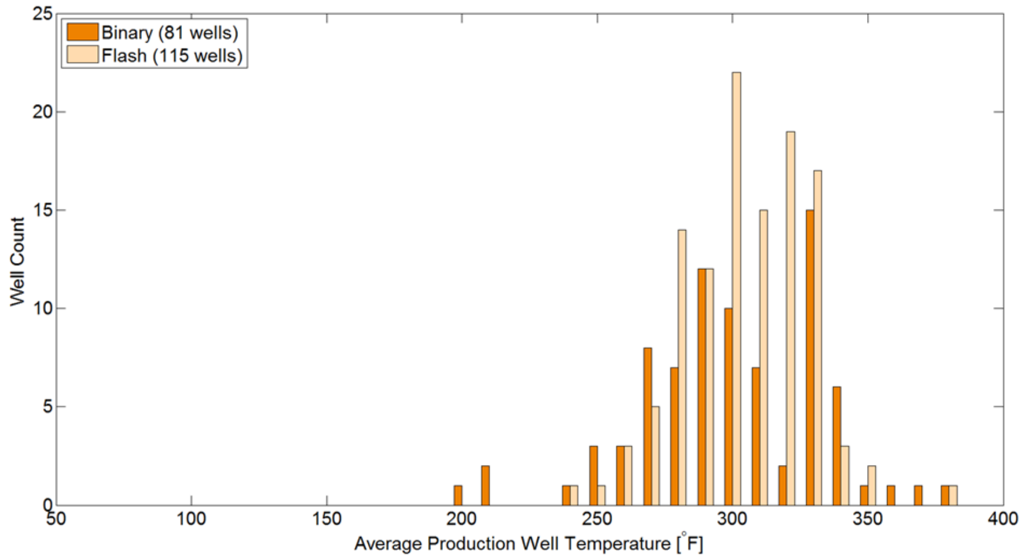

Figure 3. Average temperatures for 196 geothermal production wells, plotted by plant type. Production temperature range and distribution is relatively similar for both types of plants.

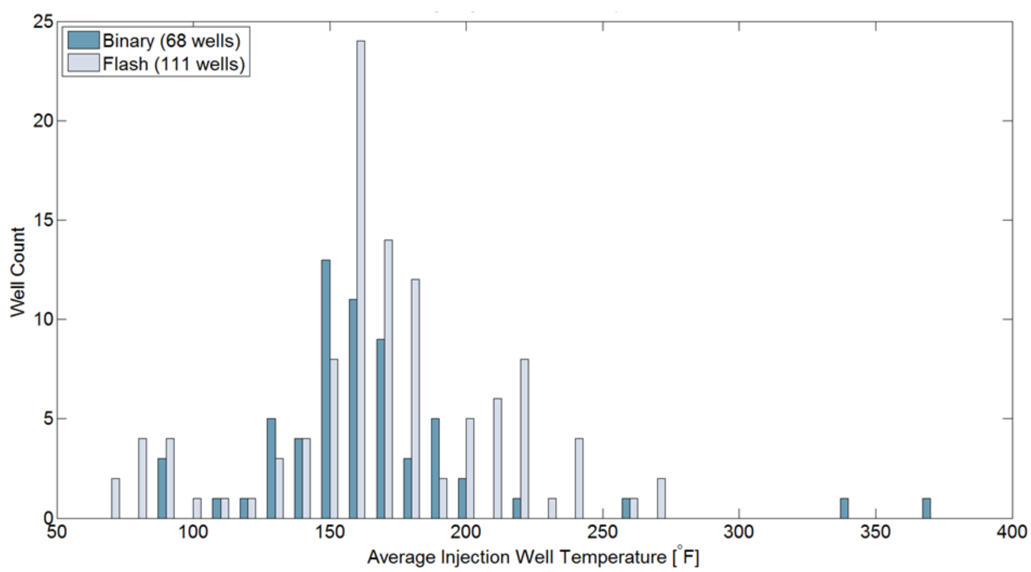

Figure 4. Average temperatures for 179 geothermal injection wells, plotted by plant type. Flash plant injection temperatures appear to be distributed more widely than binary plant injection temperatures. The same data are also shown in Figure 2A.

Figure 5 shows the normalized, yearly averaged production temperature for each well. A best-fit linear drawdown curve was estimated for both types of plants: the binary plants have an annual temperature decline rate of 0.5%, while flash plants experience a drawdown of 0.8% per year. The majority of the wells (roughly 90%) appear to follow a linear trend.

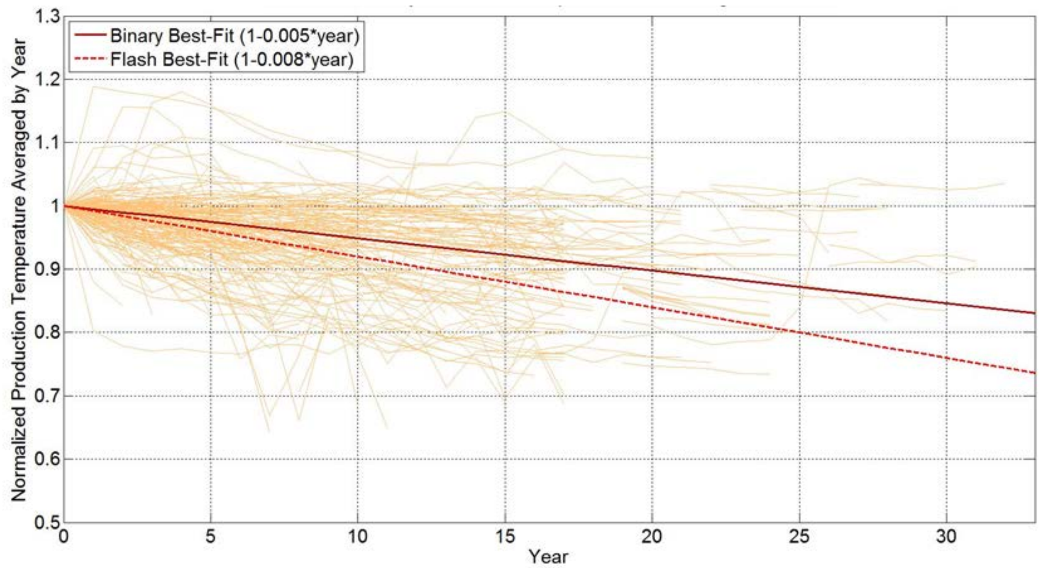

Figure 5. Normalized yearly averaged production temperature for 196 geothermal production wells and linear best-fit by plant type. The binary plants studied have an average production well drawdown rate of 0.5% per year, while flash plants production wells experience an average 0.8% yearly drawdown rate.

The monthly injection temperature stays relatively constant as shown in Figure 6. Seasonal fluctuations in injection temperature are visible for several wells. Higher reinjection temperatures are expected during the summer when the power plant efficiency is lower due to higher ambient temperatures (especially for dry-cooled condensers). Conversely, in the winter, lower reinjection temperatures are expected due to higher power plant efficiencies.

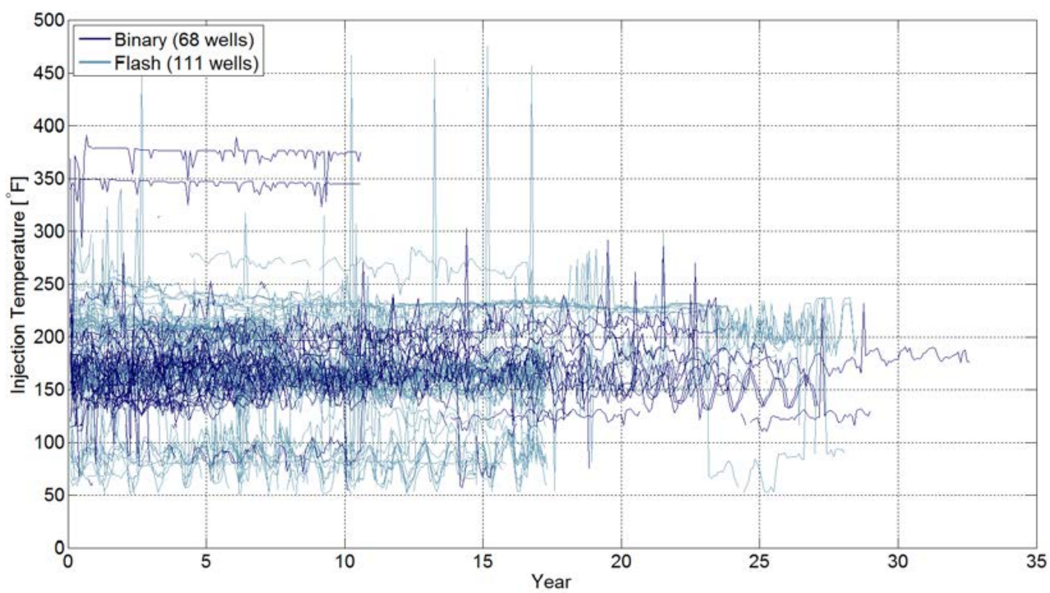

Figure 6. Monthly injection temperature for 179 injection wells. Unlike production wells, no long-term decline is present. Seasonal fluctuations are due to changes in power plant efficiency in winter vs. summer.

The average flow rate (L/s) for each production well is shown in the histogram in Figure 7. Wells from flash plants tend to have lower flow rates relative to binary facilities.

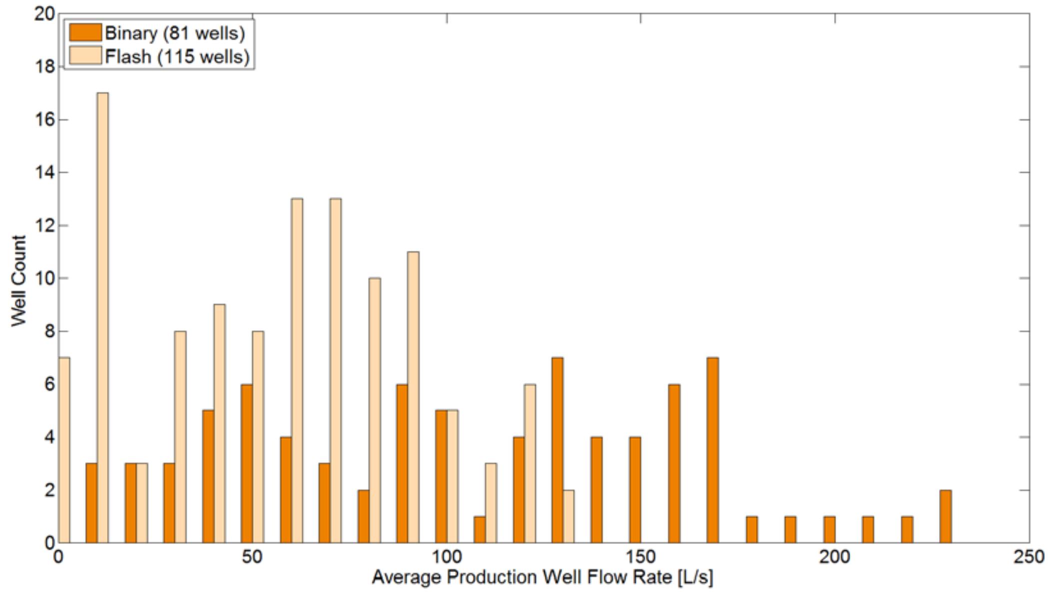

Figure 7. Average flow rates for 196 geothermal production wells, plotted by plant type. Binary facility flow rates span a wider range than flash plants, with many having higher flow rates than flash

Figure 8 shows the raw monthly flow rate data, where each orange line represents a single production well. The dashed red and solid dark red line represent the average monthly production well flow rate over time for flash and binary plants, respectively. While the average flow rate remains fairly constant for flash plants, it slowly increases over time for binary plants.

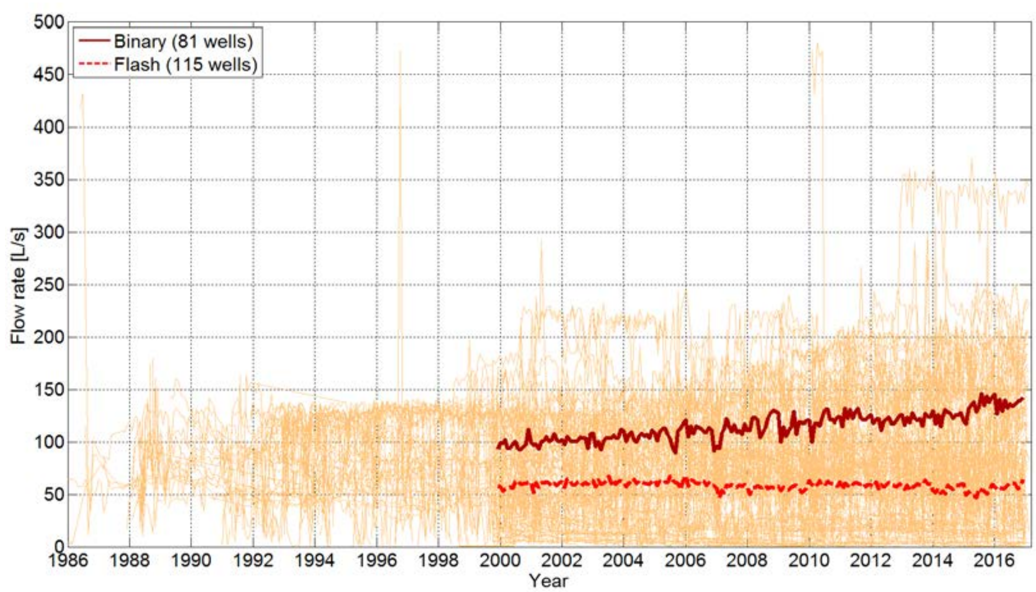

Figure 8. Flow rates over time for 196 geothermal production wells. Binary facilities have higher flow rates in general and see an increase in average flow rate over time.

4. Coupled Reservoir-Wellbore Modeling

We developed a coupled reservoir-wellbore model to derive well productivity curves at various pump horsepower settings. The workflow and model were applied to two example production wells in the McGinness Hills geothermal field (Well 28A-10 and Well 36-10). More information on this field and the two production wells in particular is provided by Norquist and Delwiche (2013) and Lovekin et al. (2016). Historical production data for these two wells are publicly available from NDOM.

The commercial software CMG Stars was used to perform these coupled reservoir-wellbore simulations for Well 28A-10 and Well 36-10 (Table 1). Results for Well 28A-10 (Figure 9) show the 1400 hp, 1740 hp, and 2300 hp pump curves provide little in the way of flow rate improvement since they overlap. The historical data indicate that the well is operating near its maximum reservoir-wellbore output. Results for Well 36-10 (Figure 10) show there is significant upside potential at higher pump horsepower settings.

Table 1. Data for wells in the McGinness Hills field (Norquist and Delwiche, 2013).

Well	Flowing Wellhead Temperature *°F*	Flowing Wellhead Pressure *psia*	Pump Depth *ft*	Static Pressure at Pump Depth *psig*	Productivity Index *gpm/psi*
28A-10	337	166	1,500	476	31.6
36-10	331	179	1,500	482	250

First, initial reservoir pressures were estimated using the static pressures at pump depth extrapolated to an average feed-zone depth. Average feed-zone depth was determined for each well using published temperature profiles (Norquist and Delwiche, 2013); a fresh water gradient (0.433 psi/ft) was used to estimate initial reservoir pressure.

Second, a permeability-thickness product for each well was calculated using each well's productivity index. Reservoir thickness was assumed to be 100 feet. Finally, pump horsepower was adjusted to history match well rates and wellhead pressures (Table 2).

Table 2. Calculated parameters and adjusted pump horsepower for history match.

Well	Midpoint of Feed Zone Depth *ft*	Estimated Reservoir Pressure *psia*	Permeability Thickness Product *md*ft*	Adjusted Pump Horsepower to history match early-mid-late period production *HP*
28-A	3150	1205	196.6E3	700-1150-905
36-10	2045	733	1550.0E3	450-650-700

The history-matched models were used to derive productivity curves for each well. Productivity curves illustrate well rates as functions of wellhead pressure. Each productivity curve is impacted by pump horsepower, which was varied from 50 hp to 2100 hp in simulations of historical and untested operating conditions. Modeling results indicate Well 28A-10 is approaching its maximum reservoir-wellbore output potential, whereas Well 36-10 output would increase significantly if operated at higher pump horsepower settings (Figures 9 and 10).

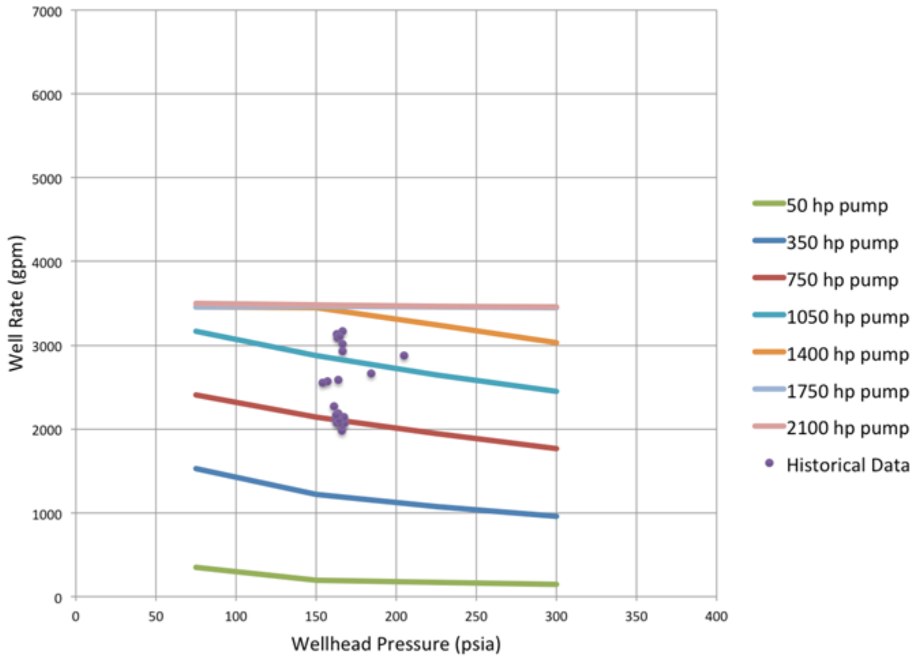

Figure 9. Well 28A-10 productivity curves at specific pump horsepower settings: 50, 350, 750, 1050, 1400, 1750 and 2100 hp. Dots represent range in historical operating conditions.

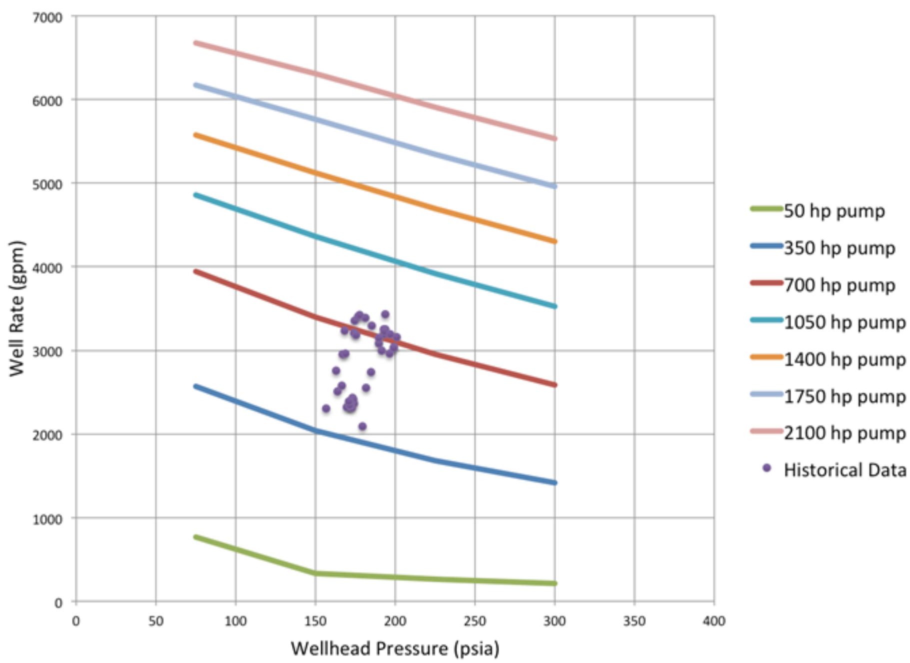

Figure 10. Well 36-10 productivity curves at specific pump horsepower settings: 50, 350, 700, 1050, 1400, 1750 and 2100 hp. Dots represent range in historical operating conditions.

5. Discussion of Results

Analysis of the production temperature data (Figures 2A and 3) shows that the average binary production temperature (304°F) is only 6°F smaller than the average flash production temperature (310°F). This temperature difference is perhaps surprisingly small given that high-temperature resources have historically been associated with flash plants and low-temperature resources with binary plants. Although not visible in the plots, the MPR data reveals that this temperature difference has decreased over the last 20 years due to a handful of binary plants with high-temperature production wells coming online recently. Advances in binary plant technology and less stringent permitting requirements may have caused a shift with developers to consider binary plants over flash plants for higher temperature resources. The recent openings of binary plants also caused the average timespan of the MPR data to be slightly shorter for binary production wells in comparison with flash production wells (20.5 years vs. 21.8 years). Hence, the flash plant production wells saw on average an additional 1.3 years of drawdown or roughly a 3°F temperature drop. When only considering 20.5 years of drawdown for flash power plants, the average flash production temperature increases from 310°F to about 311.5°F.

Even though the average well production temperatures for binary and flash plants are within a few °F, the specific (i.e. per unit of mass) energy (i.e. enthalpy) and exergy of the produced fluid will be considerably larger for flash plants in comparison with binary plants. The reason is that produced water of flash power plant wells is usually a liquid/vapor mixture at the wellhead while binary plant wells produce a pure liquid. No sufficient data were available from the MPRs to calculate values for average produced energy and exergy from binary and flash production wells.

Analysis of the injection temperature data (Figures 2A and 4) reveal a significant amount of heat left in the injected fluid, with 169°F and 173°F as average injection temperature for binary and flash plants, respectively. This heat may be suitable for direct-use applications, assuming mineral precipitation and increased decline in reservoir temperature output would not be an issue.

The production flow rate plots (Figures 2B, 7 and 8) show an average production well flow rate for binary plants twice as high as for flash plants (112 vs. 62 L/s). Active pumping with downhole pumps allow for higher flow rates at binary facilities. This technique is usually not feasible for flash plants due to challenging liquid/vapor conditions in the wellbore and more complex (and less flexible) plant operations because of the flashers. Unlike flash plants, the production flow rate for binary plants has been increasing over time. This trend could be explained by 1) power plant operators actively increasing the pumping rate for binary wells to counteract a declining reservoir temperature to avoid or limit a decline in electricity output and 2) recent production wells with high flow rates coming online at newly built binary plants, maybe reflecting new technology and/or better exploration methods.

For the subsurface parameters derived in our work (Section 3), a literature review was conducted to compare values assumed or calculated in other studies. Table 3 shows values for temperature drawdown, well flow rate, injectivity index and well ratio from our analysis and those found in literature. Units for flow rate and injectivity index can either be volume-based or mass-based. The values for these parameters obtained from literature and reported in Table 3 are kept in their original unit. While the wells we considered are only for hydrothermal systems, values assumed for Enhanced Geothermal System (EGS) resources are included in Table 3 as well. The most direct comparison is Mines (2016), which utilized data for 125 wells (vs. 375 wells in our study) from 14 power plants in Nevada dated from ~1980's - 2015. Our work used a similar dataset, with additional data for Nevada from NDOM and for Nevada and California from BLM. The results of our study and Mines (2016) are comparable, with a small difference in data. Mines (2016) used a different approach by focusing on reservoir drawdown calculated by analyzing drawdown in electricity generation, while we focused on wellhead temperature drawdown from values reported in MPRs.

In comparison with other studies, our values for temperature drawdown, injectivity index, and well ratio fall in the range of values found in literature. Production well flow rates in our study are up to four times higher than those found in other studies.

Table 3. Comparison of average subsurface parameter values derived in this study with values found in literature. Values from literature are kept in their original units.

		Temperature Drawdown (%/year)	Well Flow Rate (Various units)	Injectivity Index (Various units)	Well Ratio (#P/#I)	Comments
HYDROTHERMAL	This Study	Binary: 0.5 Flash: 0.8	Binary: 112 L/s Flash: 62 L/s	3.8 L/s/bar (median value)	1.6	Based on field data from Nevada and California
	Augustine (2013)	0	N/A	N/A	1 – 2	Simulation assumptions for sedimentary geothermal systems
	Beckers and Young (2017)	0	31.5 L/s	N/A	1	Simulation assumptions for direct-use
	Mines (2016)	Binary: 0.5 Flash: 0.6	Binary: 110 kg/s Flash: 80 kg/s	4.6 kg/s/bar	1 – 2	Based on field data from Nevada
	Mullane (2016)	N/A	31.5 L/s	N/A	N/A	Simulation assumptions for direct-use
EGS	Augustine et al. (2010)	0.3	60 kg/s	N/A	2	Simulation assumptions for electricity
	Beckers (2016)	1 - 2	30 - 70 kg/s	N/A	2 – 4	Simulation assumptions for electricity and direct-use
	Beckers and Young (2017)	0	20 - 110 L/s	N/A	1	Simulation assumptions for direct-use
	Mines and Nathwani (2013)	0.5	40 kg/s	0.4 psi per 1,000 lb/hr (=1/injectivity index)	2	Simulation assumptions for electricity
	Reber et al. (2014)	~0	30 - 80 kg/s	N/A	1	Simulation assumptions for direct-use
	Sanyal et al. (2007)	0 - 2 °C per year	2500 gpm (158 L/s)	N/A	1 – 5	Simulation assumptions for electricity
	Tester et al. (2006)	3	20 - 80 kg/s	N/A	2 – 3	Simulation assumptions for electricity

6. Conclusions

MPRs were collected, reviewed, and analyzed for 19 geothermal power plants in California and Nevada, including 196 production wells and 179 injection wells (375 total). Using field data from these MPRs, statistical analyses were conducted on several subsurface parameters including production and injection well temperature, production well flow rate, well ratio and injectivity index, for binary and flash power plants. The results presented in this paper and summarized below provide a range for these subsurface parameters. The results can be valuable for selecting values for techno-economic simulations and can decrease the uncertainty of the simulation results.

The analysis of the MPR data shows that:

- Average temperature drawdown for binary and flash plants are 0.5%/year and 0.8%/year, respectively
- Median injectivity index for all plants is 3.8 L/s/bar. These values are in the range of values found in literature
- Average production well flow rates for binary and flash plants are 112 L/s and 62 L/s, respectively, higher than typically assumed in literature
- Average well ratio is 1.6, which is in the range of values found in literature
- Average production temperature is 304°F (151°C) for binary plants (for an average of 20.5 years of production data), and 310°F (154°C) for flash plants (for an average of 21.8 years of production data).
- Average injection temperature is 169°F (76°C) for binary plants, and 173°F (78°C) for flash plants.

A difference of 6°F (3°C) between the average production temperature for binary and flash plants is surprisingly small. This temperature difference has decreased over the last two decades due to recent construction of binary facilities with high-temperature production wells. An average injection temperature around 170°F suggests significant amount of heat is still present in the reinjected brine for many injection wells. This heat may be suitable for direct-use applications assuming mineral precipitation and accelerated reservoir temperature decline would not become an issue.

A method for determining well productivity curves using MPR data has been developed and demonstrated for two production wells.

Possible future work includes incorporating additional MPRs from other geothermal power plants, and analyzing other parameters such as electricity generation by plant, impact of dry-cooled condensers vs. wet-cooled condensers, and heat extraction by plant based on temperature decline between production and injection wells.

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