The Estimated Costs as a Function of Depth of Geothermal Development Wells Drilled in Nevada

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ABSTRACT

Expected well costs can be a major factor in whether companies obtain financing due to expense and moderate success rates of drilling. Well permitting records are reported by state agencies, and well production from individual wells within producing areas are reported monthly (in NV) so that one can determine, in retrospect, which of the permitted wells actually led to geothermal production and power generation. A companion paper (Shevenell, 2012, this volume) compiles and evaluates geothermal well records submitted to the Nevada Division of Minerals, and estimates the success rates of geothermal wells drilled in Nevada since the early stages of exploration in the 1970s and 1980s, through construction of the power plants currently in existence in northern Nevada. This paper uses that information to estimate the minimum expected costs associated with drilled wells and production per MW, assuming well depths are a dominant factor in determining costs. Because depths are not the only factor determining power plant costs, costs noted here are likely minima.

Introduction

This paper uses well records compiled by the Nevada Division of Minerals to estimate the range of drilling costs for Nevada geothermal wells. The well depth data are available from the early stages of exploration in the 1970s and 1980s, through construction of the power plants and are used to calculate total and average well depths and associated minimum costs by producing area. It is common to hear comments related to the "success rate" of geothermal

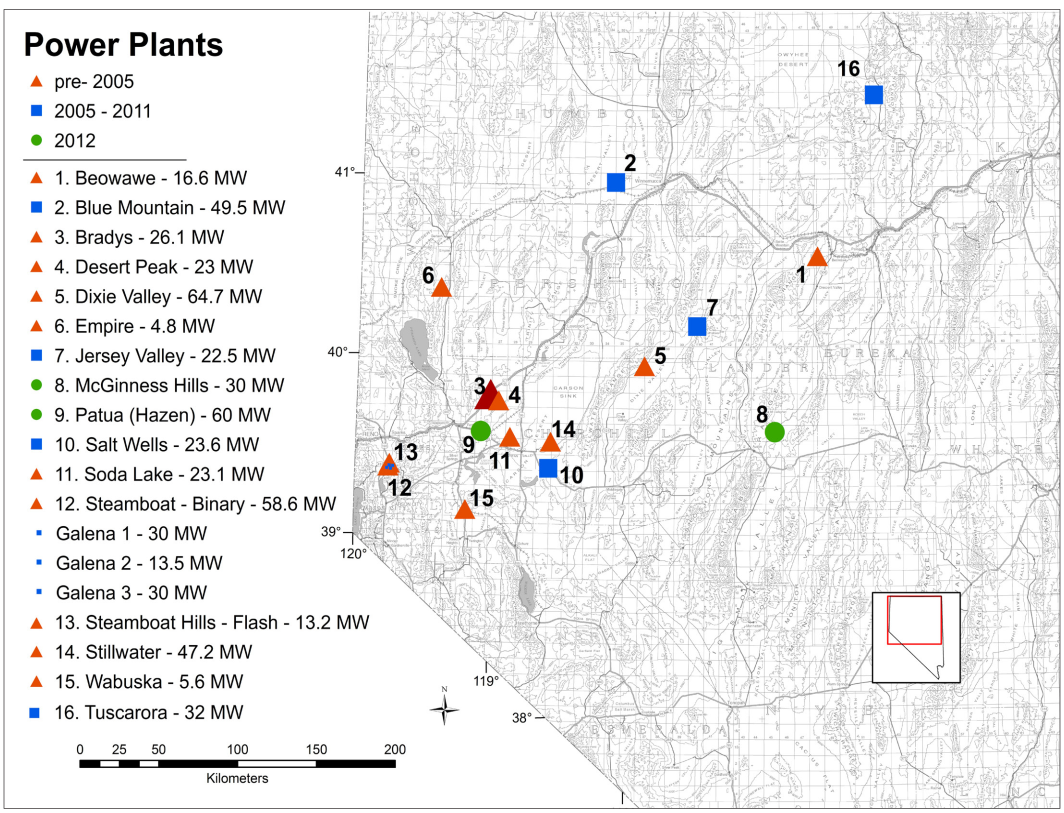

Figure 1. Location of existing and planned power plants in Nevada. Steamboat-binary consists of 6 separate power plant units that have a combined generating capacity of 137 MW. Only the three new plants constructed since 1992 are listed separately under the binary category.

wells in the context of overall development costs and financing, with numbers on the order of 50-75% commonly used to estimate the success rate (typically in reference to production wells). These assertions are often in the context that individual production wells are on the order of $3-5 million, with the implication that even unsuccessful wells could cost a developer up to $5 million. Such risk-benefit scenarios may be difficult to sell to investors, certainly if the first few wells drilled fall into this category. As reported by Hance (2005) "… debt lenders (commercial banks) will also require 25% of the resource capacity to be proven before lending any money. This means that all early phases of the project have to be financed by equity. The actual cost of these phases rises quickly as time goes on. Up-to-date cost information is often site-specific and tends to be held proprietary by researchers and consultants. … few articles thus address geothermal development costs in a comprehensive way and those tend to be based on outdated data."

Given the paucity of reliable cost data, this paper attempts to determine the relative costs of geothermal well drilling using publicly-available data and empirically-derived cost-depth relationships. All drilled wells are considered in this analysis, including preliminary and exploratory wells, because each helps define an individual resource, which, in turn, should help increase the success rates of future wells drilled for production and injection. Hence, the costs of the preliminary and exploratory wells need to be considered in evaluations of power generation field expenses. Well completion data are available from the Nevada Division of Minerals (DOM) for the nine currently producing power plant areas (that may include one or more commercial units each) in Nevada using available data through 2010 (e.g., more than nine areas are producing, but the more recently constructed power plants do not yet have sufficient data for evaluation). These data are currently being compiled and quality checked for inclusion into the National Geothermal Data System (NGDS) to be made publicly and freely available through several user interfaces.

Background

Figure 1 shows the locations of the operating and planned power plants in Nevada as of mid-2012 showing current nameplate capacity.

A brief description of each of the new power plants constructed since 1992 and the relationship between the number of permits and drilled wells can be found in Shevenell and Zehner (2011) and Shevenell (2012, this volume). Earlier descriptions are found in Garside et al. (2002) and in the annual Nevada Mineral Industry reports (http://www.nbmg.unr.edu/dox/mi/XX.pdf, where XX are the last two digits of the individual year from this annual report series, which was first published in 1979 for 1978 information).

Methods

An overall summary of results from all sites is provided, and a comparison of site observations appears in Shevenell (2012; this volume) for numbers of wells and depth, depth drilled per MW, and number of wells drilled per MW. Permitted domestic wells are excluded from the analysis since few currently-producing power plant areas have nearby and are not relevant to the analysis here. Two time periods were evaluated for each producing plant in Shevenell (2012): pre-commissioning (including all wells permitted for exploration up to and including plant construction), and post-commissioning (including wells drilled to better define and expand the resource). The pre-commissioning data are presented here, based on results in Shevenell (2012), because these have the most complete depth data. Many depths (up to 53%, average of 35%, Table 5 of Shevenell (2012)) are missing from the post-commissioning well records, making it an unreliable data set for cost evaluations predicated on depth. Datasets for each power producing operation (Steamboat being considered as one area/operation) are evaluated to determine the costs of wells drilled. Drilling depth and cost data were compiled from the published literature and one well in NV for determination of cost estimates using empirically determined relationships with depth determined with data reported by Hance (2004), Augustine et al. (2006), Mansure (2005) and unpublished data from one well drilled at Bradys, NV, which has detailed cost by foot of penetration data. Most data obtained from Augustine et al. (2006) were compiled from the *Joint Association Survey on Drilling Costs* (1976-2000) from oil and gas wells. Note that Bloomfield and Laney (2005) also report well drilling cost estimates, but mostly using the same data reported by GeothermEx (Klein et al., 2004), and are thus, not reported separately.

In each set of Results tables, the well costs are noted by geothermal field for average numbers and depths of wells per field. The wells investigated were subdivided as follows: E for Exploration, I for Injection, O for Observation and P for Production. In some cases the production and injection wells are lumped in the original data as Industrial wells, in which case those wells are assumed to be production wells. It is assumed that wells would have been labeled as injection if indeed they were because injection well permitting requires a unique form distinct from the other permitted wells. The following were categorized as exploration wells: exploration, test, stratigraphic test, thermal gradient and geothermal wells.

All cost data from published historical and unpublished (Bradys) data sources were escalated to 2012 dollars using a calculator available on the US Bureau of Labor Statistics: http://data.bls.gov/cgi-bin/cpicalc.pl?cost1=500%2C000.00&year1=2003&year2=2010. All calculations and results are made using these adjustments to 2012 US dollars.

Table 1. Total feet drilled by area for production and injection wells.

	# P	# I	#P+I	P feet	I feet	ft (P+I)	Ave ft P	Ave ft I
Beowawe	2	1	3	11,165	5,927	17,092	5,583	5,927
Bradys	11	1	12	18,328	3,123	21,451	1,666	3,123
Desert eak	3	1	4	13,465	3,192	16,657	4,488	3,192
Dixie Valley	10	7	17	94,091	59,747	153,838	9,409	8,535
San Emidio	3	2	5	1,423	1,106	2,529	474	553
Soda Lake	1	1	2	8,489	4,306	12,795	8,489	4,306
Steamboat	13	2	15	15,587	4,321	19,908	1,199	2,161
Stillwater	4	1	5	8,173	2,920	11,093	2,043	2,920
Wabuska	1	3	4	500	2,460	2,960	500	820
Average	5.3	2.1	7.4	19,025	9,678	28,703	3,761	3,504
Stdev	4.7	2.0	5.6	28,770	18,824	47,407	3,418	2,503

Results

General Summary

Because Steamboat has several different power plants, which often use wells interchangeably (either continuously or sporadically), the Steamboat area is considered in total, and not by individual power plant unit. Numbers of wells and depths by well category appear in Table 1.

Depth data are considerably more complete for the pre-commissioning set of wells than for the post commissioning wells. Only two wells had no reported depths: 1 exploration well at Desert Peak and one exploration well at Steamboat. Hence, general conclusions are not adversely impacted by lack of available data in the pre-commissioning data set.

Table 1 and Figure 2 summarize the total and average feet drilled per industrial well type at each geothermal area along with the averages for the nine sites in Nevada. The P+I well category is included because it is assumed that well types are similar and costs can be estimated based on the empirical relationships presented below.

With the exception of Dixie Valley, there are far more exploration than development wells (P+I) drilled per area, and more feet per E well drilled than feet per P or I wells (Figure 3). This statistic is reasonable because it is generally more prudent to drill lower cost exploration and confirmation wells to define the resources before investing in a smaller number of expensive production and injection wells. However, the large numbers noted for Beowawe, San Emidio and Steamboat appear excessive. Most of the 55 exploration wells drilled at Beowawe were drilled in the 1960s and 1970s by Chevron, however 15 were drilled by Getty Oil Company near the same time as the production wells were drilled in the early 1980s indicating this may have been a new phase of resource definition, although Beowawe Power LLC drilled the final production wells in advance of the plan commissioning. Forty exploration wells were drilled prior to the development phase at Beowawe. San Emidio had 59 exploration wells drilled in the late 1970s by Chevron, but USG Nevada (mostly) drilled the production and injection wells in the late 1980s, having approximately a decade hiatus following the Chevron abandoned exploration efforts. At Steamboat, 52 exploration wells were drilled by a variety of different (at least 12) entities including the U.S. Geological Survey in the 1940s and 1950s. The conclusion that can be made from these data is that where multiple entities occupied the sites over several decades, the exploration wells tended to be numerous, perhaps because subsequent entities/companies did not fully utilize the pre-existing data at those three, particular sites (Beowawe, San Emidio and Steamboat).

Injection wells are typically fewer than production wells (Figure 3), except at Wabuska, yet all three of the wells depicted in this figure were either plugged and abandoned or shut in. No wells are used for injection at Wabuska, and all water is discharged to the surface. Typically, a power production operation requires fewer injection than production wells (Figure 3).

Figure 2 and XXft2 illustrate the total number of feet drilled by each type of well (P, I, O, E) by area, with Figure 4 omitting the Dixie Valley data to allow for easier viewing of the other sites whose total feed drilled is up to half as much as at Dixie Valley, in part due to the deeper resource at Dixie Valley. Except for the shallowest resource at Wabuska, fewer feet of exploration well depths were drilled at Dixie Valley than the other areas in an absolute sense, and far fewer in a relative sense given Dixie Valley's greater depth.

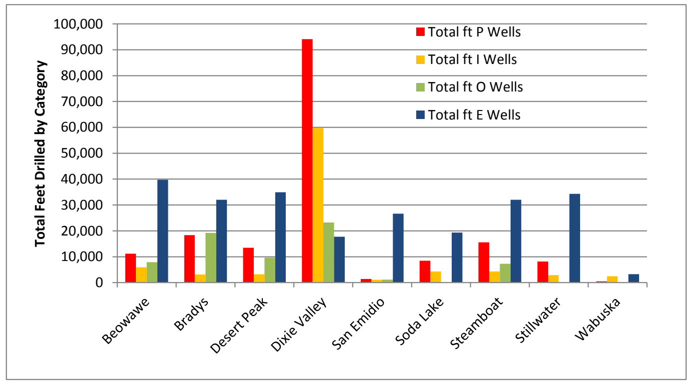

Figure 2. Total feet drilled by category (P, I, O and E) for each of the nine geothermal areas in Nevada discussed in this paper.

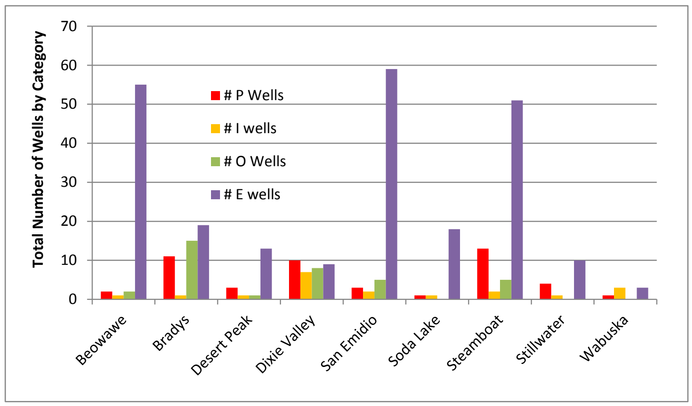

Figure 3. Total number of wells drilled by category (P, I, O and E) for each of the nine geothermal areas in Nevada discussed in this paper.

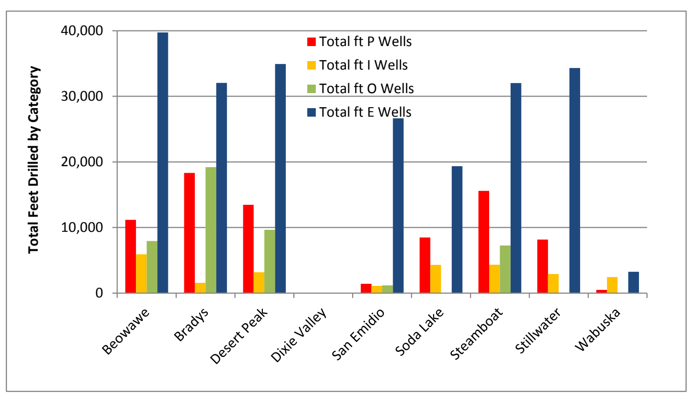

Figure 4. This figure is a duplicate of Figure 2 noting total feet drilled by category (P, I, O and E) for the eight geothermal areas in Nevada, omitting the deepest reservoir (Dixie Valley) in order to better view the depth relationships at the other sites.

From these figures it is obvious that the total feet drilled by exploration holes is greater, to far greater, than double the feet drilled per production or injection well (i.e., more information is gathered more cheaply during earlier phase exploration using less expensive wells). The E wells are typically much less expensive ($15 per foot based on Klein et al., 2004; or $18.70/ft in 2012 dollars), and are reported separately. However, the author believes this estimate of cost per foot is likely to be too low in most cases where various complications can be expected. The O wells were often converted to a P or I well (15% of them) so the cost of those wells could be either closer to the $18.7/ft or the empirical costs depending on how the well was completed, which is typically not known. Hence, the P and I wells are the focus of the cost estimates of development but a hybrid estimate of the cost of the O wells is provided (assuming 15% of the feet cost $18.7/ft, and 85% cost the values calculated with the empirical relationships).

Table 2. The number of feet per well type drilled.

	ft per P	ft per I	ft per E	ft per O
Beowawe	5,583	5,927	722	3,966
Bradys	1,666	3,123	1,687	1,280
Desert Peak	4,488	3,192	2,686	9,641
Dixie Valley	9,409	8,535	1,970	2,906
San Emidio	474	553	451	235
Soda Lake	8,489	4,306	1,075	0
Steamboat	1,199	2,161	628	1,453
Stillwater	2,043	2,920	3,432	0
Wabuska	500	820	1,081	0
Average	3,761	3,504	1,526	2,165
Stdev	3,418	2,503	1,013	3,138

These average feet per well type in Table 2 multiplied by the number of wells per type per area are used below with the empirical relationships to estimate cost of wells used in production operations (P and I). “Success rates” of the various well types by geothermal area by depth and number are presented in Shevenell (2012).

Regressions

Regressions were calculated for the various datasets obtained from the literature in various combinations to determine the best fit for the available data. Data were plotted directly to test different models, but it was found that plots of the log(Cost $US) versus depth provided the best fit to the data. Augustine et al. (2006) also reported cost data as log values for the same reason. Table 3 lists results of assembled data sets and some combinations of model fits (exponential, linear, polynomial and power) using the log(Cost $US) versus depth relationships. Note that one set of data notes all data minus the values from Tester, which are largely based on data from the oil and gas industry, and are typically lower than those obtained in the plots showing geothermal well costs by depth from the other sources of information. The best R^2 value for each data set is noted in bold in the table. Neither the exponential or linear models were the best fit for any of the data, although some showed good correlations with the data (Bradys, Mansure, and Augustine data). None of the R^2 values are particularly good using the GeothermEx data (Klein et al. (2004)), although the power function best matches the complete data set. The power regression provided the best fit of the data for some of the data combinations, whereas the polynomial regression provided the best fit for the other combinations. Although the two model fits were typically fairly close to one another when comparing the R^2 values, the equations for the models for the ones in bold were used in further analyses.

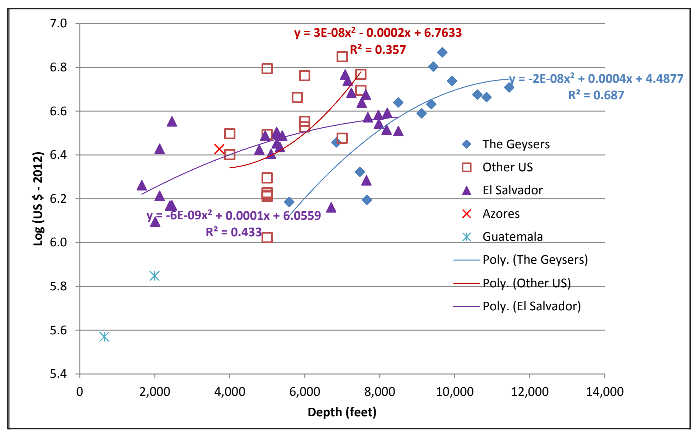

Figure 5. Log Cost in dollars (2012) versus well depths for data reported in the GeothermEx Pier Report (Klein et al., 2004) by geographic area.

Table 3. R^2 values for four types of regression analyses noting the best fit for each data set in bold.

		Exponential	Linear	Polynomial	Power
All Data		0.486	0.492	0.556	**0.567**
All Data	minus Tester	0.552	0.552	0.609	**0.624**
Bradys		0.843	0.852	**0.946**	0.920
GeothermEx	Geysers	0.641	0.638	**0.687**	0.666
GeothermEx	El Salvador	0.418	0.418	**0.433**	0.432
GeothermEx	Other US	0.332	0.336	**0.357**	0.309
GeothermEx	All Data	0.442	0.444	0.473	**0.514**
Mansure	All	0.715	0.729	0.785	**0.832**
Mansure	1970s	0.736	0.755	0.902	**0.909**
Tester	1,800-10,000 ft	0.969	0.965	**0.992**	0.850
Tester	1,800-20,000 ft	0.994	0.994	**0.995**	0.909

If the GeothermEx data are plotted by geographic region, markedly different regression equations are obtained (Figure 5) due to the large scatter in data values. This plot illustrates that the GeothermEx R^2 using all data is relatively low compared to other datasets.

Other variability is not explicitly accounted for in the data sets. For instance, the data presented by Mansure et al. (2005) show a distinct difference in costs from the 1970s to the 1980s (Figure 6), with costs shifting lower in the 1980s. Figure 6 shows the regression equation for the 1970s data set, which is similar to the full data set, although with a slightly better correlation coefficient ($R^2 = 0.909$ versus 0.832). The equation for all Mansure data is

$$\log(\$\ US - 2012) = 3.882(\text{Depth})^{0.0558} \quad R^2 = 0.832$$

Similarly, there are other sources of variability in the data sets. Figure 7 plots the log costs versus well depth for all data compiled for this paper and shows that the Augustine data consistently predict lower costs than the other data. The Augustine data is largely from oil and gas drilling results, whereas the other compiled data are for wells drilled for geothermal purposes. Hence, the Augustine data will provide a lower bound to well costs by depth for the geothermal wells investigated here.

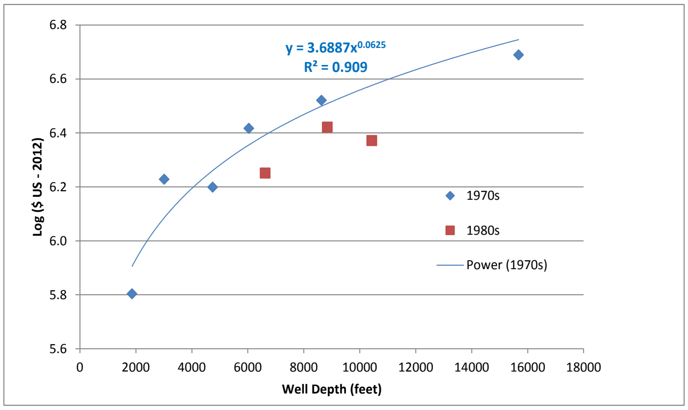

Figure 6. Plot of well depths versus costs summarized from Mansure et al. (2006) illustrating the difference in costs between the 1970s and 1980s data, with the regression equation noted being for the 1970s data.

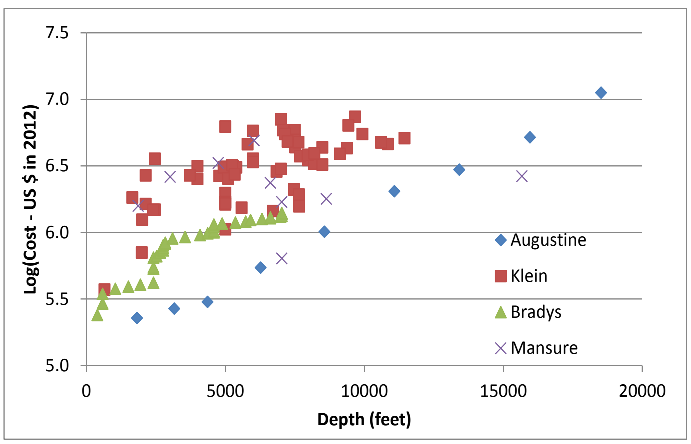

Figure 7. Plot of log costs versus well depth for all data compiled for this paper.

The best fit power function of all data plotted in Figure 7 is

$$\log\ (\text{US\$-2012}) = 3.5077\ (\text{Depth})^{0.0679}\ R^2 = 0.5673$$

The R^2 is relatively low when all data are used in the regression analysis due to significant data scatter as a result of variations in timing and location of data collection. Because of the scatter, three different regressions are used to estimate costs of production wells at the Nevada geothermal areas to provide a range of costs possible. As noted, the Augustine costs are likely too low, and the Bradys costs are only from one well, but are likely representative of the types of conditions drilled in Nevada geothermal areas. The Klein data are from multiple locations, some of which are close to the Bradys values, but most indicate higher costs.

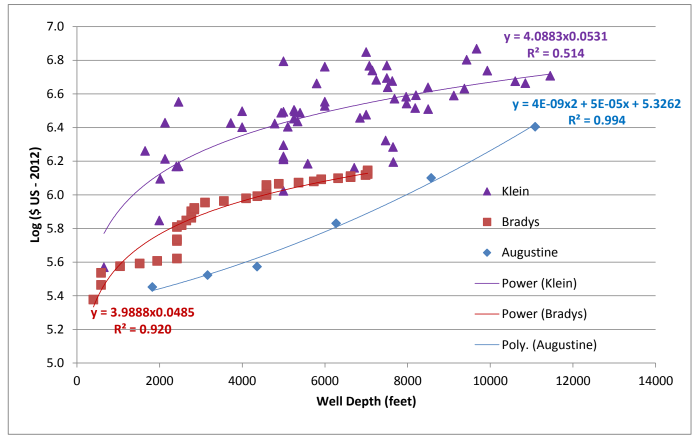

Figure 8. Plot showing three possible equations to calculate costs of production wells by depth.

The Augustine et al. (2006) best fit polynomial for the data is

$$\text{Log (Cost US-2012)} = 4\text{E-}09D^2 + 5\text{E-}05D + 5.3262 - R^2 = 0.994$$

The Klein et al. (2004) best fit power equation for the presented data is

$$\text{Log (Cost US-2012)} = 4.0883D^{0.0531} - R^2 = 0.514$$

The Bradys (unpublished) best fit power equation for the data from one well during which cumulative costs were recorded is

$$\text{Log (Cost US-2012)} = 3.988D^{0.0485} - R^2 = 0.920$$

where D is well depth.

Note that the Augustine data fit is best because the data were smoothed by averaging depths over specific depth intervals (Figure 8).

Klein et al. (2004) developed the following function from statistical analyses of historical drilling costs, showing that the depth of the well is a major (although not only) parameter explaining a well's overall cost:

$$\textit{Drilling cost (in US\$)} = 240{,}785 + 210 \times \textit{(depth in feet)} + 0.019069 \times \textit{(depth in feet)},\ R^2 = 0.558.$$

Hence, a significant portion of the cost variability of geothermal wells evaluated in their study can be attributed to well depth. Of course, actual costs of wells may vary significantly from this due to a variety of other factors such as diameter, lost circulation, rock structure, hardness, and permeability, etc. (Hance, 2005). For the purposes of the current work in Nevada and comparisons (or minimum average costs) among sites, the three depth relationships (using log(Costs)) are used to estimate costs as a function of depth because depth is the only factor available from the evaluated data set and the regressions appear to match the data better than the relationship reported by Klein et al. (2004). All estimated costs are minima because factors impacting costs other than depth (material cost variability, dates of drilling, penetration rates, diameter, site assessments, etc.) are not considered here.

Estimated Well Costs

Well costs are estimated using the three regression equations noted in the previous section for Augustine, Bradys, and Klein

(Table 4). This table lists the estimated cost by the three methods for both P and I wells separated, using the average depth of either the P or I wells at each site in Nevada resulting in an estimate of per well cost of industrial (P and I) wells. Dixie Valley is the most expensive to drill given its greater depth than the other reservoirs. However, other factors impact the estimated costs in Table 4 such as success rate because the calculations use average depths of either P or I drilled at each site, without consideration of which ones were actually used. The calculations were done in this manner to estimate the total project cost because some wells at these areas are either not successful or not used in the ultimate generation facility, yet the costs for drilling them were still incurred. See Shevenell (2012, this volume) for success of wells drilled at these sites (i.e., how many were actually used per total depths drilled).

Table 5 lists the estimated costs per industrial well per project multiplying the numbers noted in Table 4 by the number of the P or I wells drilled at the site (whether they are used or not in the production operation).

Costs for the four major categories of wells drilled at each site are noted in Table 6, with the P and I costs using the average of the three regression equations and the average well depth multiplied by the total number of the wells per category drilled at each area. The E costs are likely low and used the $18.70 per foot (Klein et al., 2004) value to estimate costs of drilling the total depths of all E wells at each site. The costs of the observation (O) wells are a hybrid of the previous two calculations. Approximately 10% of the wells initially drilled as observation wells were converted to P or I wells after drilling (Shevenell 2012, this volume). Therefore, an estimate of costs for these O wells was obtained by calculating the average regression equation values used for P and I multiplied by 20%, with 90% of the noted cost being that of an E well. Other estimates could be made because well diameter is not one of the data values available in this work, and that would be useful to better determine which category the drilled O wells fit into relative to being either an industrial or exploration well. Table 6 also lists total estimated drilling costs for P, I, O and E by geothermal area, adjusted to 2012 dollars. These values do not include geologic, geochemical, or geophysical surveys and resource assessment work required to site the wells.

An important statistic is how much is the expected cost per MW of power produced, which is estimated for the nine sites in Nevada in Table 7, along with the estimated cost per foot depth of reservoir. These data are also plotted on Figure 9. Although Dixie Valley produces from the deepest reservoir, it was neither costliest from the perspective of depth nor number of MW produced (Figure 9). Beowawe, which produces from the next deepest reservoir, was one of the least costly to drill when considering both reservoir depth and numbers of MW produced.

Table 4. Average cost per well at each site using the three regression equations for P and I wells.

	Augustine	Bradys	Klein	Augustine	Bradys	Klein
	Cost per Ave	Cost per Ave	Cost per Ave	Cost per Ave	Cost per Ave	Cost per Ave
	P well drilled	P well drilled	P well drilled	I well drilled	I well drilled	I well drilled
Beowawe	$537,000	$1,151,000	$2,907,000	$580,000	$1,200,000	$3,048,000
Bradys	$263,000	$520,000	$1,152,000	$332,000	$781,000	$1,850,000
Desert Peak	$428,000	$994,000	$245,000	$336,000	$793,000	$1,880,000
Dixie Valley	$1,415,000	$1,647,000	$4,417,000	$1,108,000	$1,539,000	$4,082,000
San Emidio	$224,000	$239,000	$468,000	$227,000	$262,000	$521,000
Soda Lake	$1,094,000	$1,534,000	$4,064,000	$413,000	$967,000	$2,371,000
Steamboat	$247,000	$422,000	$905,000	$284,000	$615,000	$1,400,000
Stillwater	$279,000	$593,000	$1,341,000	$321,000	$748,000	$1,760,000
Wabuska	$225,000	$247,000	$486,000	$234,000	$333,000	$688,000

Table 5. Total cost per area using the three regression equations for P and I wells by multiplying the total number of wells by the per well costs in Table 4.

	Augustine	Bradys	Klein	Augustine	Bradys	Klein
	Total Cost	Total Cost	Total Cost	Total Cost	Total Cost	Total Cost
	P Wells	P Wells	P Wells	I Wells	I Wells	I Wells
Beowawe	$1,074,000	$2,303,000	$5,815,000	$580,000	$1,200,000	$3,048,000
Bradys	$2,897,000	$5,721,000	$12,680,000	$332,000	$781,000	$1,850,000
Desert Peak	$1,283,000	$2,983,000	$7,348,000	$336,000	$793,000	$1,881,000
Dixie Valley	$14,150,000	$16,470,000	$44,175,000	$7,753,000	$10,780,000	$28,570,000
San Emidio	$673,000	$717,000	$1,404,000	$453,000	$524,000	$1,042,000
Soda Lake	$1,094,000	$1,534,000	$4,064,000	$413,000	$967,000	$2,371,000
Steamboat	$3,205,000	$5,489,000	$11,760,000	$567,000	$1,230,000	$2,798,000
Stillwater	$1,115,000	$2,371,000	$5,365,000	$321,000	$748,000	$1,757,000
Wabuska	$225,000	$247,000	$486,000	$703,000	$1,000,000	$2,064,000

Table 6. Estimated cost of all P, I, E and O wells drilled by area along with total drilling costs for the area (cost per well times number of wells per area are presented in this table). Average of the Klein, Augustine and Bradys values by well type by area are presented for P and I.

	Costs P	Costs I	Costs E	Costs O*	Total Drilling Costs
Beowawe	$3,064,000	$1,610,000	$743,000	$369,000	$5,790,000
Bradys	$7,100,000	$988,000	$599,000	$1,140,000	$9,830,000
Desert Peak	$3,870,000	$1,003,000	$653,000	$419,000	$5,950,000
Dixie Valley	$24,900,000	$15,700,000	$332,000	$1,140,000	$42,100,000
San Emidio	$931,000	$673,000	$498,000	$131,000	$2,230,000
Soda Lake	$2,230,000	$1,250,000	$362,000	$0	$3,840,000
Steamboat	$6,820,000	$1,530,000	$599,000	$418,000	$9,370,000
Stillwater	$2,950,000	$942,000	$642,000	$0	$4,530,000
Wabuska	$319,000	$1,260,000	$61,000	$0	$1,640,000

* O costs are calculated at 15% of P based on depth + 85% of E costs per foot

Discussion

Costs per depth and MW are plotted by increasing order of cost in Table XXCostDis. Error bars are not shown to avoid clutter, but they are fairly large ranging from 40 to 80% for the P wells (average =66%) and 48 to 80% for the I wells (average = 72%)

Table 7. Reservoir depths, production capacity in MW at commissioning and estimated cost per MW and for depth (ft) of the reservoir at the nine geothermal areas investigated in Nevada.

	Reservoir Depth (ft)	Year Online	MW at commis-sioning	Cost per MW	Cost per ft depth of Reservoir
Beowawe	8207	1985	13.9	$417,000	$705
Bradys	1654	1992	28.7	$342,000	$5,940
Desert Peak	5501	1985	9.5	$628,000	$1,080
Dixie Valley	9509	1988	55.7	$756,000	$4,430
San Emidio	1694	1987	2.1	$1,071,000	$1,320
Soda Lake	1100	1987	3.5	$1,098,000	$3,490
Steamboat	3023	1986	16.5	$567,000	$3,100
Stillwater	2982	1989	6.8	$666,000	$1,520
Wabuska	860	1984	0.4	$3,827,000	$1,901
Average			15.2	$1,041,000	$2,610
Standard Deviation			17.5	$1,076,000	$1,760

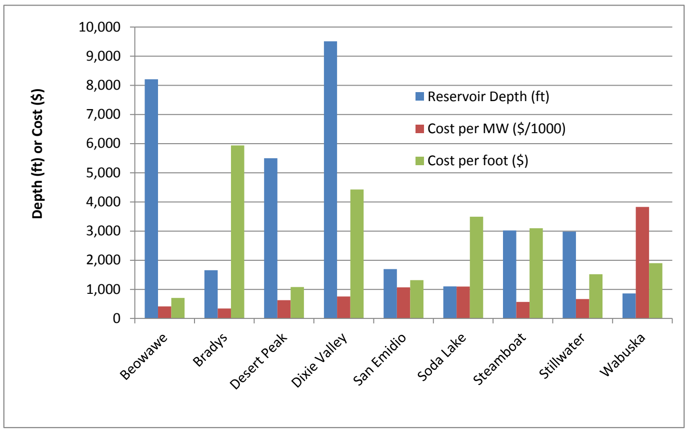

Figure 9. Plot of Nevada producing fields showing reservoir depth, costs per MW (in 1,000s) and cost per depth of reservoir.

when calculating the standard deviation of estimated costs from the three regression expression used in this work. Bradys is the costliest by foot, but the least expensive by the standard of MW capacity. Cost per MW at existing power production facilities have an estimated range from a $341,000 to 1.09 million (omitting Wabuska), averaging $693,000±$275,000 per MW in drilling costs.

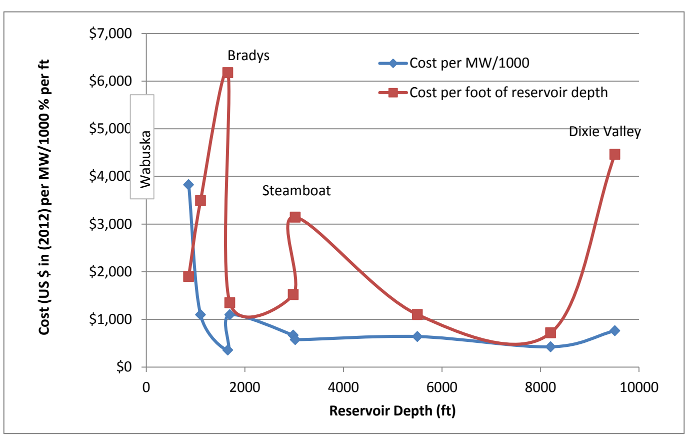

Figure 10. Estimated costs of drilling in terms of dollars per MW capacity and dollars per foot depth of the reservoir.

Wabuska (shallowest reservoir depth on Figure 10) appears to be the most expensive cost per MW, in part because the data are divided by a small number (0.4) of MW, and those costs were likely not actually realized because a full MW was not developed. However, this anomaly also points to the issue that there may be an economies-of-scale issue that should drive power projects. Dixie Valley, while not the least expensive, has a considerably lower estimated cost even though it is a much deeper resource (near 10,000 ft vs 500 ft at Wabuska and 1,694 ft at San Emidio). However, Dixie Valley has the largest MW production of any facility (except for the Steamboat complex), and its costs per MW are in the median range of costs. Bradys, which has the most expensive cost per foot of reservoir, is the least costly when viewed relative to the MW capacity constructed. Hence, expensive drilling costs (as a function of reservoir depth) may not translate to overly expensive power production costs, which can be seen for all sites (except Wabuska), but in particular for Bradys, Steamboat, and Dixie Valley, where costs per MW are relatively low, and costs per foot of reservoir depth are relatively high.

Many wells were drilled in the time period for which data are presented here. It is likely that with advances in the understanding of geothermal systems since the 1970s and 1980s, greater successes and relatively lower costs can be attained today by drilling fewer, but more successful wells. Table 8 shows the number of P and I wells used at each of the power plants at the time of commissioning, the average costs of P and I wells using the three regression expressions presented in this paper, and the total cost of drilling the given P and I wells divided by the MW at the time of commissioning. As such, the last column in Table 8 lists the estimated cost of production and injection wells per MW for the sizes of the power plants noted in the tables. Excluding Wabuska, the estimated cost requirements for industrial well drilling per MW ranges from approximately $190,000 to $790,000 if all wells used in production operations were drilled successfully, with no unsuccessful P or I wells. The average cost is $506,000 ± $217,000 assuming all wells would be successful, which is optimistic given this has rarely been the case in the past.

Table 8. Estimated costs averaging the three regression expressions presented in this paper and totaling by the number of wells used to obtain costs per MW.

	MW at commis-sioning	P used	I used	Cost per P Well	Cost per I Well	Cost of P+I Wells per MW
Beowawe	13.9	2	2	$1,530,000	$1,610,000	$452,000
Bradys	28.7	4	3	$645,000	$988,000	$193,000
Desert Peak	9.5	3	2	$1,290,000	$1,000,000	$621,000
Dixie Valley	55.7	7	6	$2,490,000	$2,240,000	$555,000
San Emidio	2.1	1	4	$310,000	$336,000	$795,000
Soda Lake	3.5	--*	1	$2,230,000	$1,250,000	--*
Steamboat	16.5	4	3	$525,000	$766,000	$266,000
Stillwater	6.8	1	4	$738,000	$942,000	$662,000
Wabuska	0.4	2	0	$319,000	$419,000	$1,490,000

*Original production well must have stopped being used by the time records for production began in 2002 as none drilled prior to commissioning are recorded in production files.

A typical breakdown of costs of completing a geothermal power production facility from beginning to end has been presented by Hance (2005), pictured in Figure 11 below. If this breakdown is a reasonable distribution of costs and the estimates here are reasonable industry averages given a range of costs for different systems developed, with 23% of total project costs being for P+I drilling, then projects might be expected to range from $835,000 to $3.4 million per MW, if all industrial wells are drilled successfully.

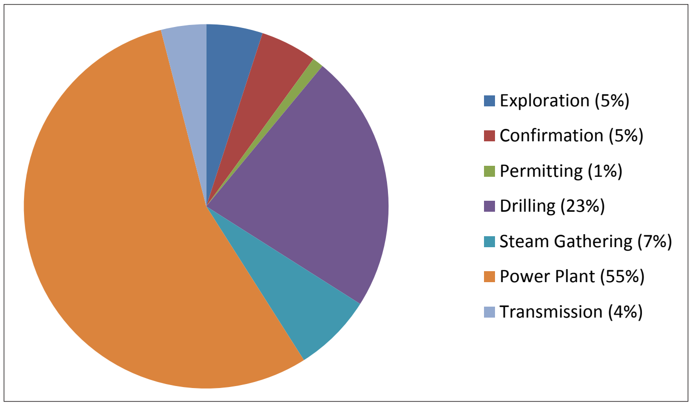

Figure 11. Typical cost breakdown of geothermal power projects (after Hance, 2005).

Summary

The actual costs of geothermal wells drilled in Nevada are not currently readily available, but some estimates are made to evaluate ranges of costs. Clearly, the data can be presented, viewed and interpreted in a number of different ways depending on how many of which types of wells are included in the analysis, and the relative cost of money through time. Given that a comprehensive database of costs of drilling geothermal production and injection wells under actual field conditions is not currently available, this paper present a first order estimate of such expected costs based on the number of wells, reservoir depth, and initial MW produced from nine sites in Nevada. These data were used along with three separate regression equations to estimate well drilling costs in "typical" geothermal development projects in Nevada. Some observations from the calculations are that:

- Expensive drilling costs (as a function of reservoir depth) may not translate to overly expensive overall power development costs, which can be seen for all sites (except Wabuska), but in particular for Bradys, Steamboat, and Dixie Valley, where costs per MW are relatively low, and costs per foot of reservoir depth are relatively high.
- Although counterintuitive, the data indicate that deeper reservoirs might produce power at lower cost per MW than shallower reservoirs, likely because temperatures are hotter resulting in more MW per production well, but this factor was not explicitly considered in the current analysis.
- Projects might be expected to range from $835,000 to $3.4 million per MW, if all industrial wells are drilled successfully.
- Because not all production and injection wells drilled in Nevada were successful before plant commissioning, the drilling cost was estimated using all drilled wells (successful or not), and these estimates translate to per development project costs attributable to industrial well drilling of $1.6 to $42 million, (high is Dixie Valley), depending on reservoir depth and the number of unsuccessful wells (which are included in the analysis)
- Similarly, drilling costs per MW were estimated using all drilled wells (successful or not) and indicate costs could range from $341,000 to $1.1 million per MW based on the example cases presented in Nevada.
- Not explicitly included in the analysis are cost variability expected from variations in temperature, drilling conditions, rock type, material costs (cement, drill string and casing), labor costs, location (e.g., mobilization costs), among many other factors.

Statistics presented are not a reflection of the current operator's success rate, or any company's success rate given that multiple entities conducted exploration drilling operations prior to the final company actually constructing a power plant. Perhaps if exploration and development projects are more cohesive in the future, costs may be lowered.

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