Design and Implementation of Steam Supply for the Western Geopower Unit 1 Project at the Geysers Geothermal Field, California

S. K. Sanyal[1], R. C. Henneberger[1], E. E. Granados[1], M. Long[2], and K. MacLeod[2]

[1]GeothermEx, Inc., Richmond, California, USA
mw@geothermex.com
[2]Western GeoPower Corporation, Vancouver, B.C., Canada
kmacleod@geopower.ca

Keywords

The Geysers, steam field, power capacity, Western GeoPower, deliverability

ABSTRACT

This paper presents the case history of the first significant expansion of the installed power capacity in two decades at The Geysers steam field (California), which has been producing commercial electric power for nearly 50 years. Western GeoPower Corporation is constructing a 35 MW (net) power plant at The Geysers, where the generation capacity today has declined to about 900 MW from its peak of 1,800 MW in 1987. A 62 MW (gross) plant was operated at the Western GeoPower site from 1979 to 1989 but was shut down because of a rapid decline in well productivity. The development of a new 35 MW plant at this site has become possible today because: (a) a long production history and a large amount of resource data are available; (b) a substantial infrastructure exists at the site; and (c) the augmented injection in The Geysers field with treated municipal effluent over the last decade has sharply reduced well productivity decline. All four production wells drilled to date for this expansion have proven commercial; three of the four wells have shown much higher productivity than is typical for The Geysers field today, the fourth one being about average. These positive results can be attributed to judicious well targeting and drilling based on the analysis and modeling of the drilling and production histories from the field, significant recovery of the static reservoir pressure over the past decade, and the adoption of an efficient power plant design. The future performance of this project is expected to be attractive because the new plant size is much smaller than the original one at this site, augmented injection over the last decade has sharply reduced the rates of decline in reservoir pressure and well productivity and has diluted the gas content in steam. The technical basis for designing and implementing this expansion program are discussed in the paper.

Background

This paper presents a case history of expansion of power capacity at The Geysers, which has been producing commercial electric power for nearly 50 years. This expansion consists of a 35 MW (net) power plant (WGP Unit 1) being constructed by Western GeoPower Corporation. The field produces "dry" steam; this reduces both capital and operating costs of a power project compared to those in liquid-dominated fields. This cost reduction is possible because no steam separators are needed and injection of condensed steam requires very few injection wells. Power has been generated continuously at The Geysers since 1960, the present generation level being about 900 megawatts. Figure 1 shows the presently known

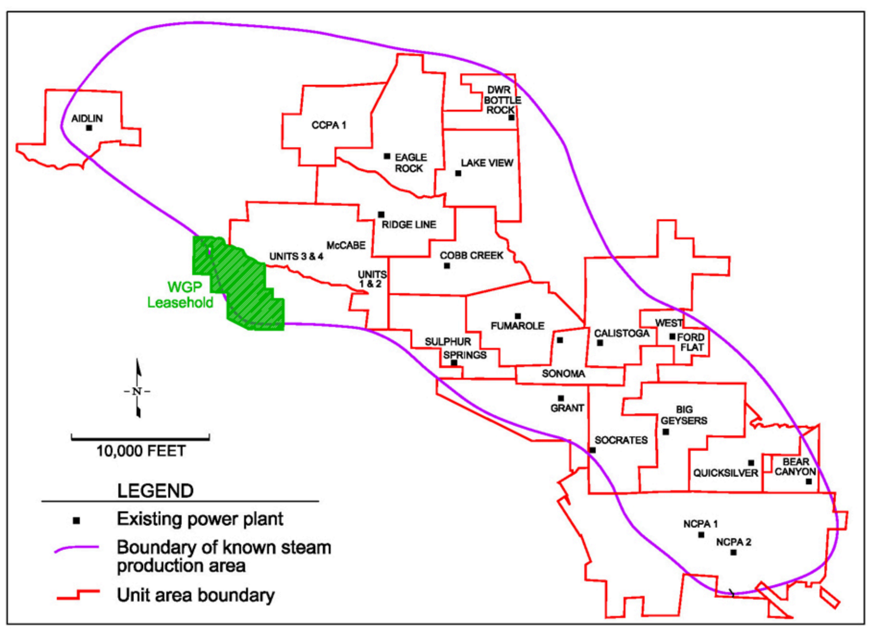

Figure 1. Historically dedicated areas within The Geysers Geothermal Field.

boundaries of the field and the historical boundaries of the areas dedicated to various power plant units (shown in red).

At its height in 1987, total net generation at The Geysers was about 1,800 MW, but by then, due to the unusually lucrative economics of power generation at The Geysers in the 1980s, the field had become over-developed. This led to a faster decline in well productivity than was sustainable economically, and to a large extent technically. The decline in well productivity could no longer be compensated for by drilling make-up wells because of the declining power price at the time (Sanyal, 2000). Figure 2 presents the production and injection history at The Geysers over the last five decades.

The uppermost plot in Figure 2 shows monthly steam production in tonnes; the middle plot shows the monthly condensate injection in tonnes; and the lowermost plot shows the injection-to-production ratio.

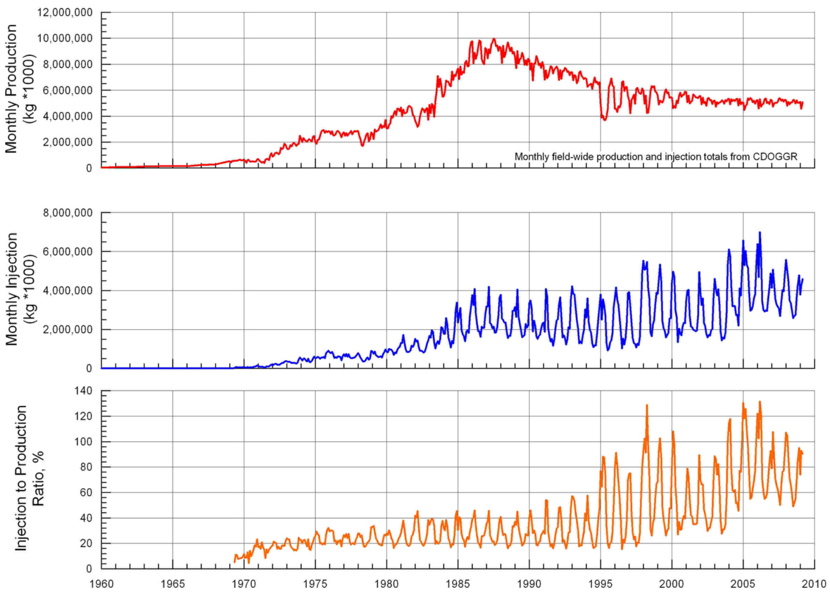

Figure 2. Historical Production and Injection Data for The Geysers.

The rapid rate of well productivity decline experienced during 1987-1995 was arrested by reducing the overall generation level at The Geysers and augmenting injection into the reservoir. Until 1997, the only fluid injected into the reservoir was the condensed steam from the power plants (about 20% to 25% of the produced steam mass) and minor amounts of water from surface run-off and water wells, the total injection amounting to 30% to 35% of the produced steam mass (Figure 2; lowermost plot). By the end of 1997 treated municipal effluent was being piped in from outside the reservoir to augment injection. At present over 80% of the annual average produced steam mass is replaced by injection (Figure 2; lowermost plot). This has sharply reduced the rate of decline in reservoir pressure, and well productivity decline has eased conspicuously, from as high as 20% to 30% per year at its worst (in 1989) to nearly zero today. For example, Figure 3, a plot of the monthly steam production rate (tones per month) from The Geysers field, shows that since 2004, there has been essentially no declination in steam rate.

Therefore, power generation at The Geysers has become attractive again.

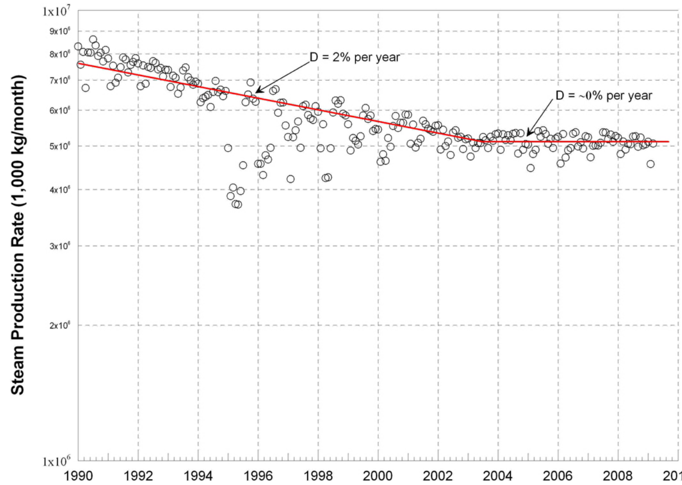

Figure 3. Recent History of Total Steam Production Rate from The Geysers Field.

The WGP leasehold (formerly referred to as the "Unit 15 leasehold") covers 567 acres and lies within the presently known boundary of the field (Figure 4).

A commercial power plant of 62 megawatt (gross) capacity, known as P.G. & E. Unit 15, operated at this leasehold from 1979 to 1989; Figure 4 shows the well-head locations, subsurface courses of the wells, and steam entry points for all wells drilled for the Unit 15 project. It is now recognized that the Unit 15 plant was oversized for the available resource, as was the case for several other power plants installed at The Geysers prior to 1989. As a result, the wells supplying the Unit 15 power plant experienced an unduly rapid initial decline in productivity. For this reason and various economic and contractual issues, the plant was shut down and dismantled, and the wells were plugged and abandoned.

A new geothermal power development at the WGP leasehold has several attractive attributes. A long production history and a large database of resource information are available from the leasehold, minimizing the resource-related risks typical of a new geothermal development. A substantial infrastructure still exists intact at the site (for example, roads, drilling pads, power plant site, sumps, transmission line, etc.); this reduces the capital cost of development of a new power generation project. Reservoir pressure under the leasehold has significantly recovered by now because of three factors: (a) decline in overall generation level at The Geysers, (b) absence of production from the leasehold for 20 years, and (c) a large increase in the fraction of produced mass being injected. Therefore, the initial well productivity at this site has proven to be higher and well productivity decline as well as pressure decline are expected to be lower, than they were when the plant was shut down.

Historical Well Productivity Characteristics within the WGP Leasehold

Figure 5 shows the total rate of production (in kilo-pounds per hour) from the Unit 15 wells over the years of operation of Unit 15.

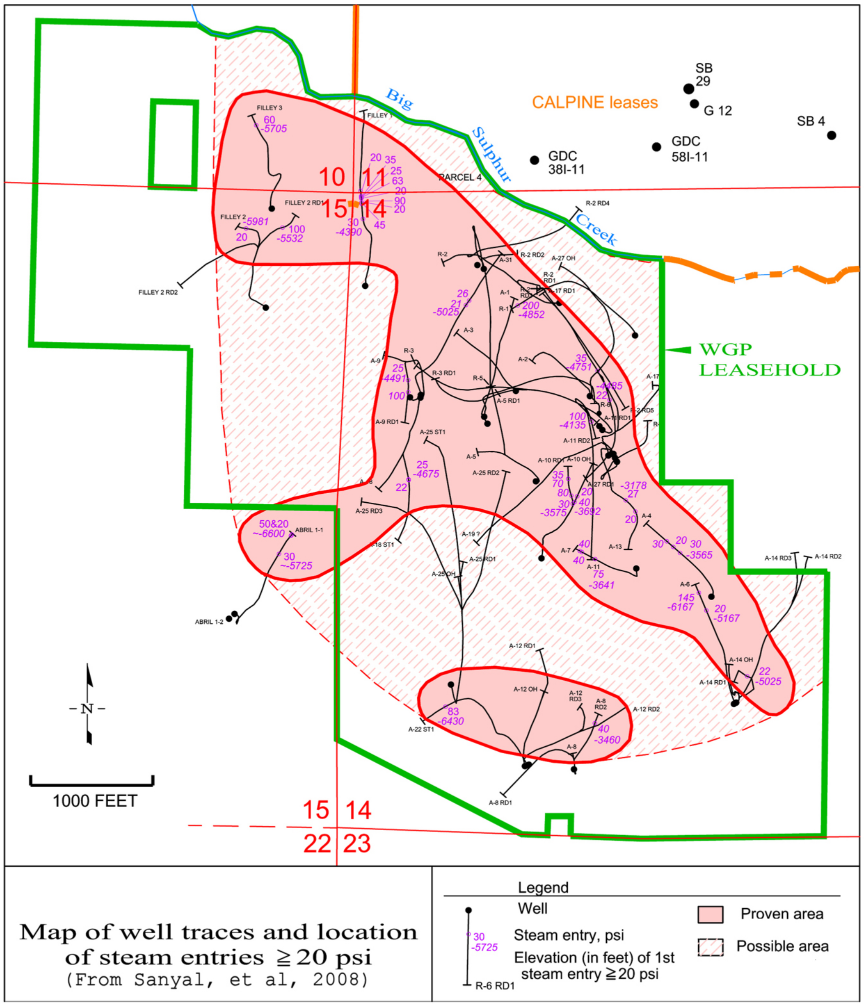

Figure 4. Map of Well Traces and Location of Steam Entries ≥ 20 psi.

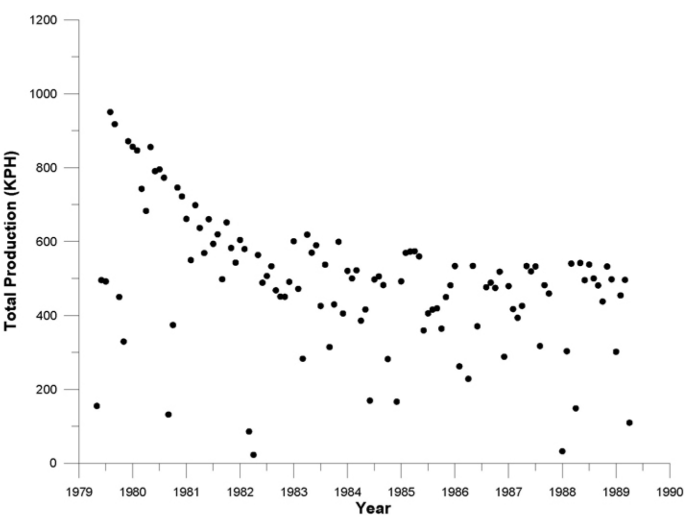

Figure 5. Total Flow Rate History of Unit 15 Wells.

It shows that this total production underwent a rapid decline from its inception in 1979 to about 1984, when production leveled off. The decline in production rate generally reflects the decline in static reservoir pressure. Figure 6 shows a plot of the static wellhead pressure at a shut-in well (GKI Rorabaugh 1) just outside the WGP leasehold (about 500 feet to the east). A continuous decline in static wellhead pressure, from 450 psia to 200 psia, is evident over the 1979-1989 operating period of the Unit 15 plant.

The influence of a declining static wellhead pressure on well productivity can be quantified by invoking an equation in common use in the natural gas industry (Sanyal et al, 1989):

$$W = C\left(p_s^2 - p_f^2\right)^n, \tag{1}$$

where W is steam production rate from a well, C is a parameter of the well, p_s is static wellhead pressure, p_f is flowing wellhead pressure and n is another parameter of the well termed the "turbulence factor." The value of n generally lies between 0.5 and 1.0. The values of n and C for a well can be estimated from the results of deliverability testing.

From Equation (1) it is clear that the steam flow rate from Unit 15 would have declined at a fixed flowing wellhead pressure. In reality, however, the average well productivity of the Unit 15 wells remained nearly unchanged during Unit 15's operation, as shown in Figure 7, overleaf, which shows the average production rate per well as well as the number of active wells. This happened because, while the static wellhead pressure declined, flowing wellhead pressures were gradually reduced from about 180 psia initially to 100 psia by 1989. Equation (1) implies that as p_s declines it is possible in theory to maintain W constant by reducing p_f. Furthermore, the total steam production required at a power plant can also be maintained by drilling make-up wells even as individual well productivity declines. This combination of reducing the flowing wellhead pressure and drilling make-up wells kept the total flow rate from the Unit 15 leasehold relatively constant from 1984 until the plant was shut down in 1989.

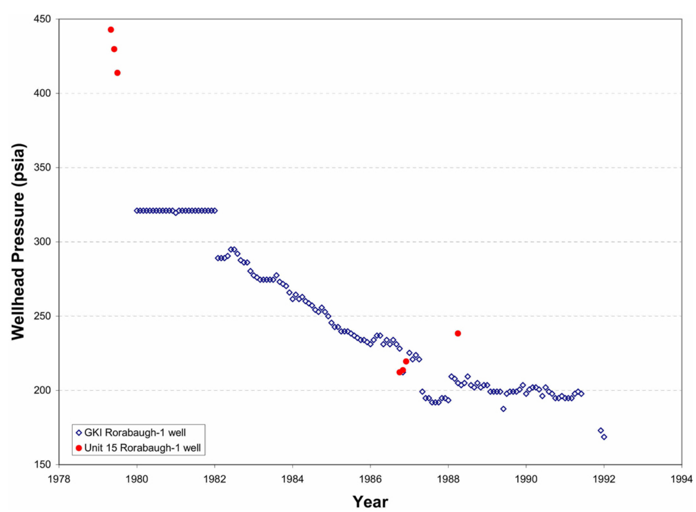

Figure 6. Static Wellhead Pressure History in the Unit 15 Area (From Sanyal, et all., 2008).

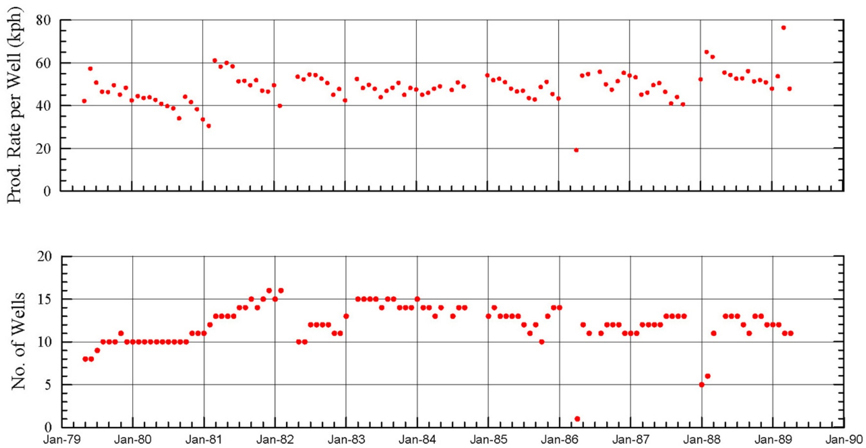

Figure 7. History of Average Production Rate per Well Unit 15.

Recent Drilling Results

Four new production wells have been drilled and tested for this project. Table 1 summarizes the main results from the testing of these wells, named as WGP-1, WGP-2, WGP-3 and WGP-4. Figure 8 shows the surface location, subsurface course, and steam entry points for each new well.

Table 1. Status of Development Drilling.

Well Name	Total Measured Depth (feet)	Total Vertical Depth (feet)	Initial Capacity (MW)*		Static Wellhead Pressure (psig)	C	n
			Gross	Net			
WGP-1	8,410	8,364	10.0	9.1	284	50.7	0.72
WGP-2	9,935	9,567	2.6	2.4	284	0.0017	1.52
WGP-3	9,801	9,665	7.0	6.3	295	28.16	0.74
WGP-4	7,605	7,493	9.1	8.3	295	47.66	0.71
		Totals:	28.7	26.1			

*For 87 psia wellhead pressure, and steam requirements of 16,130 lbs/hour/MW (gross) or 17,743 lbs/hour/MW (net).

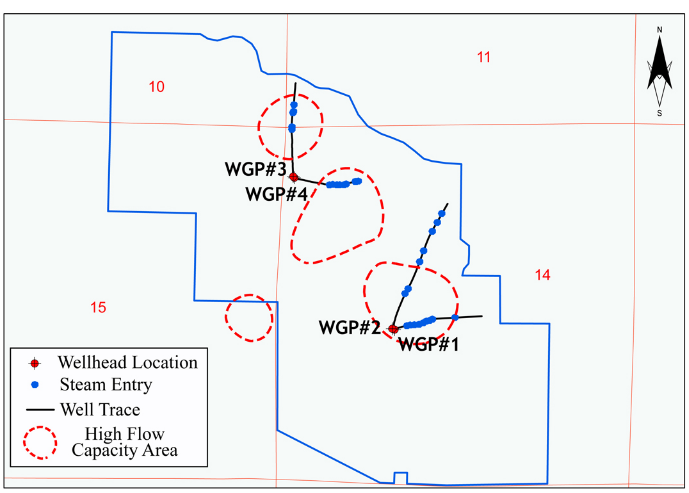

Figure 8. Well Locations and High Flow Capacity Areas, Western GeoPower Unit 1.

Table 1 shows the static wellhead pressure, C value and n value estimated for each well based on the results of testing the new wells. As seen in Table 1, wells WGP-1, WGP-2 and WGP-4 all have similar values of C and n, indicating similar production characteristics, while well WGP-2 has a spurious value of n (beyond the expected range of 0.5 to 1.0) and C. Well WGP-2 could not reach the intended target because of various drilling problems; the selection of drilling targets is discussed later. An average wellhead pressure of 284 psia has been estimated for wells WGP-1 and WGP-2. For wells WGP-3 and WGP-4, the value of the static wellhead pressure has been estimated at 295 psia. Figure 9 shows the deliverability plots from which the values of n and C were estimated for each well; the deliverability plot for all wells but WGP-2 are parallel indicating the spurious nature of well WGP-2.

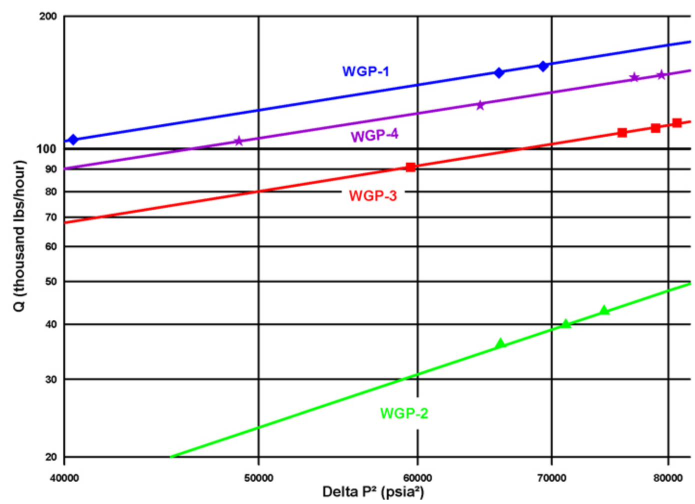

Figure 9. Well Deliverability Plots.

Power capacity of the wells was estimated by taking into account plant design conditions, which called for a minimum wellhead pressure of 87 psia. Given this condition, the maximum initial steam flow rates from wells WGP-1, WGP-2, WGP-3 and WGP-4 are estimated at 161,000 lbs/hour, 42,000 lbs/hour, 112,000 lbs/hour and 147,000 lbs/hour, respectively. The power plant specifications call for a steam requirement of 16,130 lbs/hour per MW (gross) or 17,743 lbs/hours per MW (net) at a flowing wellhead pressure of 87 psia. Using these steam requirement values, the maximum initial power capacities of the wells are estimated as shown in Table 1. Figure 10 shows the estimated MW (net) power capacity versus the flowing wellhead pressure for each of the four wells.

Analysis of Well Productivity Characteristics

As regards well productivity, well WGP-1 appears to be the most prolific well drilled at The Geysers in the past two decades, with well WGP-4 being of only slightly lower capacity than WGP-1. Well WGP-3 is also one of the most productive wells drilled in the field

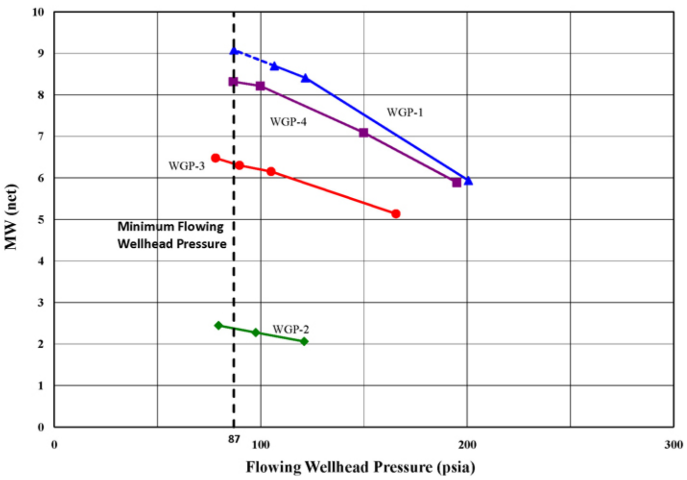

Figure 10. Western GeoPower Unit 1 Well Test Results.

in recent years, whereas well WGP-2 represents a well productivity level commonly encountered today at The Geysers. Figure 7 shows that the average production rate per well supplying the Unit 15 plant during 1979-1989 was 30,000 to 60,000 pounds per hour, considerably lower than the productivity of three of the four new wells. The reasons for this drilling success are discussed below.

One of the reasons for low average productivity of the Unit 15 wells was that some of those wells had a 9 5/8-inch "tie-back" casing cemented inside the 13 5/8-inch production casing, which reduced the diameter of the near-surface wellbore. Table 2 shows the reservoir flow capacity ("kh") and skin factor values of 11 Unit 15 wells, all of which are now plugged and abandoned. Table 2 shows that 5 of these wells had excellent flow capacities (greater than 85,000 md-ft), and the remaining 6 wells had reasonably good flow capacities compared to typical wells at The Geysers. However, all 11 wells showed positive "skin factor" values (Table 2) indicating the existence of well damage. These wells could have produced at higher rates if well damage could have been prevented or rectified. Given that the new wells were drilled such as to avoid any type of well damage, their production rates are expected to be higher. Furthermore, the present static reservoir pressure at the WGP leasehold (about 290 psia) is higher than it was when the Unit 15 was shut down (about 200 psia); this should also lead to higher flow rates. Finally, the turbine inlet pressure is much lower and efficiency much higher for the new plant, which allows for a higher power capacity per well.

Table 2. Reservoir Flow Capacity and Wellbore Skin Factor Values of Abandoned Unit 15 Wells.

Well	Flow Capacity (md-ft)	Skin Factor
Rorabaugh 1	23,700	3.3
Rorabaugh A-1	89,100	0.9
Rorabaugh A-4	27,400	4.3
Rorabaugh A-9	85,500	5.6
Rorabaugh A-10	111,000	3.1
Rorabaugh A-11	21,000	3.7
Rorabaugh A-13	94,800	1.5
Rorabaugh A-14	20,300	1.8
Rorabaugh A-17	20,500	5.2
Rorabaugh A-18	36,400	2.4
Rorabaugh A-19	98,400	1.2

Finally, the new wells were drilled into the high flow capacity areas (Figure 8) we had identified from the high reservoir capacity values (Table 2) and the actual flow rates demonstrated during the operation of Unit 15. Therefore, the combination of careful well targeting, better well design, judicious drilling to avoid any well damage, the existence of a higher static reservoir pressure today, adoption of a lower turbine inlet pressure, and a more efficient plant design explains the unusual success of the drilling program so far.

The total net initial power capacity from these wells (Figure 10) is estimated at 26.1 MW, which represents 74.6% of the initial plant capacity of 35.0 MW (net). It should be noted, however, that experience at The Geysers shows that when a plant is put on line the productivity of wells undergo 10% to 30% decline within a few weeks before stabilizing and exhibiting the slower long-term productivity decline trend ensues (estimated at 0% to 3% per year at present). This initial decline in well productivity before stabilization is caused by transient pressure behavior in the reservoir, including pressure interference between the wells. Assuming an average 20% decline before stabilization, the four completed wells represent a total stabilized flow capacity of 20.9 MW (net), or 5.22 MW (net) per well. Therefore, the 35.0 MW (net) plant can be expected to be supplied initially by 7 active wells.

Well Productivity and Pressure Decline Forecast

Figure 11 presents a forecast of average well productivity with time for the planned generation capacity of 35.0 MW (net) for the first five years of plant operation and 32.5 MW (net) thereafter, assuming base-case and optimistic scenarios of an initial annual harmonic decline rate in well productivity of 3% and 1%, respectively.

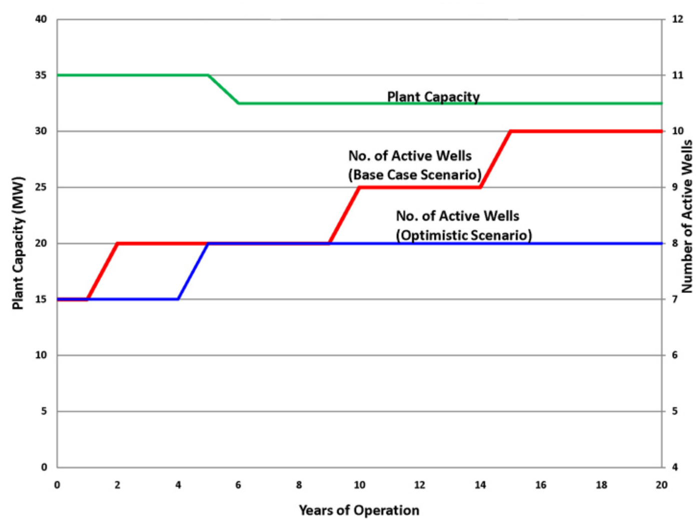

Figure 11. Approximate Forecast of Well Requirement.

A harmonic decline trend in well productivity is commonly observed at The Geysers (Sanyal, et al, 1989) and is represented by the equation:

$$W = W_i/(1 + D_i t), \quad (2)$$

Where W = production rate,
W_i = initial production rate, and
D_i = initial harmonic decline rate.

Using the above equation, the expected number of active wells required to maintain the plant capacity has been estimated as shown in Figure 11. The assumed decline rates are based on the assessment of all active production wells within a mile of the WGP Leasehold. Within this area most wells show either zero decline rate or actually increasing trends in well productivity because of augmented injection. Wells that are far from the injection areas show productivity declines but generally within 3% per year. Figure 12 shows an example of the productivity decline trend of an active well producing for 29 years and situated about a mile from the WGP Leasehold.

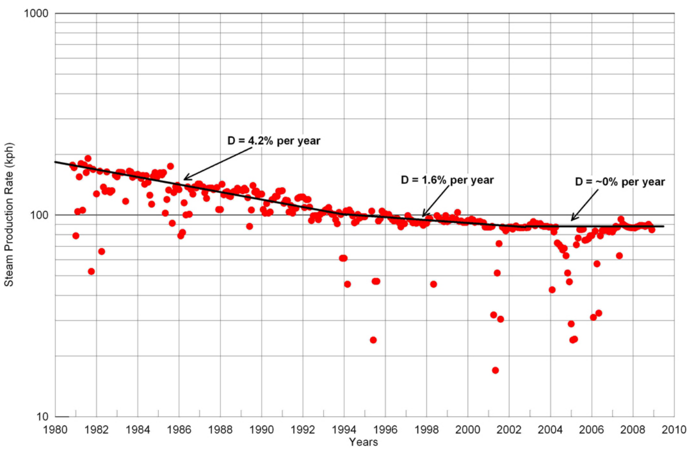

Figure 12. Production History of Well GDC-12.

The optimistic decline trend of 1% per year is seen in the portions of The Geysers field where injection has been substantially augmented by bringing in treated effluent from beyond the field. It is expected that Western GeoPower will be able to secure one or more sources of supply of such effluent, and as such, the optimistic scenario is a distinct possibility.

Given the estimated productivity decline trends, the corresponding decline trends in static wellhead pressure can be estimated as follows (Sanyal *et al*, 2000):

$$D = \left(\frac{2\,np_s}{p_s^2 - p_f^2} \right) \frac{dp_s}{dt} \tag{3}$$

Figure 13 shows the forecast of static wellhead pressure decline at the WGP-1/WGP-2 and WGP-3/WGP-4 well sites, as calculated from Equation (3) for the Base Case scenario.

This exercise indicates that under the Base Case scenario, the static wellhead pressure would decline to 213 to 221 psia after 20 years of production. This is reassuring, because all the wells will remain producible at a static pressure of this level. Publicly-available records show that many wells at The Geysers today produce at static wellhead pressures of even less than 200 psia. If the optimistic scenario comes true, the pressure decline would be even less.

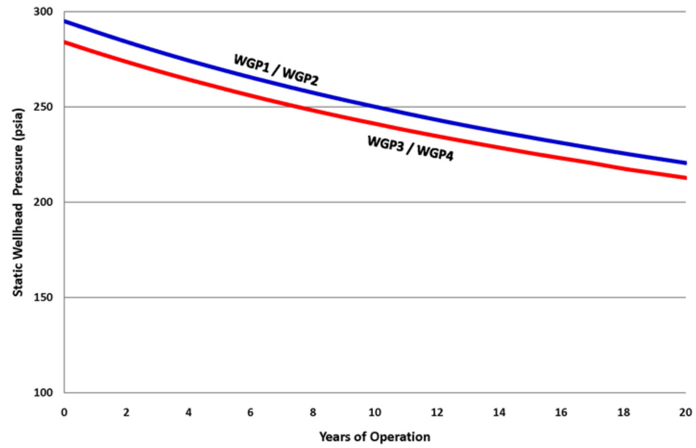

Figure 13. Expected Static Wellhead Pressure Decline Trend Under the Base Case Scenario.

Selecting Drilling Targets

This section describes the criteria used to select and prioritize targets for the production wells needed for the project. Figure 8 shows the high flow capacity areas within the reservoir as identified from the reservoir flow capacity values and productivities of the now-abandoned Unit 15 wells. These high flow capacity areas are considered the most favorable targets for production wells. The drilling targets were selected by the following process:

- Surface drilling locations (drilling pads) that could be utilized by the Unit 1 project were identified. All of the identified sites were used previously for the Unit 15 project, and were in good enough condition to be used again with minimal investments in repairs or improvements; they also could be permitted relatively easily and quickly, avoiding delays in the progress of the project.
- General zones to be targeted were selected based on the known distribution of reservoir productivity, as determined from analysis of the flow capacity (“kh”) and skin factor values from the Unit 15 project. A well that demonstrated a relatively high kh or production rate was assumed to lie in a “high” flow capacity area (Figure 7). It should be noted that essentially all areas of the selected target zones can be reached from the surface locations selected in the previous step.
- Specific drilling targets (i.e. the subsurface locations in the reservoir to which wells will be drilled to obtain production) were identified from analysis of the results of the Unit 15 wells. The rationale for this approach is that the production zones of the more productive Unit 15 wells constitute the most attractive drilling targets, because they offer a high probability of success compared with locations more distant from known productive wells. Both initial productivities and long-term productivities of the Unit 15 wells were taken into account, as well as consideration of whether each well’s productivity might have been affected by mechanical damage (as determined from its skin factor value) or other factors.

- Other criteria, including the need to keep a reasonable minimum spacing between production zones, and certain logistical factors, were applied to reduce the selection of targets to the 12 most attractive ones; of these 12 targets, four have been drilled.

The selected targets do not offer a guarantee of drilling success with each well, because productivity within the Geysers reservoir can vary over small distances. However, the selected targets offer the best statistical probability of success, and also provide an appropriate spacing and distribution of wells.

References

Energy Resources Conservation Board, 1975. “Theory and Practice of the Testing of Gas Wells,” Manual prepared by the Energy Resources Conservation Board, Calgary, Alberta, Canada, Third Edition, 1975.

Sanyal, S.K., A.J. Menzies, P.J. Brown, K.L. Enedy, and S. Enedy, 1989. “A Systematic Approach to Decline Curve Analysis for The Geysers Steam Field, California,” Trans. Geothermal Resources Council, Vol. 13, October, 1989.

Sanyal, S. K., S. J. Butler, P. J. Brown, K. Goyal, and T. Box, 2000. “An Investigation of Productivity and Pressure Decline Trends in Geothermal Steam Reservoirs,” Proc. World Geothermal Congress, Kyushu-Tohoku, Japan, May 28-June 10, 2000.

Sanyal, S.K., 2000. “Forty Years of Production History from The Geysers Geothermal Field, California,” Trans. Geothermal Resources Council, Vol. 24, 2000.

Sanyal, S.K., C.W. Klein, J.R. McNitt, R.C. Henneberger and K. MacLeod, 2008. “Assessment of Power Generation Capacity of the Western Geo-Power Leasehold at The Geysers Geothermal Field, California,” Trans. Geothermal Resources Council, Vol. 32, 2008.