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ASSESSMENT OF POWER GENERATION CAPACITY OF THE WESTERN GEOPOWER LEASEHOLD AT THE GEYSERS GEOTHERMAL FIELD, CALIFORNIA

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ABSTRACT

This paper presents a technical feasibility analysis of the Western Geopower Corporation's ("WGP") 25.5 MW Unit 1 power project at The Geysers steam field, California; the WGP leasehold covers 567 acres. A commercial power plant (P.G.& E. Unit 15) operated at this leasehold during 1979 to 1989; the plant was shut down and dismantled, and the wells were plugged and abandoned, mainly due to the unduly high rate of decline in well productivity then experienced throughout The Geysers field. A new geothermal power development at this site has several attractive attributes: (a) a long production history and a large amount of resource data are available; (b) a substantial infrastructure still exists intact at the site; and (c) the decline rates in reservoir pressure and well productivity throughout The Geysers field are far lower today than when the original plant operated. An assessment of the geological characteristics of the field indicates that at least 423 acres of the leasehold can potentially supply steam to a power plant. Based on the potentially productive acreage and the 10-year production history of the original wells, steam reserves within the leasehold are estimated to be sufficient to supply a 25.5 MW plant for a project life of at least 20 years.

INTRODUCTION

This paper presents a technical feasibility analysis of the Western Geopower Corporation's ("WGP") 25.5 MW Unit 1 power project at The Geysers geothermal field, California. 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. Commercial geothermal power has been generated continuously at The Geysers since 1960, the present generation level being about 900 megawatts. Figure 1 shows the presently known boundaries of the field (shown in green) and the historical boundaries of the various power plant units (shown in red). At this time two operators are generating power at The Geysers field: Calpine Corporation ("Calpine"), producing about 750 MW, and Northern California Power Agency ("NCPA"), producing about 150 MW. At its height in 1987, total net generation at The Geysers was nearly 1,800 MW. By 1995 the generation declined to the present level and stabilized due to several factors. First, some power plants were retired. Second, due to the unusually lucrative economics of power generation at The Geysers in the 1980s, the field had become over-developed, which led to a faster decline in well productivity than was sustainable economically and to a large extent technically also. This decline in well productivity could not be compensated for by drilling make-up wells because of the declining power price at the time (Sanyal, 2000).

The rapid rate of well productivity decline experienced during 1987-1995 was arrested by reduction in the overall generation level at The Geysers and augmented injection into the reservoir. Until 1997, the only fluid injected into the reservoir was the condensed steam from the power plant (about 20% to 25% of the produced steam mass) and minor amounts of water from local creeks and water wells, the total injection amounting to 30% to 35% of the produced steam mass. 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 produced steam mass is replaced by injection. This augmented injection over the past nine years 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 about 1% to 2% today. Therefore, power generation at The Geysers has become attractive again.

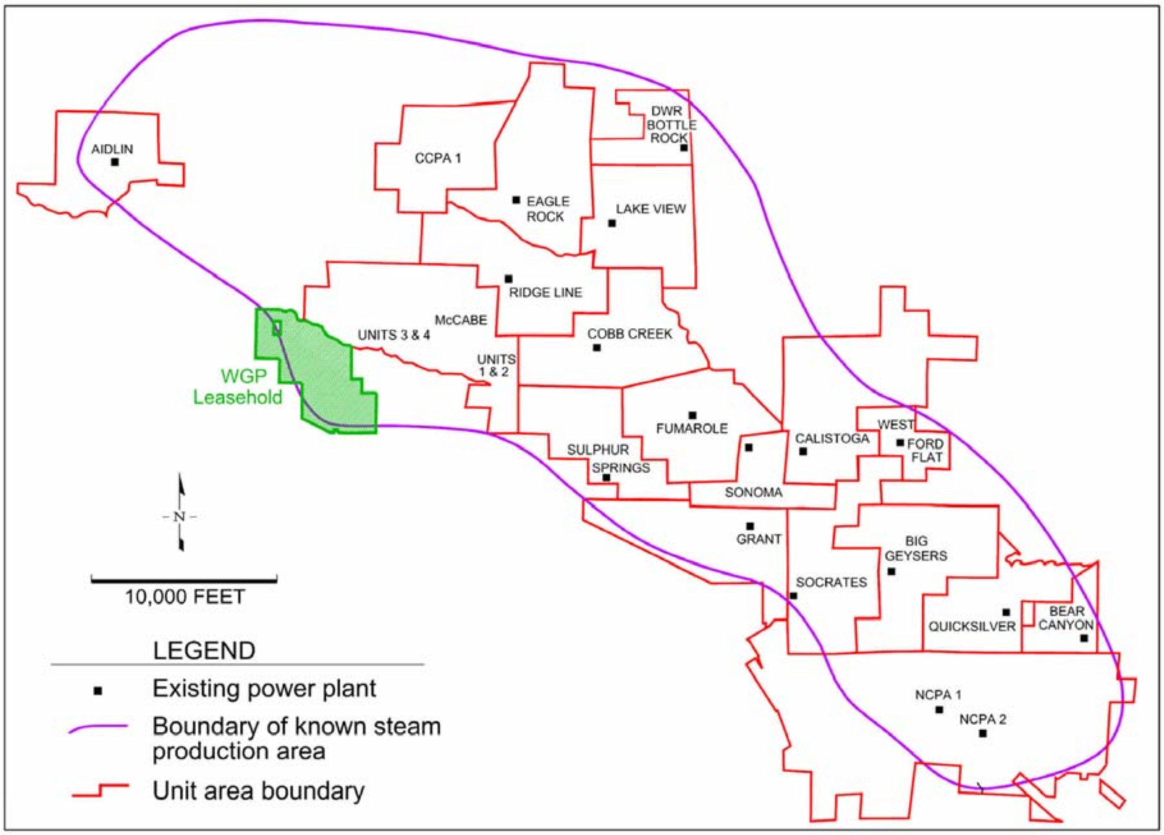

Figure.1: Historically dedicated areas within The Geysers Geothermal Field

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 2). A commercial power plant of 62 megawatt (gross) capacity, known as P.G. & E. Unit 15, operated at this leasehold during 1979 to 1989. It is now recognized that the Unit 15 plant was oversized for the available resource, as was the case for many other power plants installed at The Geysers prior to 1989. For this reason, the wells supplying the Unit 15 power plant experienced a rapid decline in productivity. 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 this 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 will reduce the capital cost of development of a new power generation project. Reservoir pressure under the leasehold should have substantially recovered by now because of three factors: (a) decline in overall generation level at The Geysers, (b) absence of production from this leasehold for nearly 18 years, and (c) a large increase in the fraction of produced mass that is now injected. Therefore, when new wells are drilled on this leasehold, the initial well productivity should be higher and well productivity decline as well as pressure decline should be lower compared to what they were at the time the plant was shut down.

GEOLOGIC CHARACTERISTICS OF THE FIELD

The relevant geologic characteristics of the leasehold were assessed primarily from the evaluation of the drilling and production histories of wells drilled on the lease prior to the abandonment of the Unit 15 power plant. Figure 3 shows the location of the leasehold in relation to the known production area of the field. On this map, the location and extent of the Geysers Field are defined by contours drawn on the

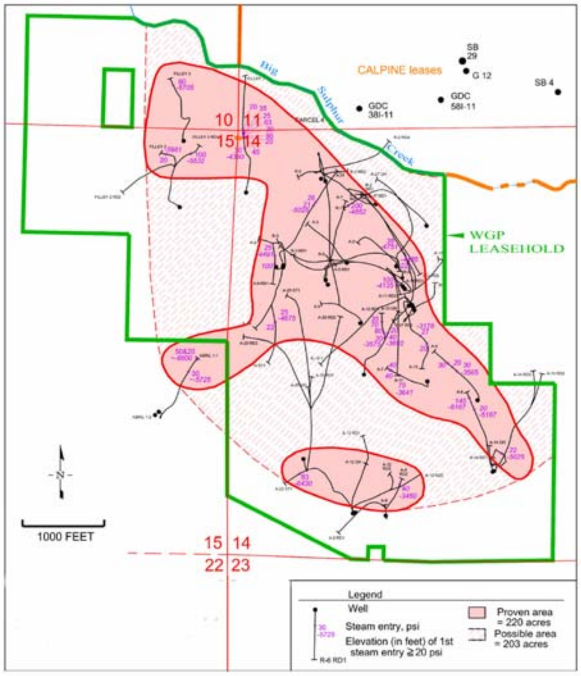

Figure. 2: Map of well traces and location of steam entries ≥ 20 psi

highest elevation of steam entries recorded in production wells. This "top of steam" map illustrates the regionally simple geometry of the Geysers reservoir:

1. The reservoir is elongated NW-SE, paralleling the NW-trending ridges and valleys of the Mayacamas mountain range, indicating that the geometry of the reservoir is controlled by the same geologic structures that control the morphology of the region.

2. The highest elevation of the reservoir is a NW-trending linear zone located along the SW side of the field. From this ridge, the top dips gently to the NE but drops much more abruptly to the SW. Because subsurface stratigraphy at The Geysers is poorly understood, the underlying structure causing this asymmetry cannot be defined with certainty; the simplest explanation, however, is that the Geysers reservoir is confined within a NE-tilted fault block bounded by a NW-trending fault on the SW and a NW-trending dip slope on the NE. The leasehold straddles the steep, SW edge of the field. This interpretation is consistent with bedding attitudes measured on the surface and the geometry of marker beds identified in the subsurface.

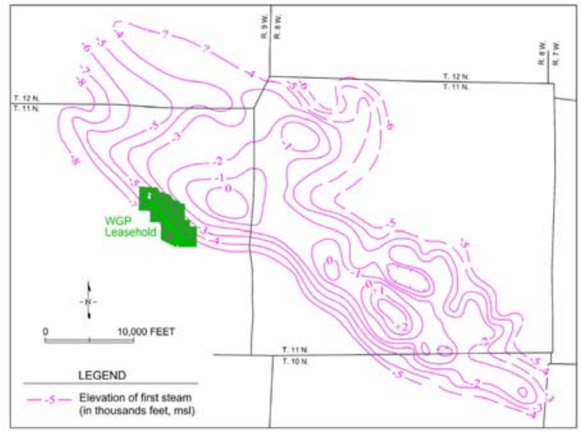

Figure.3: Contour map of elevation (feet msl) of first steam entries, The Geysers Steam Field, California (after Dykstra et al, 1980)

A detailed map of the top of steam within the leasehold was constructed from data obtained from 28 wells, plus re-drills, within the leasehold and several wells drilled adjacent to the leasehold on the NW and SE. This map shows that, within the lease, the top of steam is deeper than the top encountered in the central parts of the Geysers field. The elevation of the steam top is between -4,000 and -5,000 feet msl in the NW quarter of the lease, and drops to an elevation as deep as -6,000 feet along the south side. A small area in the central part of the Unit 15 leasehold is in the -3,000 to -4,000-foot elevation range. In the central part of the Geysers field the top of steam is generally above -3,000 feet msl.

In addition to this difference in depth to the top of steam, reservoir lithology in the leasehold area is different from the lithology of the central part of the field. This is probably due to the offset of stratigraphic sequences by the fault separating the two areas. Steam production in the central part of Geysers field is from random fractures developed in thick layers of massive, hard sandstone ("graywacke"). These layers are interbedded with relatively thin layers of soft shale ("argillite"), which do not sustain fractures. The hard sandstone layers underlying the leasehold are generally thinner than the layers in the central part of the Geysers field and are interbedded with a relatively high percentage of un-fractured, soft shale. Because this sequence provides relatively fewer fractures per linear foot drilled, the Unit 15 wells tended to be somewhat less productive. The average, initial productivity of wells drilled in the main Geysers field was about 5 to 6 MW, whereas in the Unit 15 leasehold it was about 3 to 4 MW. However, given the lower pressure level in the central part of The Geysers Field today compared to the WGP leasehold, this historical difference in well productivity is no longer as significant. But, the presence of shale in the leasehold adds hole instability, which can cause stuck pipe and twist-offs, resulting in a higher proportion of fishing time than in the central part of the field.

Figure 2 shows the subsurface traces of all the wells drilled on the leasehold, the locations along the drill path where steam entries with pressure "kicks" in excess of 20 psi were encountered, and an estimated elevation of the first steam entry. The elevation estimates are generally a few hundred feet higher than actual elevations, because a correction could not be made for all wells for the difference between measured and true vertical depths in all of the deviated wells. The area of the leasehold under which steam entries have been found is approximately 220 acres; we consider this area to be "proven" area. Another 203 acres of the leasehold around the productive area have not been explored and may contain additional productive ground; this acreage we consider to be "possible" area. Thus, at least 423 acres within the Unit 15 leasehold can potentially supply steam to a power plant.

STEAM RESERVES

Estimation of steam reserves at The Geysers, and indeed in all dry steam fields, is complicated by the fact that the distribution of water saturation within the reservoir in various parts of the field is not known, and no direct measurement of this saturation distribution is possible. Yet, the extent of water saturation is a critical determinant of the steam reserves, because water in the pores and fractures boils off to supply the steam produced by wells. Even with this constraint there are two approximate approaches to determining the steam reserves at The Geysers; these are discussed below.

EMPIRICAL APPROACH

Such an approach invokes certain "rules of thumb", based on local experience at The Geysers Field, as to how much steam reserve has historically been available per acre of productive ground or how many acres of productive ground had historically been dedicated per well to ensure steam supply for a project life of 20 to 30 years. One such rule of thumb is to assume that at least 40 acres per well are required to sustain a well's productivity for 20 to 30 years. In the WGP leasehold about 220 acres have been proven productive to date; at a well spacing of 40 acres per well, 5 wells can be located within this area. As discussed later, an average well in this leasehold is expected to have a capacity of 3.6 MW (net); therefore, the proven area has reserves sufficient to supply a plant of at least 18 MW (net) capacity. On the other hand, we have estimated in a total proven-plus-possible area within the WGP leasehold of 403 acres, which can accommodate about 10 wells. Therefore, up to 36 MW (net) would be available if the entire "possible" area is proved productive by drilling. Therefore, an 18 to 36 MW (net) generation can be supported within the WGP leasehold.

THE "P/Z" METHOD

This approach, commonly used in natural gas engineering, has been routinely applied at The Geysers Field. It consists of estimating the ratio of the static reservoir pressure, p, to the "real gas deviation factor", z, as a function of cumulative steam production from the reservoir over time (Sanyal et al, 1989). The variable z is defined by Real Gas Law:

$$pv = znRT, \tag{1}$$

where v is specific volume, n is number of moles, R is the Universal Gas Constant and T is absolute temperature. It can be shown that for a confined gas reservoir a plot of the ratio p/z versus cumulative gas production should be linear. By extrapolating this linear trend to the p/z value corresponding to the "abandonment pressure" condition, one can estimate the steam reserves available before the abandonment condition is reached. This approach is conservative when there is water saturation in the reservoir, that is, steam reserves are likely to be higher than the estimate made by this method. The p/z plot is linear during the first few years of production but then tends to flatten out, implying a higher reserve than would be estimated by extrapolating the linear trend.

A static reservoir pressure of 100 psia was considered the abandonment pressure, for this project. Figure 4 is a plot of p/z versus cumulative net production that is production minus injection data; if a linear trend is defined through the data points then Figure 4 indicates a steam reserve of 90 billion pounds. Subtracting the net mass of steam produced during the 10 years of operation of the Unit 15 plant, we estimate the available steam reserve today to be at least 40 billion pounds for the abandonment p/z level; WGP's conceptual design of the power plant call for 19,000 lbs/hour of steam per net MW generation; assuming at least 35% of the produced mass will be injected in the form of steam condensate and supplemental water and a 95% plant capacity factor, this steam reserve can support a generation level of 25.5 MW (net) for at least 15 years. This estimate is conservative because we believe there is water saturation in the reservoir underlying the area. There are two reasons for this belief: (a) during exploitation of the Unit 15 area no pervasive superheating of the steam had been experienced, and (b) the absence of production from this part of the field over the last 18 years should have increased the water saturation in the reservoir locally, due to condensation of steam or some other natural recharge phenomena, as well as infiltration of injected fluid form outside the leasehold (Klein and Chase, 1995).

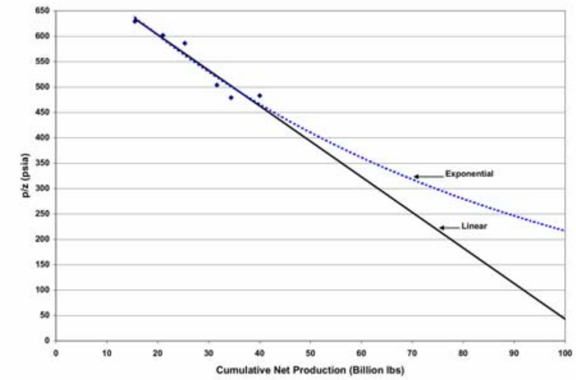

Figure. 4: Cumulative Net Production (Billion lbs)

Since the data trend on the p/z plot is expected to be flatter than the linear trend defined from the first few years of production (as shown in Figure 4, where we have also shown an exponential curve fit). Using this latter trend extrapolated to a p/z value of 105 psia and subtracting the net steam mass produced up to 1989, we estimate the remaining reserves at 106 billion pounds. At 19,000 pounds per hour per MW (net), a 35% injection rate, and a 95% plant capacity factor, this higher estimate of steam reserves is equivalent to a 25.5 MW (net) capacity for 40 years. Therefore a 25.5 MW (net) capacity for a 20-year project life is a reasonable expectation.

WELL PRODUCTIVITY

HISTORICAL WELL PRODUCTIVITY CHARACTERISTICS AT THE GEYSERS

The historical trends in well productivity at The Geysers can be illustrated with reference to the history of a typical well (GDC-12), which is located about a mile east of the WGP leasehold and has been in continuous production for the last 26 years. Figure 5 shows the steam production rate from this well (in kilo-pounds per hour or "kph") versus time since 1980, the steam production rate being shown on a logarithmic scale. The data points in Figure 5 define two separate linear trends, one from 1980 to about 1995 and another from 1995 onward. A linear trend on such a plot defines an exponential decline trend, given by:

$$W = W_i e^{-Dt}, \qquad (2)$$

where W = steam production rate at time t,
W_i = initial steam production rate, and
D = decline rate.

The slope of the linear trend is equal to the decline rate, D.

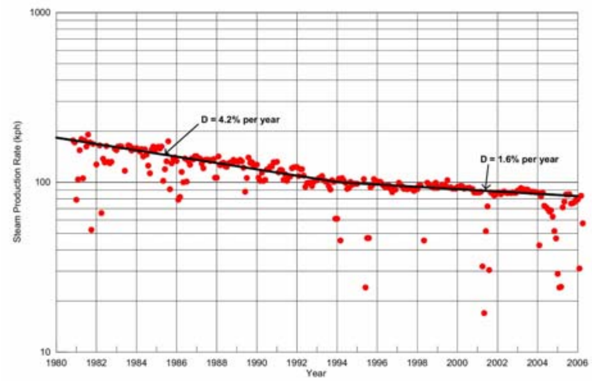

Figure. 5 Production History of Well GDC-12

Figure 5 indicates that up to 1995, the steam production rate from this well declined at a constant annual rate of 4.2%, and after 1995, the decline rate was 1.6% per year. This sudden and sharp lessening in well productivity decline was caused, as discussed earlier, due to the curtailment in the generation level and augmentation of injection. Figure 5 indicated that the most recent decline rate could be even lower. Therefore, we have assumed a minimum possible productivity decline rate of 1% per year, and a maximum possible rate of 2% per year, with a rate of 1.6% being most likely.

<u>Historical Well Productivity Characteristics within WGP Leasehold</u>

Figure 6 shows the total production rate from the Unit 15 wells over the years of Unit 15 operation. Figure 6 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 from the reservoir generally reflects the decline in static reservoir pressure. Figure 7 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.

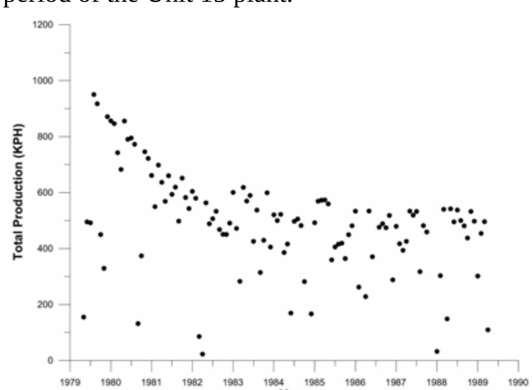

Figure. 6: Total Flow Rate History of Unit 15 Wells

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):

$$W = C\left(p_s^2 - p_f^2\right)^n, \qquad (3)$$

where W is steam production rate from a well, C is a parameter of the well, ps is static wellhead pressure, pf 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.

Using equation (3) we have estimated how the steam flow rate from a well, producing at a flowing wellhead pressure of 150 psia (typical of the wells in the early years of Unit 15's production), should have declined as static wellhead pressure declined from its initial level of 450 psia in 1979. Figure 6 indicates that the total production from the Unit 15 wells dropped by about 50% by 1983. Figure 7 shows that in 1983 the static wellhead pressure of a Unit 15 well would have been about 280 psia. From (3) it can be estimated that, at a static wellhead pressure of 280 psia and within the n value range of 1.0 to 0.5, the productivity of a well should have fallen by nearly 50% by 1983. In reality, the average well productivity remained relatively unchanged during Unit 15's operation; this happened because while the static wellhead pressure underwent decline, the flowing wellhead pressures of wells were gradually reduced from about 180 psia initially to 100 psia by 1989. 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 apparently kept the total flow rate from the Unit 15 leasehold relatively constant from 1984 until the plant was shut down in 1989.

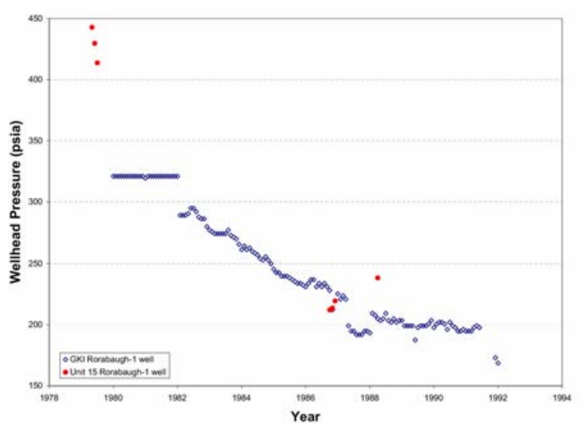

Figure. 7: State Wellhead Pressure History in the Unit 15 Area

EXPECTED WELL PRODUCTIVITY CHARACTERISTICS

Once the values of n and C for a well have been estimated, estimate its steam production rate for any flowing wellhead pressure if the static wellhead pressure is known. Since 1989, when the plant was shut down, there has been no monitoring of the wellhead pressures in the WGP area; therefore, the current static wellhead pressures in the area are unknown. As shown in Figure 7, when the plant was shut down in 1989, the static wellhead pressure was about 200 psia. Following plant shut-down, the static wellhead pressure did not recover promptly because production from the rest of The Geysers field continued, and at a much higher rate than prevails today. It is not known how much the static wellhead pressure in the WGP area has recovered by now in response to the curtailed production and augmented injection at The Geysers since 1989.

We have estimated approximately what the current level of static wellhead pressure in the WGP area would be (had the wells not been abandoned) by an indirect approach as follows. Continuous histories of static pressures at the mean sea level from 9 wells within a few miles of the WGP leasehold are available publicly; Figure 8 shows the locations of these wells. From the static pressures of the wells at mean sea level, we have calculated the corresponding static wellhead pressures. In Figure 8 we have contoured these estimated static wellhead pressures; this figure shows a "pressure sink" that extends southeastward, due obviously to production from the Calpine and NCPA areas, and shows that the wells in the WGP area would have had a static pressure level in 2006 in the 240 to 260 psia range. Therefore, we have assumed a mid-range value of 250 psia for the 2006 static wellhead pressure of a representative well within the WGP leasehold. However, there is anecdotal information suggesting that the static wellhead pressures within the WGP leasehold might be higher (Williams, 2006).

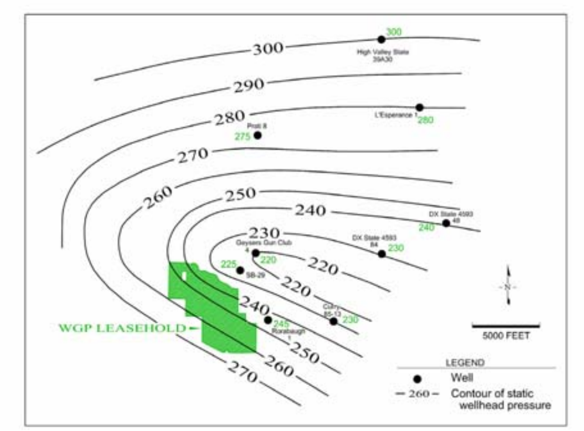

Figure. 8: Cumulative Net Production (Billion lbs)

The Unit 15 wells were flowing typically at a wellhead pressure of 100 psia at the time the plant was shut down. For the conceptual design of the plant for the subject project we have considered a lower flowing wellhead pressure of 80 psia to maximize possible steam production. However, any further lowering of flowing wellhead pressure is not realistic, as any consequent increase in steam production would be largely negated by a corresponding reduction in power plant conversion efficiency.

Using the estimated n and C values of wells, a flowing wellhead pressure of 80 psia and a static wellhead pressure of 250 psia, we have estimated the production rate that would have been available from each Unit 15 well had it not been abandoned. From this exercise we estimate an average present well productivity value between 69,000 and 76,000 lbs per hour. We have also compared this estimate with the present productivities of the Calpine's active wells, from publicly available records, nearest to the WGP area. Figure 8 indicates the static wellhead pressure at these wells to be on the order of 220 psia. Assuming a static wellhead pressure of 220 psia, we have estimated the current production rates available from these wells for a flowing wellhead pressure of 80 psia. This exercise indicates that the average current productivity of these wells is in the range of 52,000 to 56,000 lbs per hour depending on the assumed n value. Furthermore, we estimate that if the static wellhead pressure at these wells were 250 psia, which is the estimated current static wellhead pressure in the WGP area, then the average productivity of these Calpine wells would be 60,000 to 75,000 lbs per hour at a flowing wellhead pressure of 80 psia.

From the discussion above we can conclude that an average production rate on the order of 70,000 lbs per hour is a reasonable expectation from the wells to be drilled on the WGP leasehold. Given the requirement of 19,000 lbs per hour of steam per MW (net) generation at the power plant, this flow rate represents an average well capacity of 3.6 MW per well. If the static wellhead pressure within the WGP leasehold proves to be higher or lower than 250 psia, the average well capacity would be correspondingly higher or lower.

CHEMICAL CHARACTERISTICS OF THE STEAM

GASES IN STEAM

The monthly average non-condensable gas ("NCG") concentration in steam at the inlet of the Unit 15 plant was about 2,000 ppm-wt in mid-1979, shortly after the start of production (Figure 9). Thereafter, the NCG concentration increased at a uniform rate until early 1983, reaching about 7,000 ppm-wt and then remaining nearly stable through mid-1985. By comparison, it is reported that the Unit 15 power plant was designed to handle NCG of only 4,000 ppm-wt. Plant inlet data for the period from late 1985 to 1989 were not available for this study, but a set of samples collected in 1986 had a flow-weighted NCG average of 9,500 ppm-wt. The difference between 7,000 and 9,500 ppm-wt is large enough to imply some change in operating conditions, such as shifting wellhead pressure, a change of production wells, changes of relative flow rates and/or increasing gases at an otherwise steady-state. There was a large range of gas/steam values from well to well (2,900 to 14,500 ppm-wt in 1986), and it would not take a very large shift of production to shift the plant inlet average value.

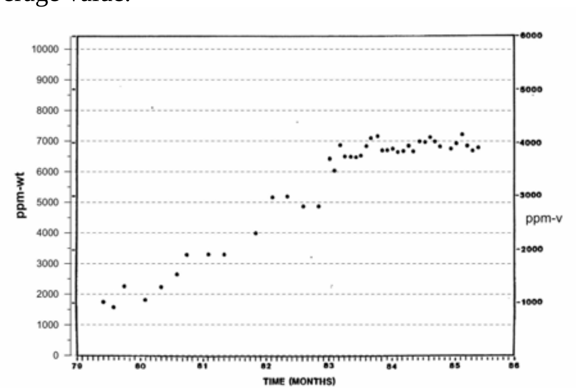

Figure. 9: Unit 15 steam field monthly average gases in steam vs time, 1979-85 (After GEO Operator Corporation, 1985)

Gases in steam at most Unit 15 wells were sensitive to wellhead pressure, at higher levels especially, tending to decline as pressure was decreased. As of 1986 the production wells were flowing typically at wellhead pressures in the range of 140 to 155 psig. The direct relationship between ppm-wt and pressure has been attributed to the fact that wellhead steam is a combination of pre-existing reservoir steam (with higher gases) and reservoir steam that is freshly produced by the boiling of the reservoir liquid (with lower gases) that is contained in the pore volume of the reservoir. When production pressures are lowered there is more boiling, which increases flow rate and also dilutes the gases in steam. Gas concentration was the highest in the center and north of the production area, and decreased moving outwards to the SE, S and SW and W.

The monthly average content of H_2S (Unit 15 plant inlet sample) was about 130 ppm-wt in late 1979 and increased at a steady rate along with total gases, to about 350 ppm-wt in mid-to-late 1982, shortly before the total gases became stable. Data for 1983 through mid-1985 were not available, but it is reasonable to assume a proportional increase which matches the increase of total gases. On this basis, H_2S in steam in mid-1985 would have been about 450 to perhaps 500 ppm-wt. The set of samples collected in 1986 had a flow-weighted average H_2S content of 540 ppm-wt.

INJECTION EFFECTS ON GAS CONTENT

When steam condensate or condensate with added meteoric water is injected into the reservoir, the steam that is created has practically no dissolved gases and a stable isotope composition that is different from original reservoir steam. The isotope difference can be quite large when condensate alone is injected, because condensate isotopes undergo a large shift when there is evaporation to the atmosphere before injection (as is usually the case). Figure 10 illustrates the range of original isotopic composition in The Geysers reservoir steam and in the injected condensate. In recent years a large amount of meteoric water from streams, catch basins, shallow wells and treated municipal effluent has been added, greatly complicating the picture. A small amount of isotope and associated gas data from 1982 to 1984 were found for this study, and included in Figure 10. Each of the four wells sampled shows a progressive decrease of gases in steam that is associated with an isotope shift towards mixing with injected steam condensate. The data suggest that by 1984 three of the wells (A-4, A-11, A-13) were producing 35 to 50% injectate, and well R-2 was producing at least 70 to 80%.

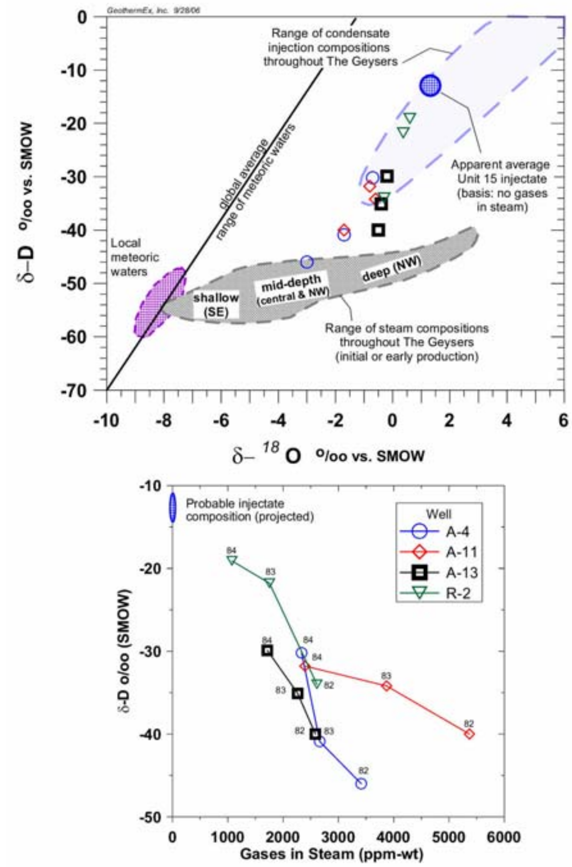

Figure.10: Stable isotopes and gases in steam among The Geysers Unit 15 samples collected during 1982-84

Available data do not allow reconciling the fact that gases were decreasing at certain wells during 1982 to 1984 due to injection, yet total gases at the plant inlet were still increasing during the same period. It is possible that the plant inlet gases ceased to increase in early 1983 as a result of injection, but this is a highly tentative conclusion without support from actual data on injection well locations and flow rates, and more complete gas chemistry and isotope data. Another cause of the gases leveling off would be the depletion of steam from gas-poor, condensate-enriched shallow production zones, which was indicated by the appearance of Cl in the Unit 15 steam.

HCL CORROSIVITY

Traces of Cl are present in all Geysers steam, but at superheated, high-gas wells in the northwestern parts of the field, and in the WGP area, this Cl is more abundant. Concentrations of Cl in dry steam that exceed about 10 ppm are highly corrosive, because the Cl travels as hydrochloric acid (HCl), which is highly soluble in steam condensate. Traces of condensate that form at points of heat loss on well casings, wellheads and surface pipelines become extremely acidic and are corrosive. This condition can be particularly troublesome in a well with a very small level of superheat downhole. Fortunately, HCl corrosion can be mitigated by injecting a small amount of sodium hydroxide solution (NaOH) downhole. This has been done routinely at the Aidlin project ever since that unit went on-line nearly 20 years ago. As back-up protection, surface lines are designed and insulated to minimize heat loss. Similar corrosion abatement had been practiced at the CCPA leasehold.

The HCl is believed to come from the deepest and hottest sources of production in the field, either a brine layer at a temperature higher than 300°C, or at locations where superheated steam reacts with crystalline NaCl. Neither source is present in the Southern part of the Geysers, where HCl does not appear. In the Unit 15 steam, HCl was not present in early production because shallower reservoir zones initially contained liquid water, which stripped the HCl from the steam coming from below. Later, as a result of reservoir dry-out in shallower zones, HCl apparently started to enter the wells.

Prognosis

During the early years of Unit 15 production, if a well was shut-in for more than about a month, there would be some build-up of reservoir condensate nearby. As a result, when the well was re-opened, initial flow rates were high, and NCG levels low. In later years, reservoir condensate was more generally depleted, and this did not happen. Whether this dry-out pattern will be observed at new wells to be drilled on the WGP leasehold depends upon the effects of production and injection within the adjacent Calpine leases since the Unit 15 plant was shut in. If production has caused dry-out within the WGP leasehold, then initial gases may already be at the levels observed in 1985-86, and possibly higher on average. If injection in adjacent leases has diluted reservoir gases in the WGP area, then initial levels may be lower. We believe the latter situation is more likely.

An additional factor relating to future gas levels is that the planned production wellhead pressure is 80 psia. If the pressure-related trends seen from the data still apply, then the initial gas levels at the individual new wells could be in the range of about 1,500 to 7,000 ppm-wt, averaging about 4,000 ppm-wt. The pressure-related trends may, however, be more strongly related to boiling of shallow reservoir liquid than deep reservoir liquid. If the shallow-zone liquid becomes depleted at all wells, particularly at very low wellhead pressures, then the tendency for gases to decrease with decreasing pressure may disappear. Therefore, the 15,000 ppm-wt gases attained by some wells in 1985 is a probable upper limit for all wells and a maximum possible value for plant inlet average steam, because this probably corresponded to near-complete dry-out of shallow production. Given the augmented injection practiced today, this dry-out is now unlikely. Available data suggest that at dry-out the concentration of H_2S would be about 750 ppm-wt. It seems unlikely that all wells will reach this maximum gas level, and more probable that the average gases at plant inlet will not exceed about 10,000 ppm-wt (which is suggested at 125 psig, the lower limit of data). Corresponding H_2S would be perhaps 600 ppm-wt or lower. It may also be expected that, over the long-term, deep boiling in the high-gas wells will tend to deplete the gases in deep reservoir liquid, leading to a decline of gas levels over time after an initial maximum is reached, unless there is a continuing source for additional gases such as the very top of reservoir and reservoir cap as suggested by Powell (2004).

These estimates are based on historical gas levels that are presumed to include some dilution by injection, but injection records have not been available. If there will be higher levels of injection in the future, or if gases have already been diluted by injection in the adjacent Calpine area, then future gas levels will be yet lower. As a rule of thumb, the average gas concentration would decline by about the same percentage as the percentage of produced mass of steam that is injected. As discussed in the next section, we have assumed that about 35% of the produced mass will be injected.

Although historical experience with the Unit 15 plant has been that wells with gases at less than 10,500 ppm-wt may not need corrosion abatement, it should not be assumed that future production at lower wellhead pressures (and possibly lower gas levels) will eliminate production of HCl and the need for corrosion abatement. This is because the presence of HCl is also a function of superheat, which may increase at lower pressures. The historical amount of superheat at Unit 15 wellheads has been minimal, but HCl production requires shallow reservoir dry-out, so a very small amount of superheat was probably present at the high HCl wells. Carefully controlled injection can be used to suppress gas concentrations and production of HCl, without unacceptable detriment to well production.

OTHER FIELD DEVELOPMENT ISSUES

Initial Well Requirement

We have assumed an initial static wellhead pressure of 250 psia and a flowing wellhead pressure of 80 psia. Furthermore, we have made the reasonable assumption that the existing well Rorabaugh A-17 will be reworked and used as the injection well. Given the highly underpressured nature of The

Geysers field, one injection well will be adequate for the project, at least initially. The necessary production wells are assumed to be new wells. The need for 10% reserve production, even if that requires an extra well (as a standby well), was assumed.
In the Base Case scenario we have assumed an average capacity of 3.6 MW (net) per well, while for the Conservative scenario we have assumed a capacity of 3.0 MW (net) per well. The assumed capacities represent stabilized capacity; steam wells at The Geysers typically undergo some decline in capacity over the first few weeks of production before they stabilize. With the above assumptions, we estimate the need for 8 production wells for the Base Case scenario and 10 production wells under the Conservative scenario.

Based on the depths of first steam entry, production wells are expected to be in the range of 6,000 to 8,000 feet deep vertically. The production wells for the Base Case and Conservative scenarios are expected to be drilled directionally. For the Optimistic scenario we have assumed that the wells will be "forked" wells, that is, each well will be drilled with two producing legs (Henneberger *et al*, 1995). A forked well should have a significantly higher productivity than a conventional well (Sanyal *et al*, 2007).

Pressure and Well Productivity Decline

Production wells at The Geysers undergo a "harmonic decline", that is, the decline rate itself declines with time (Sanyal *et al*, 1989). A harmonic decline trend is defined as:

$$W=W_i/(1+D_i t), \tag{4}$$

where W_i is initial production rate, W is production rate at time t, and D_i is the initial productivity decline rate. For small values of productivity decline rate as expected for this leasehold, equations (2) and (4) give essentially the same trend. We have used equation (4) in estimating the long-term well productivity decline to be expected for the WGP Unit 1 project after initial stabilization of well productivity. For the Base Case scenario we have assumed an initial annual productivity decline rate of 1.6%, for the Optimistic scenario 1%, and for the Conservative scenario 2% per year. Given the above decline rates we estimate the need for one make-up well every 9 years under the Base Case scenario, every 16 years under the optimistic scenario, and every 5 years under the Conservative scenario.

In the Optimistic scenario the initial reserve production capacity will obviate the need for make-up well drilling for 10 years; thereafter, one well will be required every 16 years to sustain generation over the remaining project life. Under the Base Case scenario, the initial reserve production capacity will delay the need for make-up well drilling by 8 years; thereafter, a make-up well be required every 9 years. For the Conservative scenario the initial reserve production capacity will be used up in 9 years; thereafter, a make-up well will be required every 5 years. In other words, under the Base Case scenario, the first make-up will need to be drilled after 8 years and a second one after 17 years to maintain generation for 26 years. Similarly under the optimistic scenario we estimate the need for the first make-up well after 10 years and a second one after 16 years, to maintain generation for 26 years. For the Conservative scenario, we estimate the need for the first make-up well in year 9, a second one in year 14, and a third one in year 19 to maintain generation for 24 years.

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

$$D = \left(\frac{2\,np_s}{p_s^2 - p_f^2} \right) \frac{dp_s}{dt} \tag{5}$$

This exercise indicates that even under the Conservative scenario, the static wellhead pressure remains above 175 psia after 20 years of production. This is reassuring, because all the wells will remain producible at a static pressure of 175 psia. Publicly-available records show that many wells at The Geysers today produce at static wellhead pressures of even less than 175 psia.

CONCLUSIONS

Expected characteristics of the wells to be drilled were defined based on an analysis of the database on the wells that once supplied the Unit 15 power plant as well as publicly available records on the existing wells within The Geysers field. The new wells, estimated to be 6,000 to 8,000 feet deep vertically, are anticipated to show static wellhead pressure and steam production rate per well of about 250 psia and 70,000 pounds/hour, respectively; this implies 3.6 MW capacity per well. At least 8 new production wells will be required to supply the plant; the annual decline rate in well productivity is anticipated to be 1% to 2%. The sole existing well in this leasehold, when reworked as an injector, should provide the required injection capacity for the steam condensate. Even under the most conservative scenario, the static wellhead pressure after 20 years of production is estimated to remain above 175 psia, which is higher than reported from many producing wells at The Geysers field today. The non-condensable gas content and hydrogen-sulfide content in steam are expected to average about 4,000 ppm-wt and 600 ppm-wt, respectively; these values are within the range encountered in producing wells in The Geysers field. Production of superheated steam, which can induce corrosion, is unlikely to be a significant problem.

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