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RESERVOIR RESPONSE TO PRODUCTION: CASTLE ROCK SPRINGS AREA, EAST GEYSERS, CALIFORNIA, U.S.A.

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ABSTRACT

Steam deliverability of the original 20 wells, supplying steam to PG&E Unit 13 power plant, has undergone five different decline trends since unit's start up in May 1980. High decline rates after 1984 were influenced by the regional effects associated with the installation of new capacity in the adjoining areas totalling 383 NMW in 1983-84 and 347 NMW in 1985-86. Unit 13's production declined Harmonically for the first 6.6 years, near exponentially for the next year and hyperbolically to harmonically thereafter. Near exponential decline trend resulted from the combined effect of local and regional pressure drawdowns and an accelerated makeup well drilling program. Analysis of the decline rate versus generating capacity suggests that a sustainable 2 MW per month decline is achievable if the capacity is held at about 160 NMW in the Unit 13-16 wellfield and 830 NMW in The East Geysers.

INTRODUCTION

Flow rate decline, observed at The Geysers, is caused by the pressure drop in the reservoir in response to continuous mass withdrawal from the steam field. These decline rates depend on several factors such as steam withdrawal rate, well spacing, water saturation, reservoir thickness, matrix and fracture permeability, fracture spacing, wellbore scaling and well location with respect to field boundaries and producing areas (Budd, 1972; Dee and Brigham, 1985; Bodvarsson and Witherspoon, 1985). Decline curve analyses are widely used at The Geysers to forecast deliverability behavior, makeup well requirements, workover candidate wells, injection effects and recoverable reserves. The theoretical basis of this analysis is presented in Zais and Bodvarsson (1980).

Steam production decline at The Geysers has been studied by Budd (1972), Stockton et al.,(1984), Sanyal (1985), Ripperda and Bodvarsson (1987), and Enedy (1987). Budd developed decline curves for various well spacings by simulating flow conditions within the steam reservoir. These curves, reproduced in Figure 6, indicate that an increase in well density increases the decline rate due to enhanced interference between the wells. Stockton et al.,(1984) constructed an average production decline curve from 18 wells representing several wellfields with 7 or more years of production history. That curve exhibits a harmonic trend with an annual decline rate of 12.5% as shown in Figure 6.

Using a ratio of present MW to initial MW, Sanyal (1985) developed decline curves for PG&E Units 1-6, 7-8, 9-10, 11 and 12. He compared these average unit decline rates with those presented by Budd (1972) and Stockton et al.,(1984). Sanyal observed that Units 1-6 did not exhibit any decline for the first four years. Afterwards these units display a decline rate which lies between Budd's 20 and 45 acre spacing. The decline behavior of Units 7-8 remained between Budd's 20 acre spacing and Stockton et al.'s 12.5% harmonic decline. The behavior of Units 9-10 was similar to Units 1-6. Declining trends of Unit 11 and Unit 12 were similar to Units 7-8 and Units 1-6 respectively. Average field wide (PG&E Units 1-12) decline rates remained between Budd's 20 and 45 acre spacing curves. Sanyal observed that Budd's harmonic decline with 20 acre spacing is most reasonable at The Geysers.

Ripperda and Bodvarsson (1987) developed decline curves on the basis of actual data from 30 Geysers wells at 40 acre spacing, 9 wells at 10 acre spacing and 33 wells at 5 acre spacing. They found that the flow rate decline is usually near harmonic and a minimum production history of 5 years is needed to determine the type of decline. These authors also concluded that the dependence of well spacing on the decline rate is not as high as projected by Budd (1972). For 5 acre well spacing case, Ripperda and Bodvarsson obtained a harmonic annual decline rate of only 12.5% compared to about 20% predicted by Budd (1972). However, for 40 acre spacing their decline of 8.33% was about twice the 4% decline rate of Budd (1972) for 45 acre well spacing. Enedy (1987) studied the decline rate of 12 wells from NCPA 1 wellfield and found that the wells decline hyperbolically or harmonically. He also observed that a field should produce for about 4 years to determine whether it is declining harmonically, hyperbolically or exponentially.

In this paper, the decline behavior of the original 20 wells which have been supplying steam to the Unit 13 power plant since its start up in May 1980 is studied. Steam production decline in these wells occurred under actual field conditions where factors such as steam withdrawal rate, well spacing, injection rate and wellbore scaling have been somewhat variable over the 9 year production history of the field. Unit 13's decline trends are identified on the basis of local and regional decline concepts. These decline trends are also compared with the other decline trends reported for the Geysers field. Finally, Unit 13 decline rates (MW loss) are projected for the various rates of steam withdrawal (generated MW) from the field to help estimate future field output, makeup well requirements, and field life.

FIELD DEVELOPMENT

The Geysers geothermal field is the world's largest commercially developed vapor dominated system with a present installed capacity of 2000 net MW (NMW). The Castle Rock springs area, which contains the wells used in this analysis, occupies the eastern part of the Geysers field, including the Units 13 and 16 wellfields (Figure 1). Fifteen power plants PG&E Units 9, 10, 13, 14, 16, 18, 20, NCPA 1 thru 4, SMUDGE0 #1, Santa Fe, Bear Canyon and West Ford Flat derive steam from The East Geysers which also includes the Castle Rock Springs area.

The initial development of the Geysers field started on its western side with installation of the first 11 NMW unit in 1960. The continued development during the next 20 years increased the total installed capacity of the field to 665 NMW (Figure 2). Most of this development remained confined to The West Geysers except Units 9 and 10 which utilize steam from the eastern part of the field to generate 106 NMW. During the 1980s, most of the development took place in The East Geysers as presented in Figure 2. The installed capacity of this part of the field increased by more than 10 times in less than 9 years.

The overall capacity of the Geysers field increased at a rate of about 8 MW/year during 1960-70, about 84 MW/year during 1970-80, and about 136 MW/year during 1980-88. Total field wide installed capacity of 2000 NMW was achieved by December 1988. The development in The East Geysers averaged at a rate of about 121 MW/year during 1980-88. The installed capacity in the East Geysers increased by 383 NMW (278 MW/year) and 347 NMW (694 MW/year) during the peak periods from January 1983 to May 1984 and October 1985 to April 1986 respectively (Figure 2). No new capacity was added in The East Geysers until the fourth quarter of 1988 when Bear Canyon (20 NMW) and West Ford Flat (27 NMW) came on line. Total installed capacity of 1132 NMW was achieved in The East Geysers by December 1988. The effect of this rapid development in The East Geysers on the performance of the unit 13 wellfield is described in the following sections.

RESERVOIR RESPONSE TO PRODUCTION

Well productivity is a strong function of the reservoir pressure. These two parameters are empirically related by the Back Pressure Equation given below (Earlougher, 1977).

$$W = C\,(Pr^2 - Pwb^2)^n \qquad (1)$$

Where,

- W = Steam flow rate, klbm/hr
- C = An empirical constant, often termed as productivity index which depends on reservoir and fluid properties, well condition and time
- Pr = Reservoir pressure, psia
- Pwb = Bottomhole flowing pressure, psia
- n = An empirically determined exponent, also known as turbulence factor with a value between 0.5 and 1.

As suggested by equation (1), large steam withdrawal from the reservoir is expected to induce a decline in the reservoir pressure which in turn reduces well deliverability.

In a steam reservoir, pressure can be affected locally as well as regionally. Local drop in the reservoir pressure and the resulting decline in the well production rate are the functions of the local mass of steam withdrawal from a given wellfield, pressure interference associated with well spacing and the reservoir characteristics. On the regional scale, steam withdrawal by various wellfields creates pressure gradients in the reservoir and pressure interferedce between wellfields. Steam flows from one wellfield to the other following the direction of the pressure gradient causing a decline in the well deliverability of the former due to the production of the latter. In this paper, we attempt to distinguish Unit 13 decline on the basis of local and regional decline concepts.

Unit 13, with 135 NMW capacity, is the largest geothermal plant in the world. It started generating electric power in May 1980 with only 18 producing wells. Within the next 2 months, two additional wells were added. The steam production history of these 20 wells is normalized by using equation (1) where Pr and Pwb are replaced by static wellhead pressure and a representative flowing wellhead pressure of 140 psig respectively. Exponent "n" is determined from the isochronal test for each well. These normalized flow rates for the last 9 years are presented in Figure 3. Normalized steam flow rates for the entire Unit 13 wellfield including makeup wells are also shown in this figure. Static wellhead pressures used in the Back Pressure Equation are changed at appropriate time intervals to reflect the prevailing reservoir pressures.

The timing of makeup wells in the Unit 13 wellfield and the start up of new power plants in The East Geysers are also indicated in Figure 3. Total normalized wellfield production of 2.7-2.8 million pounds of steam per hour was achieved until late 1984 with 5 makeup wells over the 4 year period, and including unit outages for plant overhaul and wellfield maintenance, and hydrocurtailment. This makeup well rate of 1.25 wells per year for a 135 NMW power plant is similar to the requirement of 1 well per year for each 100 MW unit in the western part of the field (Lipman et al., 1977). Two wells, drilled in late 1980 and early 1981, were to satisfy some contractual obligations rather than to make up for the steam shortage. High steam deliverability of greater than 3 million lbm/hr seen after plant outages is the result of flush production due to the buildup of reservoir pressure during shut-in (Figure 3).

Increasing decline rates, towards the end of 1984 or early 1985 resulted in additional steam being provided by a few wellbore scale cleanups and cross tieing three existing wells from the Unit 16 wellfield to the Unit 13 pipeline until the start up of Unit 16 in October 1985 (Figure 3). One makeup well CA 956A-6 was also drilled in Unit 13 wellfield in 1985. During the first' half of 1986, makeup wells were not drilled in the Unit 13 wellfield and the field was allowed to decline at the rates prevalent at that time until the second half of 1986 when makeup well drilling became necessary. A total of 6 makeup wells were drilled over a 20 month period during 1986-88 as shown in Figure 3. This rate of makeup drilling improved the steam deliverability situation to some extent but failed to keep up with the steam loss due to increasingly high decline rates. In fact, the net steam gain per well diminished with drilling of more makeup wells due to reduced well spacing and well interference. Makeup well drilling was stopped after March 1988 in an attempt to lessen decline rates by reducing the steam withdrawal rate from the reservoir.

Steam deliverability of the original 20 wells, presented in Figure 3, exhibits five basic decline trends during their entire 9 years of production history: an initial high level of decline rate followed by a moderate decline and then a high decline rate. The last two decline rates observed during 1987-88 are very high. These decline trends are influenced by local as well as regional steam production from the reservoir. An initial annual linear decline rate of 10.5% continues for about 18 months until December 1981 when the wellfield was shut-in due to a Unit 13 outage. This initial high decline always occurs in the Geysers wells before achieving a stabilized moderate rate. During this time (1980-82), The East Geysers had only four power plants in operation, Units 9, 10, 13 and 14 (Figures 1 and 2). Offset production from the three units apparently did not influence Unit 13 production since these units'are sufficiently distant from the Unit 13 wellfield. This suggests that the initial 10.5% linear decline rate in Unit 13 was a local decline.

During the next 2.5 to 3 years, the reservoir stabilized to a moderate annual linear decline rate of only 5% (Figure 3). This moderate decline rate was a result of field stabilization, unit outages, and a moderate makeup well drilling program. During 1983-84, new projects such as PG&E Unit 18 (113 NMW), NCPA 1 and 2 (118 NMW), SMUD (72 NMW) and Santa Fe (80 NMW) came on line (Figures 2 and 3). The effect of this 383 NMW of new capacity in the adjacent areas was not noticed in Unit 13 wellfield until early 1985 (Figure 3). Therefore, the moderate linear decline of 5% in Unit 13 can also be regarded as a decline affected only by local factors.

In early 1985, Unit 13's annual linear decline rate increased to 8.5%. This higher decline is probably the combined result of local and regional steam withdrawal effects. By this time, the pressure wave and the resulting drawdown created by the operation of the newly developed wellfields (383 NMW capacity) seem to have reached the Unit 13 area. Steam loss due to this increased decline was compensated by bringing steam from the Unit 16 wells and by drilling three new makeup wells in 1985-86 (Figure 3). Six wells, out of the original 20 wells, were cleaned out during 1985-86. Wells CA 958-3, D&V-2 and CA 956-1, cleaned out during September 1985, provided an additional steam of about 280 klbm/hr. Cleanout of wells CA 956A-4, Thorne-1 and D&V-1 in April 1986 further increased steam supply by about 45 klbm/hr. These increased steam deliverabilities are included in the data shown in Figure 3.

The highest annual linear decline of 25.7% began in late 1986 or early 1987. By this time, The East Geysers was burdened with an additional capacity of 347 NMW which went into operation during 1985-86. This included PG&E Units 16 and 20, and NCPA Units 3 and 4 (Figures 2 and 3). This new capacity contributed to the further increase in regional decline. A high rate of makeup wells (4 wells in 8 months) could not compensate for the steam decline and in fact, adversely affected it by increasing interference between wells due to reduced well spacing. The high annual linear decline rate of 25.7% continued through early 1988 and appears to be the combined result of regional decline due to a large steam withdrawal rate associated with new and old offset capacity, and local decline due to increased interference related to reduced well spacing. Decline rates moderated to 19.6% in 'the second half of 1988 due to the combined effect of reduced steam production, Unit 13 outage in May 1988 and no makeup well drilling after March 1988 (Figure 3).

A semilog plot of total flow rate normalized to 140 psig and the flow rate without makeup wells versus time is presented in Figure 4. Annual exponential decline rates (De) for the described trends are 11.5%, 5%, 9%, 28.6% and 24% respectively. Linear (Dl) and exponential (De) decline rates are related by equation (2).

$$Dl = De((Wt/Wo)-1)/\ln(Wt/Wo) \qquad (2)$$

where,

Wo = Initial steam flow rate, klbm/hr
Wt = steam flow rate at time t, klbm/hr
t = time interval, years

An alternative form of equation (2) is given below.

$$Dl = (1- \exp(-De\ t))/t \qquad (3)$$

It may be noticed that makeup wells provided additional steam of about 1 million pounds per hour towards the end of 1988 (Figure 4).

TYPE OF DECLINE TREND IN THE UNIT 13 WELLFIELD

A log-log plot of production rate from the original 20 wells versus time is presented in Figure 5 to determine whether these wells declined harmonically, hyperbolically or exponentially. This data set is matched against type curves developed by Fetkovich (1980) for various valued of the exponent "b". A data trend which matches b=O indicates an exponential decline. Harmonic decline trend is represented by b=1. All decline trends between b=O and b=l are termed as hyperbolic decline.

A type curve match of the data, illustrated in Figure 5, represents a harmonic decline trend up to December 1986 (2405 days). Beyond this time, the flow rate drops sharply as explained earlier in the discussion of Figure 3. Data points, presented in Figure 5, are reinitialized after 2405 days (Enedy, 1989). A type curve match with this data set indicates an initial near exponential decline trend which shifts towards hyperbolic harmonic trend due to unit outage, reduced capacity and ceasing of makeup well drilling in early 1988 (Figure 5). Unlike Ripperda and Bodvarsson (1987) and Enedy (1987), this observation suggests that an exponential or near exponential decline is possible in The Geysers field at least during transient conditions.

DECLINE TREND COMPARISONS

A plot of steam flow rate ratio versus time for the original twenty Unit 13 wells is presented in Figure 6. Steam flow rate ratio is defined as the ratio of the normalized steam flow rate of the 20 wells at a wellhead pressure of 140 psig at a given time, to the initial normalized flow rate of those wells. at Unit 13's start up in May 1980. For comparison, the decline trends presented by Budd (1972), Stockton et al.,(1984), and Ripperda and Bodvarsson (1987) are also reproduced in Figure 6.

Initial decline of Unit 13 wellfield matches with Stockton et al.'s 12.5% harmonic decline rate for the first 18 months. During the next 2 years, Unit 13's decline agrees well with both the 40 acre spacing case of Ripperda and Bodvarsson (1987) and the 20 acre case of Budd (1972). Allowing for data scatter, it can also be argued that Unit 13 trend for the first 3-1/2 years since start up is approximately close to the 40 acre spacing case of Ripperda and Bodvarsson (1987). During these years average well spacing in the Unit 13 wellfield and its southwest portion remained between 35 to 42 acres and 26 to 34 acres respectively. Unit 13's decline rate accelerated toward the beginning of 1985 due to regional steam withdrawal and increased still further by December 1986 due to the combined effect of local add regional drawdowns. Reinitialization after December 1986 (2405 days) displays a decline rate higher than Budd's 5 acre spacing case (Figure 6). During this period (1987-88), the Unit 13 wellfield and its southwest portion had an average well spacing of 27 to 32 acres and 19 to 21 acres respectively. This suggests that for a well spacing of 19-32 acres the decline in the Unit 13 wellfield is higher than the decline estimated by Budd (1972) for the 5 acre spacing. A reservoir decline which follows Budd's 20 acre trend is considered reasonable by Sanyal (1985) for the western part of the Geysers field. This assessment appears to be optimistic considering Unit 13's decline trend shown in Figure 6. In summary, decline rates associated with local drawdown match approximately with the 40 acre spacing case presented by Ripperda and Bodvarsson. However, the combined effect of local and regional drawdowns increase decline rates considerably higher than reported so far in the literature for the Geysers field.

MW LOSS VERSUS TOTAL GENERATING CAPACITY

Decline analysis, as discussed, is utilized to analyze decline rates at various rates of steam withdrawal from the reservoir. Such information should be helpful in estimating future field output, makeup well requirements, and field life. Figure 7 presents such a plot where Unit 13 and 16 wellfields are considered as one. Initial average steam withdrawal of 2.47-2.59 million lbm/hr during 1980-84 caused a stabilized annual exponential decline rate of 5% as shown in Figure 4. Offset development caused further pressure drawdown in the reservoir in 1985-86, increasing decline rates to 9% in the Unit 13 area. An increase of 80% in decline rate is attributed to the regional drawdown created by the offset production. A 28.6% annual exponential decline occurred due to local and regional drawdowns for the production rates of 4.44 to 4.69 million lbm/hr which includes Unit 16 steam production of about 2 million lbm/hr. Reduced well spacing associated with the high rate of makeup well drilling assisted this high decline rate by creating more interference between the wells. Reduced steam production along with no makeup well drilling program eased decline rates to 24% for the combined production of 4.05-4.45 million lbm/hr from the Unit 13-16 area (Figure 7). As a first approximation, the decline trend can be obtained by connecting the two points by a straight line. Intermediate data points are needed to determine the trend accurately. Figure 7 suggests that decline rate is more sensitive to total rate of steam withdrawal from the reservoir than makeup drilling. Figure 7 also suggests that the Unit 13-16 wellfield should be produced at about 3.2 million lbm/hr to achieve an annual exponential decline rate of about 15%.

Figure 8 presents a plot in terms of MW decline versus net generating capacity in the Unit 13-16 areas. In developing this figure, it is assumed that both Units 13 and 16 decline at the same rate. Annual decline of 6 MW in Figure 8 represents a local decline in the Unit 13 area for a generation of 123 to 125 NMW. Local and regional effects enhanced Unit 13 decline losses to 10.5 and 11 MW for the generating capacity of 121 and 129 NMW respectively. Capacity decline of 58 to 61 MW per year at generation levels of 234 to 247 NMW respectively, represents total loss which includes local, regional and accelerated makeup well drilling effects. These losses diminish to 43 to 46 MW per year in response to a reduced generation load of 201 to 218 NMW without further makeup well drilling. A straight line extrapolation is used in Figure 8 due to the lack of data for intermediate points. This figure suggests that MW loss is strongly dependent on the generating capacity. Additionally, offset production increased the loss by about 75% when only Unit 13 was producing. This figure also indicates that a generation of about 160 NMW should reduce decline related loss to about 2 MW per month assuming that the current conditions of offset production continues.

The effect of total generating capacity in The East Geysers on the annual MW decline in the Unit 13-16 area is presented in Figure 9. This figure suggests that annual MW decline in Unit 13-16 area increases from 6 MW to about 10.5 MW in response to an increase in the generating capacity in The East Geysers from 355 to 738 NMW (Figures 2). A further increase in the generating capacity to 1085 NMW enhances Unit 13-16 annual decline to 58-61 MW (Figure 9). Steam shortage of 198 MW (Units 9, 10, 13, 14, 16, 18, 20, and NCPA Units 1 thru 4) and the new installed capacity of 47 NMW (Bear Canyon and West Ford Flat) resulted in an actual generating capacity of 934 NMW in the second half of 1988 in The East Geysers. At this generation level Unit 13-16 experienced an annual decline of about 43-46 MW as shown in Figure 9. This figure implies that at an actual generating capacity of about 830 NMW in the East Geysers area, Unit 13-16's decline should be limited to about 2 MW per month.

CONCLUSIONS

Decline behavior of Unit 13's wellfield is explained by the decline analysis of the normalized deliverability of 20 wells which supply steam to the Unit 13 power plant since its start up in May 1980. Five different decline trends have been observed in the Unit 13 wellfield over its 9 year production history. These trends are defined as local and/or regional depending upon the apparent source of decline. A local decline is caused by the pressure interference between the wells in a given wellfield. On the other hand, pressure decline caused in the Unit 13 wellfield due to offset production is defined as the regional decline. Initially, the field underwent a local high decline at an annual exponential rate of 11.5% for the first 18 months. Thereafter, Unit 13 wellfield stabilized at an annual exponential decline rate of 5% which continued up to late 1984. The effect of 383 NMW of offset production increased Unit 13 decline rates to 9% through about December 1986. The start up of Unit 16 and 234 NMW of offset production in late 1985 and early 1986 created further pressure drawdown in the Unit 13 reservoir and increased decline rates to an all time high by late 1986 or early 1987. High declines of 28.6% in 1987-88 are the result of local and regional steam withdrawal as well as the accelerated makeup well drilling program. In late 1988, it moderated to 24% due to the combined action of reduced overall capacity, Unit 13 outage and the absence of makeup well drilling in the Unit 13-16 area.

Unit 13 displays a harmonic decline trend prior to December 1986. The start up of Unit 16 and the increase in offset capacity coupled with an accelerated makeup well drilling program changed the initial harmonic decline .trend to an exponential or near exponential trend (Figure 5). Reduced capacity without makeup wells has moderated decline to a nearly hyperbolic-harmonic trend. As per the authors' knowledge, an exponential trend has not been reported to date for the Geysers field.

A harmonic decline trend associated with local drawdown in the Unit 13 wellfield at a well spacing of 26-42 acres matches the 40 acre spacing trend presented by Ripperda and Bodvarsson.. Unit 13's decline at 19-32 acre spacing is higher than the 5 acre spacing of Budd (1972) and Ripperda and Bodvarsson (1987). Sanyal's preference (1985) for harmonic decline, utilizing Budd's 20 acre curve to characterize decline trends in The 'Geysers, appears optimistic considering Unit 13,s data. Decline trends can not be explained by considering only the well spacing. Both local and regional steam withdrawals should be considered in addition to well spacing to obtain decline trends.

Preliminary plots of MW loss due to deliverability decline versus actual generating capacity have been prepared to facilitate estimates of future field output, makeup well requirements and field life. These figures suggest that a capacity of 160 NMW in the Unit 13-16 wellfield and 830 NMW in the East Geysers area should reduce Unit 13-16 decline to about 2 MW per month.

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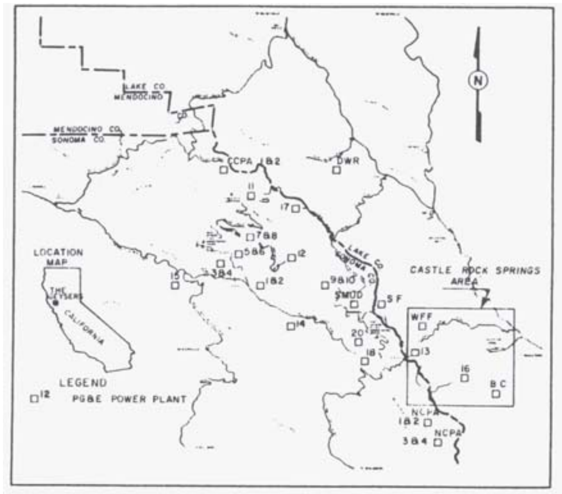

FIGURE 1: The location map.

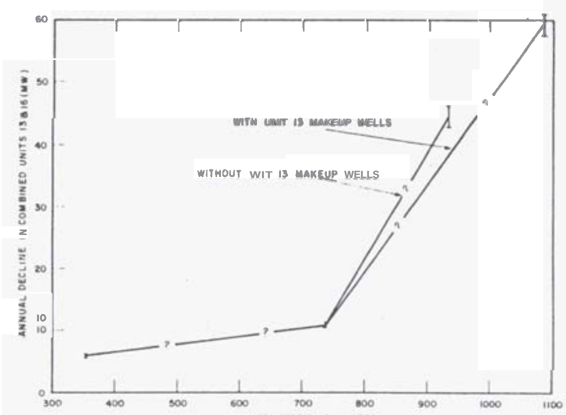

FIGURE 9: Actual generating capacity in The East Geysers versus MW decline in Unit 13-16 area.

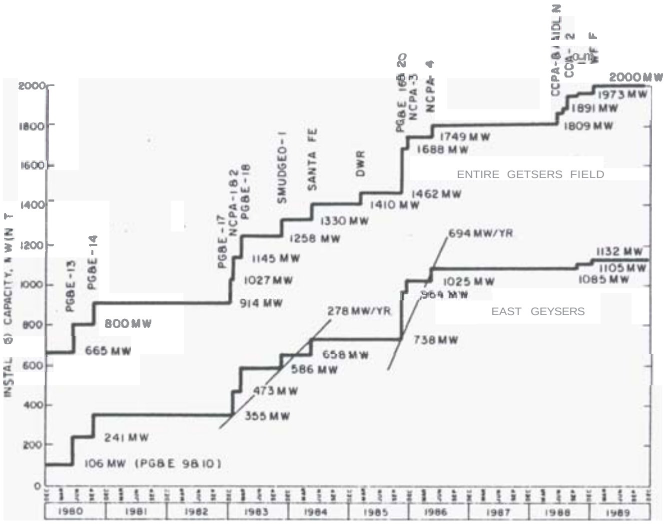

FIGURE 2: Growth of The Geysers field.

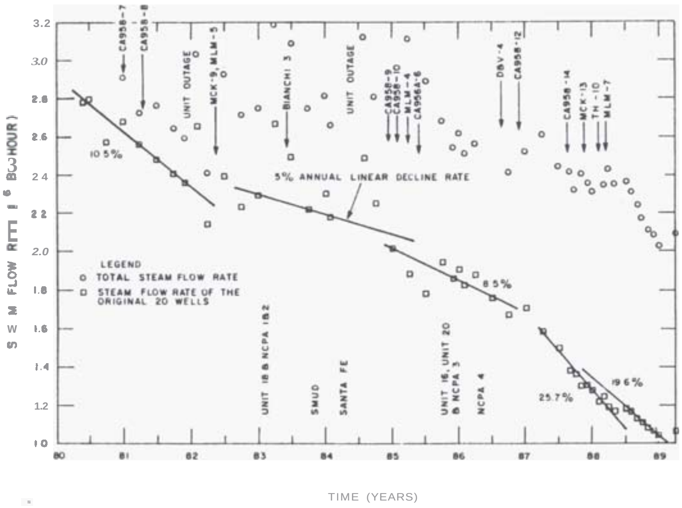

FIGURE 3: Unit 13 produciton history, makeup wells and linear decline trends.

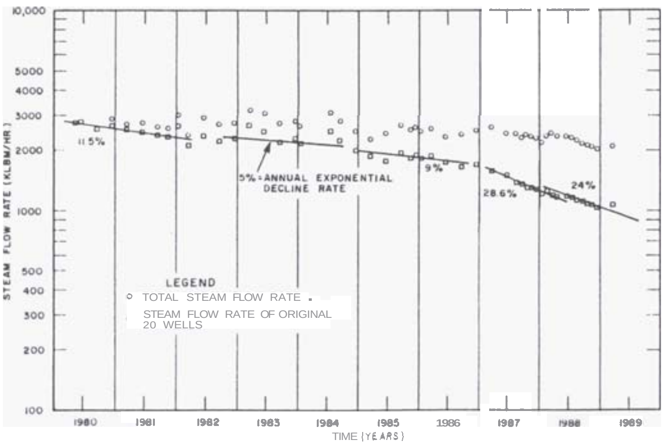

FIGURE 4: Exponential decline reates in Unit 13 wellfield.

FIGURE 8: MW decline versus generation capacity in Unit 13-16 wellfield.

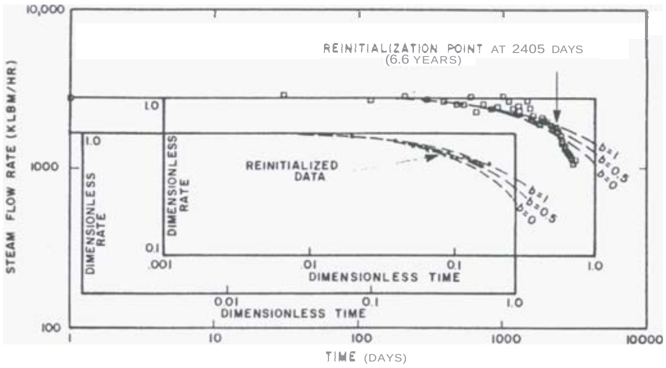

FIGURE 5: Type curve match for Unit 13 decline trends.

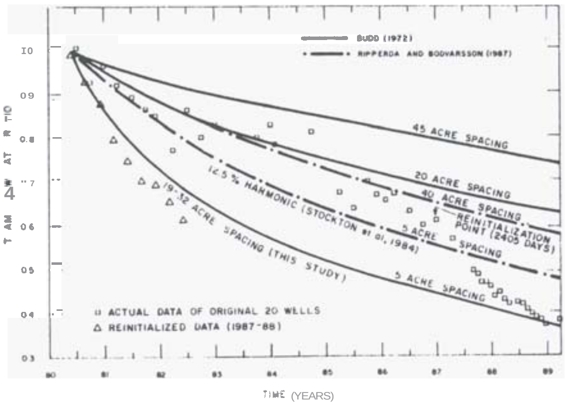

FIGURE 6: Comparison of Unit 13 decline trends with other reported trends in The Geysers.

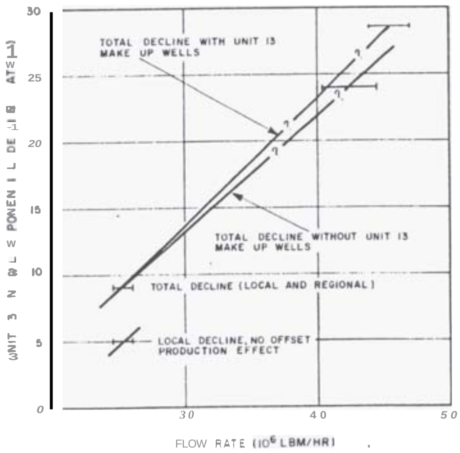

FIGURE 7: Local and regional decline in Unit 13 wellfield.