PROCEEDINGS, Tenth Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, January 22-24, 1985
SGP-TR-84

Flow Rate Decline of Steam Wells in Fractured Geothermal Reservoirs

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INTRODUCTION

Decline curves are commonly used at The Geysers geothermal field to assess the generating capacity of a producing lease. It is generally assumed that wells will initially be drilled using 40-acre (400 m) spacing, with infill drilling used later to provide additional producing wells as needed. It is commonly believed that the final well spacing should not be less than 10 acres (200 m). Decline curves are used with this approach to estimate the number of make-up wells during a project lifetime (up to 30 years), as well as the appropriate plant size (MWe).

Problems arise when one must choose the proper decline curve method because there does not appear to be a sound basis for choosing between the standard types of curves (hyperbolic, harmonic or exponential). Budd (1972) published theoretical decline curves for The Geysers, but it is not clear how he derived these curves (Fig. 1). Dykstra (1981) developed an average decline curve based on production data available in the open literature. Lack of data made it necessary for Dykstra to average results from wells with different spacings to obtain a single decline curve; this limits the applicability of his result. Aside from these results, there are no published decline curves for The Geysers that take into account variability in the parameters controlling production decline, such as permeability, porosity, and fracture spacing.

In this paper we use a rather simple two-dimensional model to investigate the factors that control flow rate decline in steam wells. The effects of parameters such as fracture spacing and permeability are considered, as well as the effects of permeability, porosity and initial liquid saturation in the rock matrix. Also, the conventional P/z method that is commonly used in analyzing gas well production is investigated in terms of its applicability to fractured vapor dominated systems. We are not able to propose a new set of decline curves for The Geysers, because it would require combining the approach used in this work with that of Dykstra (1981). This is not possible because of a lack of published data.

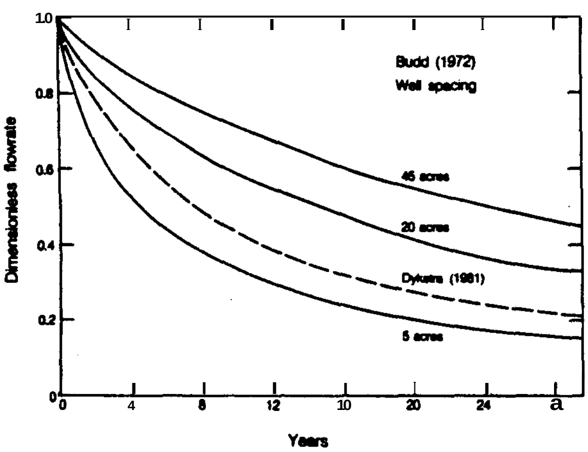


Figure 1: Theoretical and empirical decline curves for Geyser's wells.

APPROACH

In the study we use a two-dimensional areal model that considers the symmetry of a well field with 40-acre spacing (Fig. 2). The model can also be used to simulate 20- and 10-acre spacing by placing additional wells in the corner(s) of the symmetry element. This allows the well spacing to be changed (e.g., 40- to 20- to 10-acre spacing) during the simulation without changing the grid block structure. In the simulations, we employ the MINC method (Pruess and Narasimhan, 1982) for modeling the fracture characteristics of the reservoir, and use the basic Warren and Root (1983) model with three sets of orthogonal fractures. It is believed that highly-conductive fractures are often near-vertical at The Geysers field but that horizontal fracture permeability is also significant (Thomas, 1981). According to Weber and Bakker (1981). a fracture porosity of 1% is a reasonable average value for Graywacke. The average fracture spacing is varied in the simulations.

Both the fractures and the rock matrix are subdivided into volume elements; fluid and heat flow in the fractures is represented by a two-dimensional grid block network. Each fracture element is then

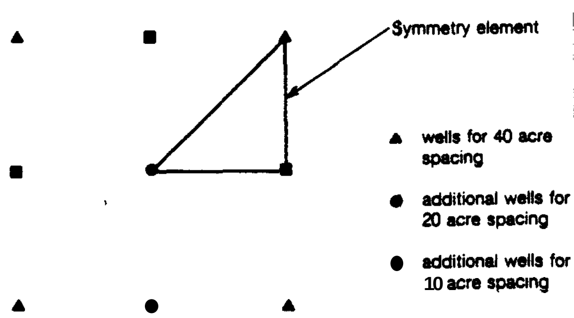


Figure 2 Symmetry element used in the simulations.

connected to a string of elements representing the rock matrix. Thus, the computational effort is similar to that for a three-dimensional porous medium model. A total of 38 grid blocks is used for the fracture network, with nine rock matrix volume elements per fracture element; the total number of volume elements is 380, with 560 connections between them. The large number of rock matrix grid blocks is necessary in order to resolve large pressure and temperature gradients that develop in the rock matrix during exploitation.

The MULKOM simulator developed by Pruess (1982) was used in the study, but the effects of capillary pressure and vapor pressure lowering due to liquid adsorption are neglected. Capillary pressure may be important in the low permeability Graywacke, but we are not aware that such data are available for this rock unit. By assuming that steam is fully mobile ($K_{rv}=1$) and water in the rock matrix is immobile ($K_{rl}=0$), relative permeability curves are not needed. Pruess and Narasimhan (1982) have shown that even if the rock matrix contains high liquid saturation, the liquid will boil off to steam before entering the fractures, if the effective rock matrix permeability is sufficiently low. In the following discussion, the effective matrix permeability will denote the product kk_{rv} (permeability x relative permeability of steam phase).

The flow rates from the wells are calculated based upon a deliverability model commonly used in the gas industry:

$$q=C(P_r^2-P_{wb}^2)^n \qquad [1]$$

where C and n are often assumed to be constants, P_r is the reservoir pressure and P_{wb} is the bottomhole flowing pressure. The C-factor is a typical fudge factor that depends on various parameters such as reservoir and fluid properties, well condition. and time (Budd. 1972). Here, however, we assume that the C-factor is a constant for a given case, but it is allowed to vary between different cases. The n-factor is held constant at 0.75; this value has been found to work well for some Geysers wells (A. Drenick, personal communication 1984). Other constant parameters are given in Table 1. Note that we assume a very large reservoir thickness (3500 m) which is consistent with geological data (Thomas, 1981) and reservoir engineering estimates (Dykstra. 1981). It should be noted that a major approximation in this work is the neglecting of gravity for such a thick reservoir. This approximation is based on the assumption that in spite of the large vertical dimension of the reservoir, the pressure drop will be largest in the rock matrix because of its low permeability. Other parameter values assigned to the Graywacke are given in Table 1.

Table 1. Parameters held constant in the simulations.

Rock density:	$2650 kg/m^3$
Heat capacity:	1000 J/kg
Thermal conductivity:	$3.0 W/m^\circ C$
Reservoir thickness:	3500 m
Fracture porosity:	1%
Initial pressure:	37.5 bars (corresponding to 245° C)
Bottomhole pressure:	17.5 bars
n-factor:	0.75
Relative permeabilities:	$k_{rl}=0\ k_{rv}=1$.

BASE CASE

In the development of an appropriate base case. we try to simulate an average well at The Geysers field. The parameter values used are given in Table 2 (see also Table 1). We assume that an average well initially produces some 16 kg/s (125,000 lbs/hr) of steam (A. Drenick. personal communication. 1984). and that it has a fracture transmissivity of 15 Darcy-meters (Dm; 50.000 md.ft) and a skin of -4 (equivalent radius of ~ 20 m). Furthermore, we assume that average fracture spacing in the reservoir is 100 m. which is reasonable based upon the number of steam entries for an average well (Dykstra. 1981). Most of the other parameter values are taken as assumed by Dykstra

Table 2. Parameter values used for the base case*

Initial liquid saturation:	50%
Fracture transmissivity:	15 Dm (50.000 md.ft)
Effective matrix permeability:	$5 x 10^{-3} md$
Fracture spacing:	100 m
Matrix porosity:	8%
C-factor:	$42\ 10^{-10} (kgs^{-1} pa^{-1.5})$
Well spacing:	40-acre

*Note also values for constant parameters given in Table 1.

(1981). The value for the C-factor is adjusted until the right initial flow rate is achieved (~120.000 lbs/hr) and the effective matrix permeability (kk_{rv}) is adjusted until a reasonable flow rate decline result. Figure 3 shows the flow rate decline for 30 years for the base case; for comparison, we also include the results of Budd (1972) for 20- and 45-acre spacing. The decline rate for our base case (40-acre spacing) is somewhat higher than the theoretical results given by Budd.

Table 3 summarizes the different cases simulated and the parameter values used. Note that only the parameter value that differs front the value used in the base case (Table 2) is given. The results of these simulations are discussed below, especially with respect to flow decline, cumulative production and the P/z method of analysis.

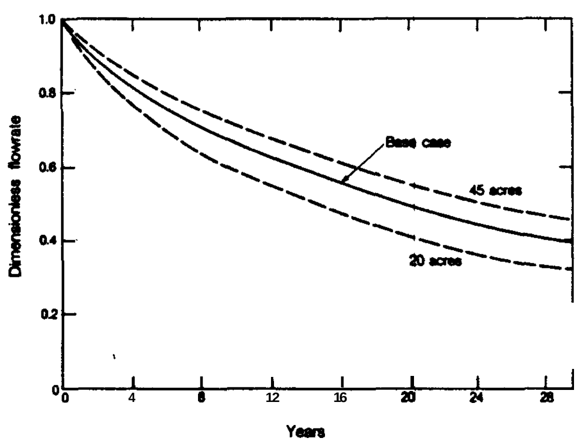


Figure 3: Flow rate decline of the base case and comparison with results of Budd (1972).

Table 3. Different cases simulated.

Case #	Parameter value	Comments
0		Base case
1	$(kh)_f = 45 Dm (150{,}000 md.ft)$	High fracture permeability
2	$(kh)_f = 5 Dm (16{,}000 md.ft)$	Low fracture permeability
3	$k_m k_{rv} = .015 md$	High effective matrix permeability
4	$k_m k_{rv} = .0017 md$	Low effective matrix permeability
5	$S_l = 0.80$	High initial liquid saturation
6	$S_l = 0.20$	Low initial liquid saturation
7	$C = 8x\,10^{-10} kgs^{-1} pa^{-1.5}$	High C-factor
8	$C = 22\,10^{-10} kgs^{-1} pa^{-1.5}$	Low C-factor
9	FS = 500 m	Large fracture spacing
10	FS = 20 m	Small fracture spacing
11	40- to 20- to 10-acre spacing	15 years each
12	40- to 20-acre spacing	10 years each
13	20-acre spacing	For 30 years
14	10-acre spacing	For 30 years
15	$\phi = 1\%$	Low matrix porosity

FLOW RATE DECLINE

In comparing the flow rate decline for the different cases, we assume that after one month the wells have reached a stable initial rate (100%), which of course may vary for the different cases. As expected, the parameters that have the most pronounced effect on flow rate decline are effective matrix permeability, fracture spacing and initial liquid saturation (Fig. 4). The fracture spacing and the effective matrix permeability are related parameters that control the fluid recharge from, the matrix into the fractures; actually these parameters can be combined into a single unique parameter, $(k_m)_{eff}/(FS)^2$. The mass of liquid water in-place (S_l) controls the time scale of the depletion front (S_v=1) moving into the rock matrix from the fractures. The lower the initial liquid saturation, the faster the depletion front moves into the rock matrix, causing large pressure drops in the rock matrix, and hence, a rapid flow decline.

The initial (early time) flow rate is primarily controlled by the C-factor. as seen in Table 4. The C-factor includes the effects of the complicated near-well phenomena that very strongly controls the early mass flow rate. Other factors that also effect the early mass flow rate are the fracture permeability, and to a lesser extent, the fracture spacing. Certainly, if the equilibrium period for stable flow is assumed to be larger than one month, recharge from the rock matrix will become important and the effective matrix permeability will also affect the early

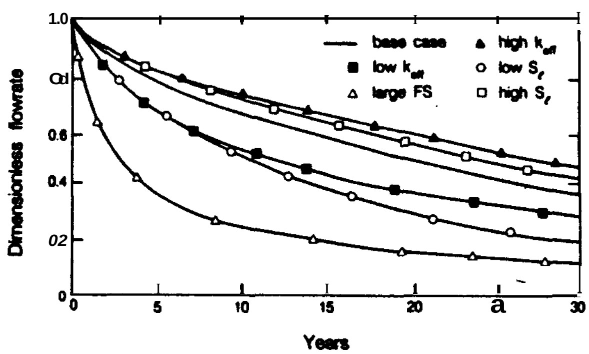


Figure 4 Effects of initial liquid saturation, fracture spacing (FS) and effective matrix permeability on the flow rate decline (40-acre well spacing).

flow rate. At still later times, the well spacin becomes important. Although the C-factor greatl affects the early flow rate values, the long term rate i practically independent of the C-factor, as shown i Figure 5. The late time flow rate decline is controlle by rock matrix properties and the fracture spacing.

In the above discussion we have only considere the case of 40-acre spacing; the flow rate declint obviously, also depends upon the well spacing. Figur 6 shows the flow rate decline for diderent well spac ings. Obviously, individual wells will decline faster well spacing is reduced, because of well interference Additional wells will help extract more steam fron the reservoir in a given time period. However, if wel spacing is too small, the additional steam obtaine through drilling of wells may not be sufficient to repa the costs of investment.

Figure 7 shows the cumulative steam produce versus time for the three different well spacings. A the end of 30 years, the cases for 10- and 20-acr spacing yield 37 and 25% more steam than the 40-acr case, respectively. Actually, these gains appear to b marginal considering the investments that would b required. With 10-acre spacing, four times more well must be drilled than with 40-acre sphcing. This sug gests that, in the case of a vapor dominated reservoir long-term well interference will have a tendency t offset the beneficial effects of infill drilling.

Table 4. Initial (1 month) stable flow rate for the different cases.

Case #	Case description	Initial flow rate (kg/s)
0	Base Case	16
1	High fracture permeability	18
2	Low fracture permeability	13
3	High matrix permeability	16
4	Low matrix permeability	16
5	High liquid saturation	16
6	Low liquid saturation	16
7	High C-factor	28
8	Low C-factor	9
9	Large fracture spacing	14
10	Small fracture spacing	18
11	40- to 20-acre spacing	16
12	40- to 20- to 10-acre spacing	16
13	20-acre spacing	16
14	10-acre spacing	16
15	Low matrix porosity	16

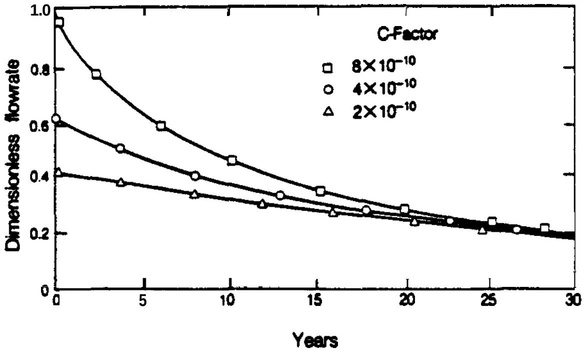


Figure 5: Effects of the C-factor on the flow rate decline; the flow rate is scaled by the initial flow rate of the case with $C=8 \times 10^{-10}$.

The results for Case 12 show the effects of decreasing the spacing every 10 years from 40- to 20- to 10-acres. The results are very similar to those obtained in Case 13, which used 20-acre spacing over the entire 30-year period. This suggests that time-averaged well spacing can be used for long term predictions. The results for Case 11 (40- and 20-acre spacings for 15 years each) fall between those of 20- and 40-acre spacings, as one would expect.

It is also interesting to compare the total mass of steam produced for each of the different cases simulated. Figure 6 shows the cumulative production versus time for each of the cases studied, and Table 5 summarizes the results at the end of the 30-year production period. As one might expect, the table shows that the most steam is produced for those cases with a high fracture or matrix permeability, a high well deliverability (C-factor), or a small fracture spacing. It is interesting to observe that when the fracture spacing is large, only a small fraction of the steam reserves can be recovered in 30 years.

P/z METHOD OF ESTIMATING RESERVES

The P/z method of analysis has been used for many years in assessing reserves for natural gas fields. In this method, the average reservoir pressure, P, is divided by the gas deviation factor, z, and a plot of P/z versus cumulative gas produced yields a straight line for closed reservoirs. An extrapolation of this straight line to the field abandonment value for P/z makes this method an easy and rapid procedure for estimating reserves. This method of analysis has been applied to The Geysers (Ramey. 1970). the Gabbro zone at Larderello (Brigham and Neri, 1979), the

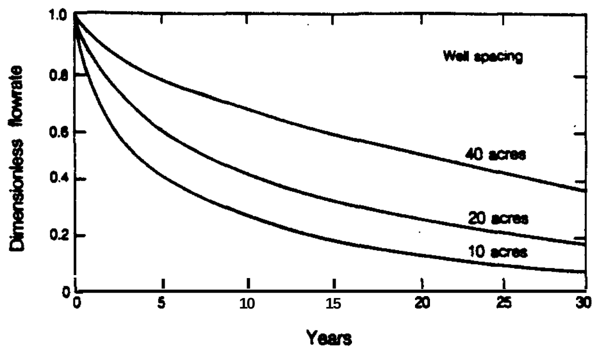


Figure 6: Effects of well spacing on the flow rate decline.

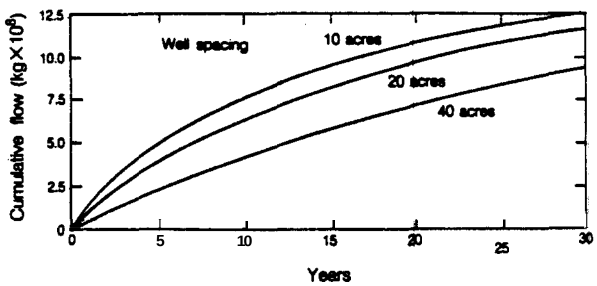


Figure 7: Cumulative flow for different well spacing.

Serrazzano zone at Larderello (Atkinson et al.. 1978), and the Bagnore geothermal fleld in Italy (Atkinson. et al., 1978).

The applicability of the P/z method to vapor. dominated geothermal systems has been investigated by Brigham and Morrow (1977) and Pruess et al. (1979). Brigham and Morrow use a lumped-parameter porous medium model to show that the accuracy of the method depends on the magnitude of the average porosity. If the porosity is near 10%, good estimates of steam reserves can be made. but if the porosity is as low as 5% or as high as 20%, the reserve estimates will be optimistic or pessimistic by a factor of 2, respectively. Pruess et al. (1979) point out that for boiling reservoirs, the pressure drop due to production does not depend on the fluid density, but rather on the temperature drop, which is directly proportional to the boiling rate. They also use a simple lumped-parameter model to show that the steam reserve estimates could be in error by orders of magnitude. For a system with low porosities and low liquid saturations, the reserves will be underestimated. In view of these differences we decided to investigate whether the P/z method could be applied to the results from our fracture model.

The results of our investigations show that indeed a Cartesian plot of P/z versus cumulative production (or equivalently. the mass fraction produced

Table 5. The total cumulative steam produced versus time for the different cases.

Case #	Description	Total steam produced ($kg \times 10^9$)
0	Base case	0.9
1	High fracture permeability	1.00
2	Low fracture permeability	0.80
3	High matrix permeability	1.05
4	Low matrix permeability	0.75
5	High liquid saturation	0.98.
6	Low liquid saturation	0.68*
7	High C-factor	1.10
8	Low C-factor	0.65
9	Large fracture spacing	0.35
10	Small fracture spacing	1.10
11	40- to 20-acre spacing	1.04
12	40- to 20- to 10-acre spacing	1.12
13	20-acre spacing	1.15
14	10-acre spacing	1.25
15	Low matrix porosity	0.25*

*These cases have different initial fluid mass in place.

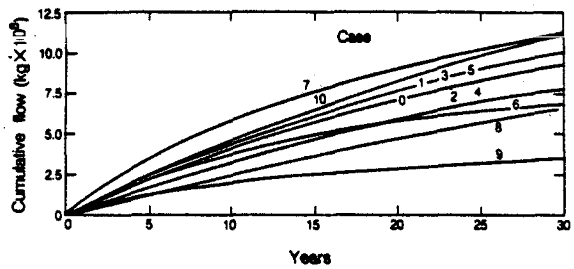
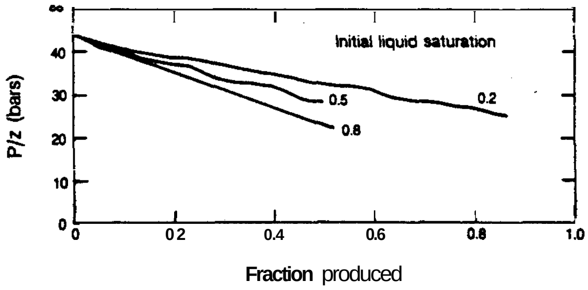


Figure *8:* Cumulative flow for the diberent cases with 40-acre well spacing. Table **3** gives descriptions of all cases.



Wgure 10: P/z plots for cases with different initial liquid saturation.

generally exhibits a straight line. Figure 9 shows results obtained for three different well spacings: 40-, 20-, and 10-acres (Cases 0, 13, 14. respectively). All three curves have a more or less straight line segment, and all the slopes are very similar. However, use of the P/z method for these three cases results in a 50%overestimation of the reserves.

When the initial liquid saturation in the matrix and the fracture spacing are varied, **an** even greater variability in the reserve estimates results. Figure 10 shows that the lower the initial liquid saturation, the more optimistic the reserve estimates. This finding is qualitatively in agreement with that of Pruess et al. (1979) although we flnd much less dependence on liquid saturation. It is interesting to observe that when $S_\ell = 0.8$, the reserve estimate **is** quite good; whereas, when $S_\ell = 0.2$, the reserves are overestimated by a factor of 2.

Figure 11 shows that fracture spacing can also have a very marked effect on the P/z method of estimating reserves. It is quite apparent that as the fracture spacing decreases, estimates of reserves are increased significantly. We have chosen fracture spacings varying from 20 to 500 m, in **an** attempt to model reservoir conditions at The Geysers, and it appears from the results on Figure 11 that one can under- or overestimate reserves by a factor of two depending on the actual fracture spacing.

Finally, we turn to the effects of matrix porosity because both Brigham and Morrow (1978) and Pruess et al. (1979) indicate that the accuracy **of** reserve estimates using the P/z method are greatly dependent on this parameter. Figure 12 shows the effect on the P/z plot of reducing matrix porosity from the base case of 8% to 1%. Our results are in agreement with those of earlier investigators that as the porosity decreases, reserve estimates become more optimistic. However, our results show much less dependence on porosity than reported by others (Pruess, et al., 1979). The results of the various cases analyzed in this study of the P/z method are summarized in Table *8.*

From the theoretical standpoint, the P/z method is not applicable to **a** vapor-dominated, two-phase system because, in constrast to natural **gas** reservoirs, the pressure drop is independent of the fluid density. ***As*** illustrated in Figure 13. results from this method of analysis could be seriously in error. If the matrix permeability is high and/or the fracture spacing is small, the reserves can easily be extracted from the matrix, mthout a significant pressure drop (upper curves) until a pure vapor phase develops. On the other hand, if the matrix permeability is low and/or the fracture spacing is large, fluid recharge from the matrix is hindered and pressures in the fracture system decrease rapidly (lower curves) leading to very conservative reserve estimates.

However, one should note that in spite of the range in reservoir parameters here, the calculated results using the P/z method are not **ob** by more than a factor **of** 2. **Thus.** if we have used the correct range of Parameters generally applicable for The Geysers, then from a practical standpoint, one should be able to use the P/z method for the first rough estimates of reserves in this field.

FIELD EXAMPLE

Dykstra (1981) gives production decline curves for eleven Geysers wells; the curve for GDC-85-12 is reproduced on Figure 14. The flow decline for this 40-acre well is very similar to that for Case *3* (base case with low effective matrix permeability). However, there are many other combinations of parameters that will also give similar flow rate decline. We have matched the decline data by varying the most important parameters: initial liquid saturation, fracture

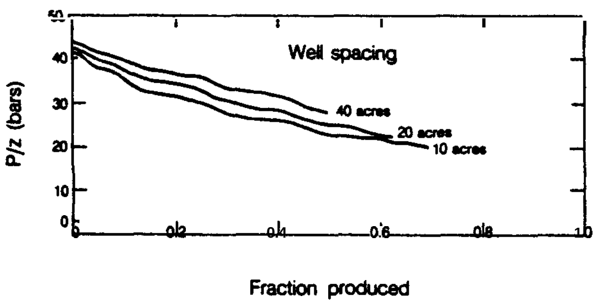


Figure 9 P/z plots for cases with different well spacing.

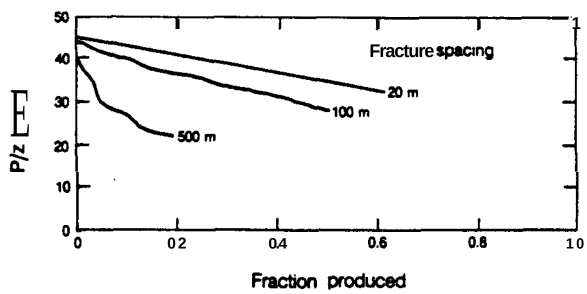


Figure 11: P/z plots for cases with different fracture spacing.

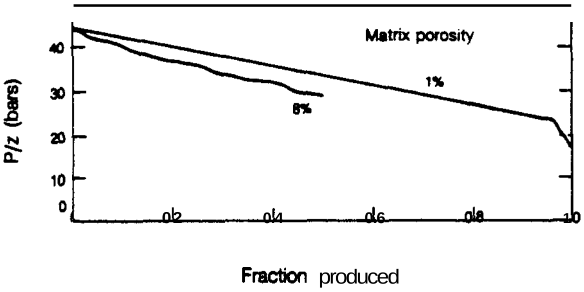


Figure 12 P/z plots for cases with different matrix porosity.

spacing and matrix permeability. All other parameters are the same as the base case with one exception. The C-factor is changed to 5.5×10^{-10} in order to match the initial flow rate of the well. In matching the flow rate data, we assume various initial liquid saturations (20, 50 or 80%) and vary the parameter $(k_m)_{eff}/(FS)^2$ until a reasonable match is obtained. This parameter eflectively controls the recharge rate from the matrix into the fractures, as has been reported by other investigators of naturally fractured reservoirs (Warren and Root, **1963;** Da Prat et al., 1981). Figure **15** shows that the value of the fluid recharge factor, $(k_m)_{eff}/(FS)^2$ that is needed to match the fleld data varies by a factor of 3-4 over a range of initial liquid saturations from 20% to 80%. Note, however, that for high initial liquid saturation, the variation in the fluid recharge factor is less than at low initial liquid saturations. Most people believe that the **initial** liquid saturation in the rock matrix at The Geysers fleld is in excess of 50%, in which case the appropriate fluid recharge factor for well GDC-85-12 is approxiately 1.5×10^{-22}.

Table 6 R[illegible]ult [illegible] P/[illegible] i f the different cases.

Case	Ratio of calculated to true reserves	Comments
0	**1.49**	Base case
1	**1.58**	**High** fracture permeability
2	**1.48**	**Low** fracture permeability
3	**2.05**	High effective matrix permeability
4	**1.31**	Low edective matrix permeability
5	**1.98**	High initial liquid saturation
6	2.15	**Low** initial liquid saturation
7	**1.48**	High C-factor
8	**1.57**	**Low** C-factor
9	0.48	Large fracture spacing
10	2.25	Small fracture spacing
11	1.29	40- to 20-acre
12	1.19	40- to 20- to 10-acre spacing
13	1.52	20-acre spacing
14	**1.56**	[illegible]
15	1.95	1% matrix porosity

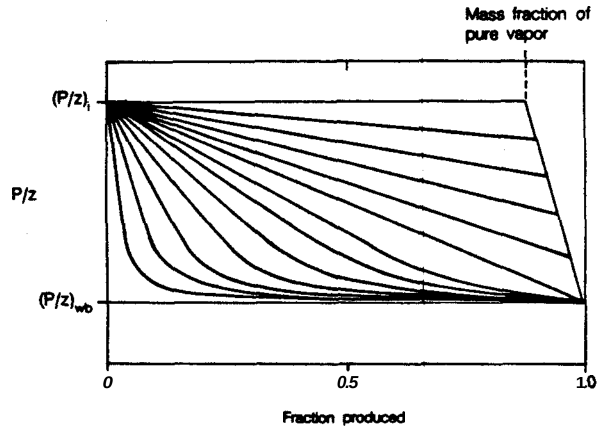


Figure 13: Theoretical curves of P/z vs. mass fraction produced for vapor dominated systems.

After having matched the flow rate decline for well GDC-65-12 over the eight-year period, it is of interest to investigate the variability in predicted flow decline for the different cases. Figure 16 shows the integrated results of projections over 30 years for the different cases. The variability is quite significant and the flow rate at the end of the thirty-year period varies by a factor of two (2-4 kg/s). **This** variability, of course, will have **an** important effect when the number of infill-wells needed is estimated.

CONCLUSIONS

The primary results of these studies of simplified vapor dominated systems are as follows:

1. The initial (or early) flow rate is primarily controlled by the near-well conditiods (C-factor) and fracture parameters (fracture permeability).
2. The long term flow decline is mostly controlled by: effective rock matrix permeability. fracture spacing (the flow decline is actually proportional to $(k_m)_{eff}/(FS)^2$, initial liquid saturation, and well spacing.
3. When the total cumulative flow is considered, it appears that the ultimate well depsity should not exceed that corresponding to 20-acre spacing. Additional in-fill drilling may only recover a small fraction of additional steam.

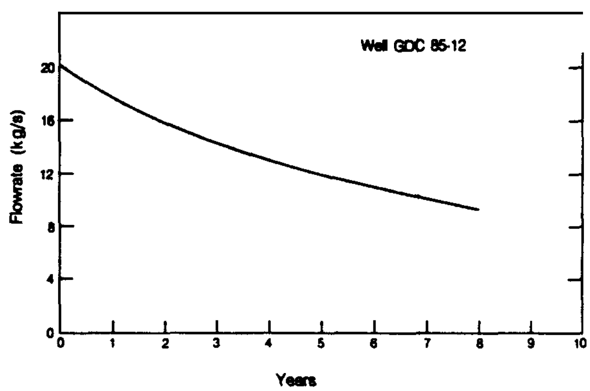


Figure 14: Flow rate decline of well GDC-85-12 at The Geysers.

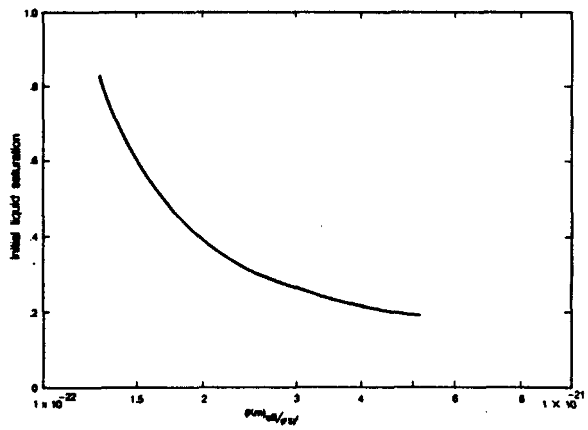


Figure 15: The relationship between initial liquid saturation and $(k_m)_{eff}/(FS)^2$ for cases which match the flow rate history of well CDC-85-12.

4. The plot of P/z versus cumulative production generally yields a straight line for fractured vapor-dominated reservoirs. However, extrapolation of the line for estimation of reserves can be in error because the physics controlling pressure decline in two-phase liquid-vapor systems is diderent from that of closed gas reservoirs.
5. When parameters considered applicable to The Geysers geothermal fleld are used, we find that reserve estimates using the P/z analysis method yield answers that are within a factor of two of the true value.
6. Modeling actual field data from The Geysers has illustrated the non-uniqueness of the results. The most sensitive parameters are the fluid recharge factor, $(k_m)_{eff}/(FS)^2$, and the initial liquid saturation. From these model results, it appears that for liquid saturations in excess of 50%, the fluid recharge factor can be determined reasonably accurately.

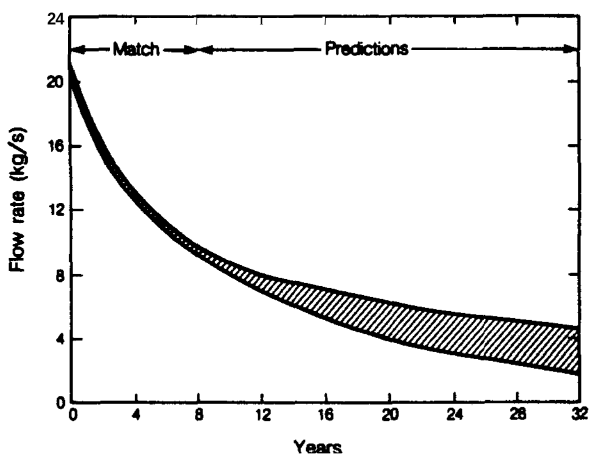


Figure 16: Future predictions for the flow rate decline of well GDC-85-12.

ACKNOWLEDGEMENTS

The authors express their gratitude to P. Fuller for his help in carrying out the numerical simulations.

This work was supported by the Assistant Secretary for Conservation and Renewable Energy, Office of Renewable Energy, Office of Renewable Technology, Division of Geothermal and Hydropower Technologies of the U.S. Department of Energy under Contract DE-AC03-76SF00098.

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