PROCEEDINGS, Sixteenth Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, January 23-25, 1991
SGP-TR-134

ANALYSIS OF REINJECTION STRATEGIES FOR THE GEYSERS

Mike Shook and D.D. Faulder

Idaho National Engineering Lab Idaho Falls, ID 83415-2107

ABSTRACT

The Geysers has undergone severe pressure decline in recent years, and reinjection of condensate is thought to be one key to sustaining current steam production. Other methods of pressure maintenance include load cycling, or reduction of steam production during off-peak hours. It is likely that a combination of these two will prove to be optimum in providing pressure and fluid maintenance.

This paper presents preliminary results of a study of various injection schemes for The Geysers. A number of injection scenarios are investigated, and an optimum scheme (based on specific parameters) is identified for two different quantities of reinjection.

INTRODUCTION

The Geysers is a mature geothermal field that has undergone severe pressure decline in recent years. Reinjection is thought to be one key to sustaining reservoir pressure and deliverability, but care must be taken in designing an injection scheme that avoids local quenching of the reservoir and/or premature breakthrough of the injectate. Given the current drought conditions in Northern California, water availability is another issue, and injectate must be used in as efficient a manner as possible. These concerns dictate the need for careful study of various injection strategies to identify the more efficient uses of injectate. Given the lack of regular well spacing and the number of wells present, it may not be possible to identify the optimum strategy; however, the less efficient schemes can certainly be identified.

The purpose of this paper is to compare reservoir response at The Geysers to a variety of injection schemes in order to identify the more efficient uses of available injectate. We have selected reservoir properties from the literature that are representative of The Geysers, and used actual surface well locations from an older section of the field. From a base case depletion scenario without reinjection, we then study the effect of reinjecting 30% of the produced mass (approximately the fraction currently reinjected). Different injection scenarios include using a single injector, and then using increasing numbers of injectors in order to find an optimum number. We then examine the effect of increased reinjection using our optimum case as a starting point.

Two points are worth noting at this stage. First, we are using 12 wells in this study, and to find a true optimum would require 12! simulations. We have elected instead to use engineering judgement to determine which wells to convert to injectors; therefore we hope to find what might be termed a "local" optimum. Also, this study addresses an optimum with respect to the technical side only; a later paper is planned that will discuss the relationship between the technical and economic optima.

The simulator used in this study is TETRAD, a fully implicit, multi-phase, multi-component, finite difference geothermal simulator. It has been

Work supported by the U.S. Department of Energy under
DOE Contract No. DE-AC07-76ID01570.

validated against a number of geothermal problem sets, and yields results comparable to those published elsewhere (e.g., Stanford Special Panel on Geothermal Model Inter-comparison Study, 1980).

MODEL DESCRIPTION

Petrophysical Data

The area used in this study encompasses a portion of The Geysers near Power Plants 3 and 4. This is an area of the field that has undergone some of the more severe pressure declines. The area used here is approximately 3000 feet by 1800 feet, and is 7000 feet thick. Of the more than 20 wells in this general area, 12 were included in our study. While we recognize the limitations associated with assuming a no-flow boundary in these simulations, additional wells exist just outside our study area. For the base case of no reinjection these "imaging" wells would tend to create a no-flow boundary, thus minimizing our error. The simulated field is shown in Figure 1.

The fractured nature of the field has been modelled using the Warren and Root dual porosity model (Warren and Root, 1963) with a shape factor as defined by Gillman and Kazemi (1983). Matrix block length (and thus fracture spacing) used is 150 ft., similar to that reported by Dykstra (1981). Williamson (1990) presented an algorithm for assigning porosities as a function of depth which was used in these simulations as well. Permeabilities used in this study compare favorably with those published elsewhere (Williamson, 1990; Bodvarsson, *et al.*, 1989).

In setting up this problem, we have neglected several physical phenomena; in particular, capillary imbibition, non-condensible gases, and geochemistry effects have been omitted. These can play an important role in reservoir studies, and should be examined in a future study.

Initial Conditions

The initial saturations used are consistent with a stable heat pipe in fractured porous media. Gas saturations in the fractures are in excess of 0.99, and the matrix gas saturation was 0.75. The matrix saturations are among the poorest-known data required for a simulation study, and can exert significant influence on reservoir response. A wide range of initial matrix gas saturations have been used in various studies, ranging from about 0.1 (Pruess, 1985) to 0.75 (Bodvarsson *et al.*, 1989). How this parameter affects our results will be addressed in a future analysis.

The initial pressure and temperature used in this study are 514.7 psia, and 470° F, corresponding to typical initial conditions at The Geysers. The datum was the top of the reservoir, with P and T increasing with depth according to vapor-static conditions. These initial conditions were used in a pre-exploitation simulation to ensure stability. Results indicated that these parameters constituted a stable initial condition.

Petrophysical properties and initial conditions are summarized in Table 1.

EXPLOITATION AND PRESSURE MAINTANANCE

Base Case

The base case of this study involves fluid depletion without any reinjection. Wells were produced on a bottom hole pressure constraint of 150 psig. After a short transient of rapid production decline, all 12 wells stabilized for several years, and then began an exponential decline of about 20%/yr. This decline rate is somewhat higher than other published estimations (Williamson, 1990; Barker *et al.*, 1989), perhaps due to differences in initial water saturations. Field-wide cumulative production histories are given in Figure 2. This figure shows that in the absence of fluid replacement, the reservoir is depleted in less than 15 years. In fact, at t = 4350 days (~ 12 years), over 95% of the mass initially present has been produced, and only about 4% of the energy recovered. This case shows the inefficiency of heat extraction through fluid depletion.

30% Reinjection

From the results of our base case, it is obvious that reinjection must be used in order to improve heat extraction. The following sections investigate the effect of a variety of reinjection schemes, where 30% of the produced fluid is reinjected. The injected fluid is assumed to be water at 150° F, and all injection and production is assumed to take place in the uppermost layer. Since we are faced with irregular well spacing, engineering judgement must be used in determining which wells should be converted to injection. The two primary rules of thumb used in selecting injectors were: 1) to separate injectors, and 2) to inject (where possible) nearer the middle of the field. In two cases, sensitivity runs were also made, changing which wells were converted to injection. In both cases, while individual well responses changed, changes in overall field response were minimal. Therefore, while we acknowledge sensitivity to different cases, we feel that these results are indicative of the effect of the different injection strategies.

The first case of reinjection involves 30% of field-wide production being reinjected into Well 11 (see Figure 1). Cumulative production histories for this case are given in Figures 3 and 4. For comparison purposes the base case results are also given in these figures. Because of the relatively small volume of fluid being reinjected this reinjection scenario does not accelerate production very much, but rather results in incremental recovery of both mass and energy. By reinjecting 30% of mass produced into one central well, energy recovery has increased by 35%, to a total of 5.4% of the energy in place.

It is interesting to note that by reinjecting only 30% of the produced mass, we are still operating in a depletion mode. In a gas field (and as the reservoir pressure is reduced through production this reservoir boils) virtually all mass in place can be recovered due to the high mobility of the fluid. Thus, every case studied here should result in the same amount of fluid recovered. Different injection schemes will increase or decrease the rate of recovery. Therefore, any differences in mass recovered in the following sections can be attributed to an extremely low (but nonzero) production rate when the simulation was terminated. In every case, however, over 95% of the theoretically-recoverable mass was recovered prior to termination of the run.

The second injection study distributes the injectate over 3 wells. We have selected Well 8, 23, and 16 as injectors, though several different configurations were examined. Wells nearest each injector were linked to provide the injectate. Cumulative recovery histories comparing the 1-injector and 3-injector cases are given in Figures 5 and 6. Although ultimate recovery for each case is virtually the same, increasing the number of injectors results in an acceleration in recovery of about 8 years. It is obvious that we are moving toward an optimum case.

Increasing the number of injectors to five (Wells 8, 14, 17, 19, and 20) yields an additional acceleration in energy recovery. Comparisons between the 3-injector vs. the 5-injector case can be made from Figures 7 and 8. The reduction of injectate on a "per-well" basis results in less local quenching of the reservoir. This in turn leads to improved areal pressure support, resulting in speedier recovery of energy. The increase in the number of injectors is this case results in another 5 year acceleration in recovery.

The final variation in this section is to convert 7 of the wells to injection. Wells 8, 9, 10, 11, 16, 17, 19, and 23 were converted for this run. Production histories for this case are given in Figures 9 and 10. Rate of recovery for this case is appreciably worse than in the five injector run. In fact, the rate of energy recovery in this run is very similar to that of the 3-injector case. The results of this run indicate that, while less injection per well can lead to less local quenching, spreading injectate over too large an area can result in insufficient pressure maintenance. On the basis of these results, it appears that injection through five wells effectively balances the negative effects of local quenching with improved areal pressure support.

This result should be qualified: *For the reservoir description used in this study, given the well spacing relative to the field boundaries and the amount of fluid reinjected, the optimum number of injection wells was found to be five.* These qualifications are important, since these studies were performed under a fixed and ideal set of conditions. Different reservoir descriptions or well spacings could easily lead to a different optimum. The more important result from this analysis is that a simulation study can be used in devising an optimum injection strategy.

Having arrived at an optimum injection strategy for the initial scenario of 30% reinjection, a question arises concerning what effect increased injection has on this optimum case. Analysis of the runs made in the previous section reveals that a small amount of quenching occurred around each injector. Obviously, increasing the amount of fluid reinjected can lead to increased quenching, an undesirable occurrence. Increased injectate also leads to improved heat extraction; we therefore need to study the effect increased injection has on a given injection strategy. While we recognize the difficulty in obtaining additional fluid for injection, this study evaluates the additional benefit of increased fluid availability. Two possible sources of additional injectate are through additional surface water acquisition and improved power plant design and operation.

60 % Reinjection

The first run in this study involves the same well configuration discussed above for the 5-injector case, the one difference being that 60% of the produced mass is reinjected. Steam and total mass production histories for this run are given in Figure 11. The difference between these curves is liquid production. As can be seen from this figure, the liquid phase cut during much of this run is in excess of 15%. This liquid production is due to excessive quenching, and represents a poor efficiency in injectate use.

In the previous study, we saw that increased number of injectors resulted in less local quenching, and so we increased the number of injectors to 7. The cumulative gas and total mass produced for this case is given in Figure 12. As in our 5-injector case, injecting 60% of the produced mass results in premature breakthrough of injectate, again resulting in a water cut of over 15%.

A third simulation was made in which three injectors were selected on the basis of their distance from other wells. In this way we hoped to reduce production of a liquid phase. Production histories for this case are given in Figure 13. In comparing the results from Figs. 11-13, one can readily see that, indeed, by injecting at a distance from production wells, one minimizes the production of liquid. This also results in a slight reduction in steam recovery; however, the reduction in water production probably offsets this. As we are still operating in a depletion mode, this results in a delay in production, not a loss. The delay in recovery is a direct result of the reduction in mobility of the fluid, as noted by Bodvarsson *et al.* (1985).

The energy recovery history for the most successful case above (3 injectors) is given in Figure 14. Also presented in this figure is the energy recovery from the optimum 30% reinjection case. Differences between these curves suggest several conclusions concerning our 60% reinjection case. First, it appears that reinjecting 60% of the produced mass results in appreciable quenching, independent of the pattern used. It does, however, appear that an increased distance between injection and production reduces the amount of liquid produced. Finally, reinjection on this scale results in a significant delay in heat extraction. It also results in a large increase in total heat extracted. When these simulations were terminated at 40 years, approximately 40% of the recoverable mass in still in the reservoir. This amount is on the order of mass initially in place; thus, energy extraction can be nearly doubled, albeit over an increased time period. Prudent reservoir management would dictate shutting in wells at large water cut, thereby increasing both the efficiency of the injectate and the length of the recovery period. However, the version of TETRAD used in this study does not support the option of shutting in geothermal wells as a function of liquid production fractions.

CONCLUSIONS

Based on the results of studies presented here, and limited to the same assumptions made here, we make the following conclusions:

1) An optimum number of injection wells can be determined for a given well pattern through simulation studies.

2) Given the irregular well spacing found in The Geysers, this optimum cannot be determined without careful examination of a variety of schemes.

3) The optimum configuration changes as the injection scenario changes, and therefore must be determined for each set of injection conditions.

4) Increasing the fraction of reinjected mass results in local quenching of the reservoir. Above some threshold fraction of reinjection, the fluid should be reinjected as far from production wells as possible. While this decreases the rate of steam recovery, it also reduces the amount of liquid produced.

5) While increasing the fraction of mass reinjected results in a delay in energy recovery, it also results in an increase of total energy recovered. The delay in steam recovery can probably be reduced through careful management of wells that show excessive water production.

ACNOWLEDGMENTS

We gratefully acknowledge useful discussions with Larry Murray of UNOCAL and Steve Enedy of NCPA, and thank the management of EG&G for permission to publish this work.

REFERENCES

Barker, B.J., M.S. Gulati, M.A. Bryan, and K.L. Riedel, "Geysers Reservoir Performance", *Trans.*, Geothermal Resources Council , **13**, October, 1989

Bodvarsson, G.S., K. Pruess, and M. O'Sullivan, "Injection and Energy Recovery in Fractured Geothermal Reservoirs", *Society of Petroleum Engin. J.*, August, 1985.

Bodvarsson, G.S., S. Gaulke, and M. Ripperda, "Some Consideration on Resource Evaluation of The Geysers", *Trans.*, Geothermal Resources Council , **13**, October, 1989

Dykstra, H., IV. Reservoir Assessment, in: *A Reservoir Assessment of The Geysers Geothermal Field*, Publication TR27, California Division of Oil and Gas, Sacramento, California, 1981.

Gilman, J.R., and H. Kazemi, "Improvements in Simulation of Naturally Fractured Reservoirs", *Society of Petroleum Engin. J.*, August, 1983.

Pruess, K., "A Quantitative Model of Vapor Dominated Geothermal Reservoirs as Heat Pipes in Fractured Porous Rock", *Trans.*, Geothermal Resources Council, **13**, August, 1985

Stanford Special Panel on Geothermal Model Intercomparison Study, *Proceedings*, 6th Workshop on Geothermal Reservoir Engineering, Stanford, Ca., Dec. 1980.

Warren, J.E., and P.J. Root, "The Behavior of Naturally Fractured Reservoirs", *Society of Petroleum Engin. J.*, Sept., 1963.

Williamson, K.H., Reservoir Simulation of The Geysers Geothermal Field", *Proceedings*, 15th Workshop on Geothermal Reservoir Engineering, Stanford, Ca., Jan. 1990.

Table 1: Petrophysical Properties and Initial Conditions

Petrophysical Properties	Matrix	Fractures
Porosity	$0.047 \geq \varphi \geq 0.03$	$0.02 \geq \varphi \geq 0.013$
	decreasing with depth	
Permeability (md)	0.01	20.
Relative Permeabilities		
Liquid	$k_{rl} = 1.33(S_l - 0.25)$	$k_{rl} = S_l$
Steam	$k_{rg} = S_g$	$k_{rg} = S_g$

Rock Heat Capacity = 0.238 BTU/lb_m
Rock Density = 165 lb_m/ft^3
Rock Thermal Conductivity = 40 BTU/lb_m·°F·D
Matrix Block Size = 150. ft.
Heat Flux = 0.158 BTU/hr.· ft^2 (500 mW/m^2)

Initial Conditions
Pressure = 500 psig
Temperature = 470° F
Datum: Top of reservoir
Mass Initially in Place = 2.01×10^{10} lb_m
Energy Initially in Place = 6.04×10^{14} BTU

Grid Data

Nx = 15	Δx = 198 ft.
Ny = 9	Δy = 194 ft.
Dx = 8	2250 ft $\geq \Delta x \geq$ 50 ft.

Figure 1: Schematic of Study Area Showing Well Locations
Wells located in center of blocks

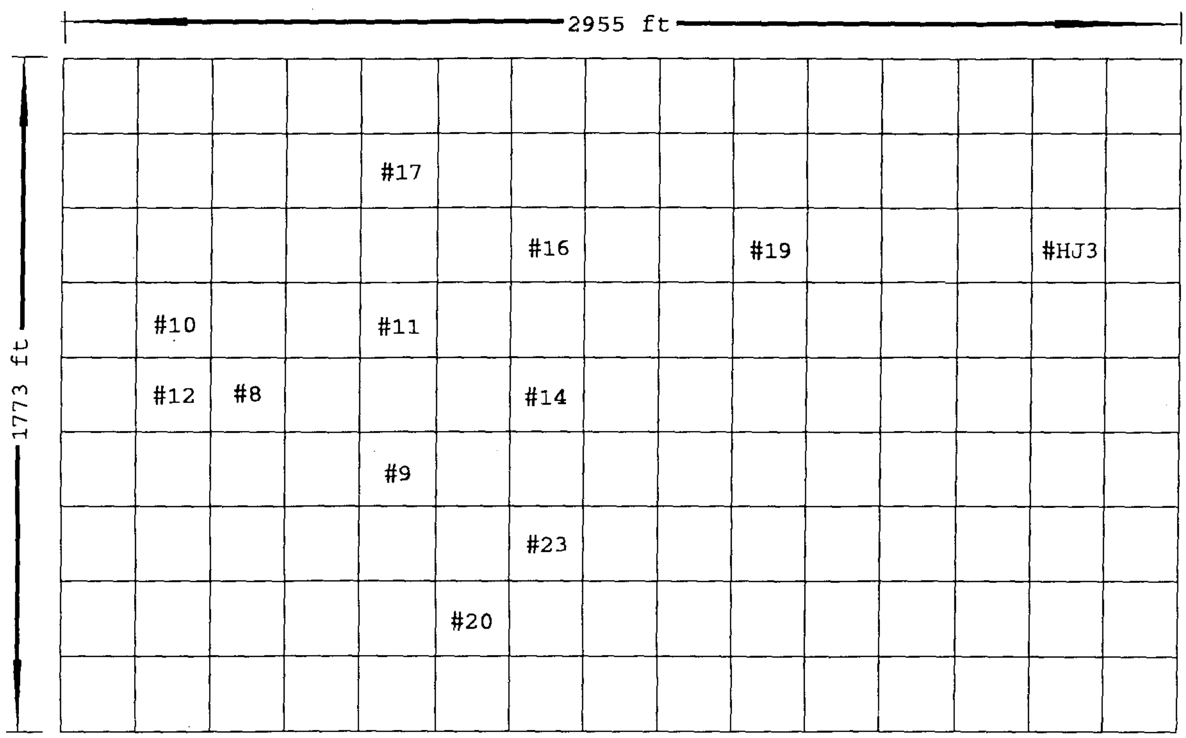

Figure 2: Cummulative Steam or Steam Energy Histories for Base Case – no Reinjection

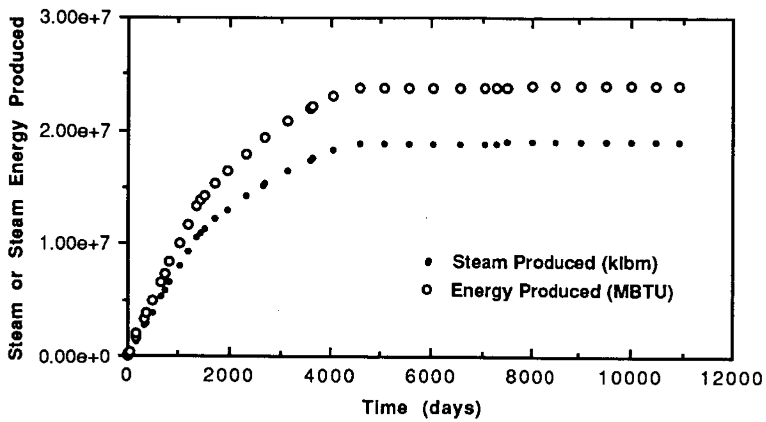

Figure 3: Comparison in Steam Production – No Reinjection vs. 1-Injector Case

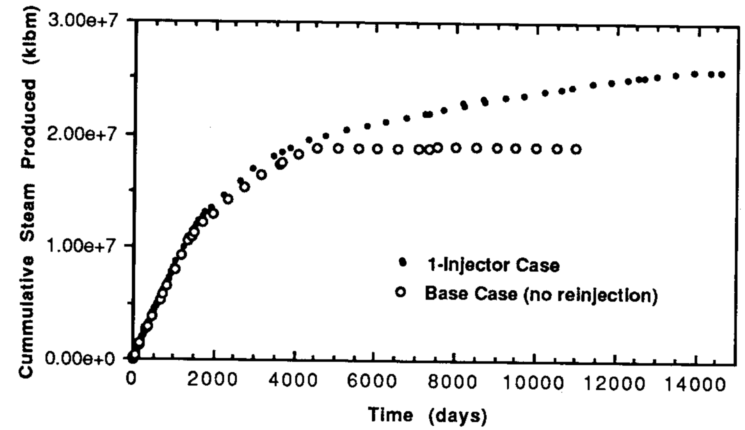

Figure 4: Comparison in Energy Recovery Histories – No Reinjection vs. 1-Injector Case

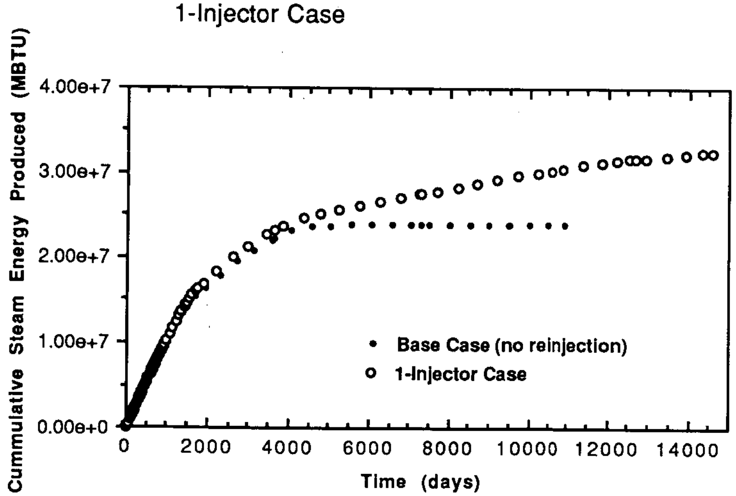

Figure 5: Comparison in Steam Production – 1-Injector vs. 3-Injectors

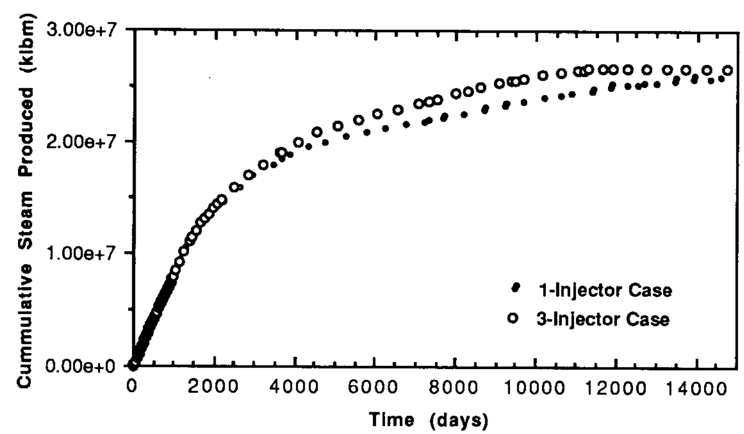

Figure 6: Comparison in Energy Recovery – 1-Injector vs. 3-Injectors

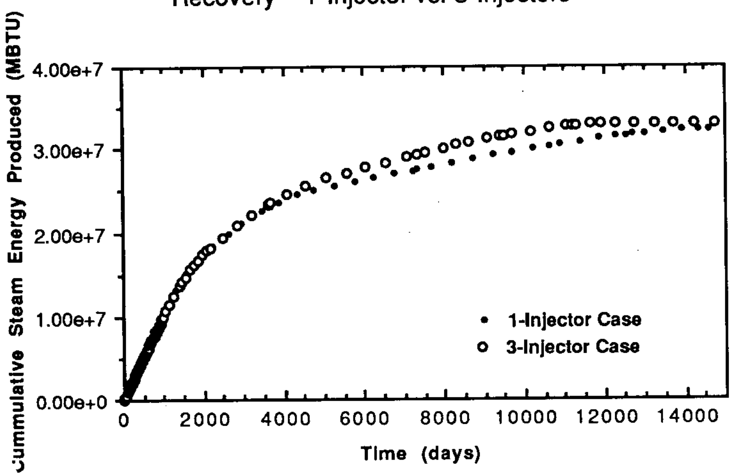

Figure 7: Comparison in Steam Production – 3-Injectors vs. 5-Injectors

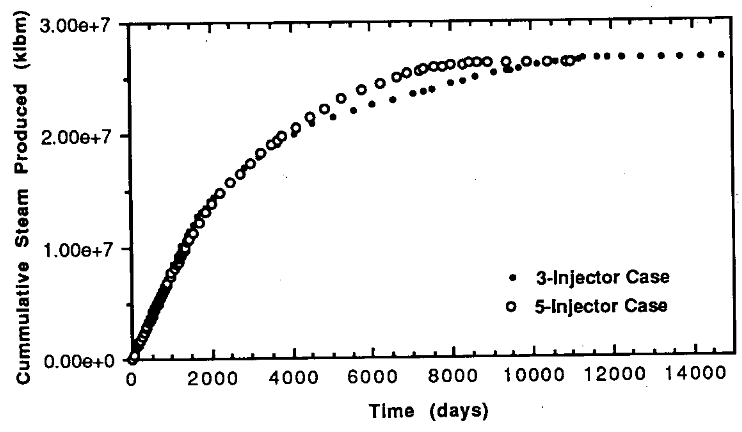

Figure 8: Comparison in Energy Recovery – 3-Injectors vs. 5-Injectors

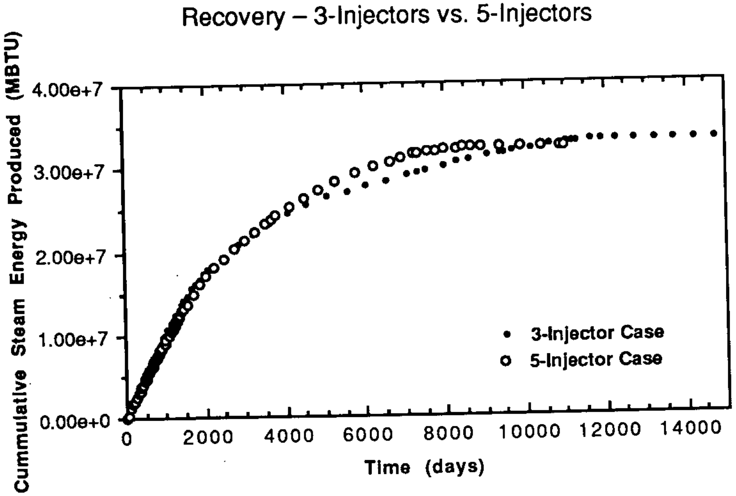

Figure 9: Comparison in Steam Production – 5-Injectors vs. 7-Injectors

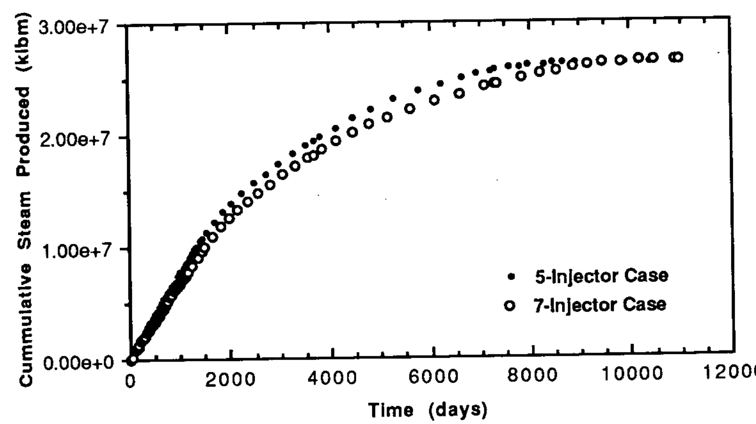

Figure 10: Comparison in Energy Recovery – 5-Injectors vs. 7-Injectors

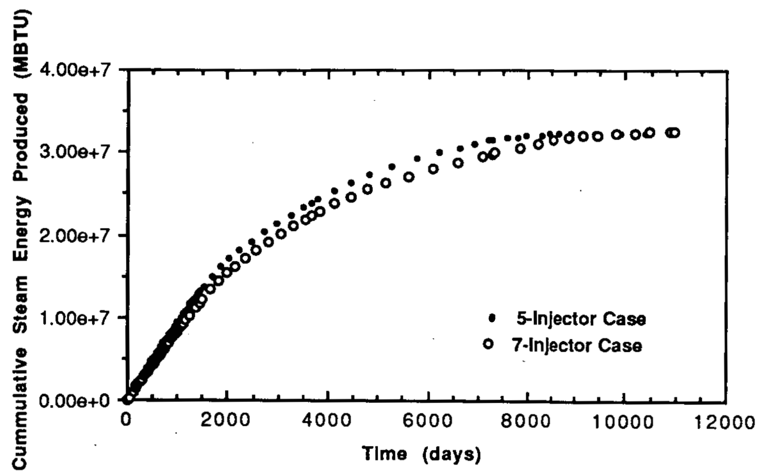

Figure 11: Cummulative Steam or Total Mass Production; 60% Reinjection, 5 Injectors

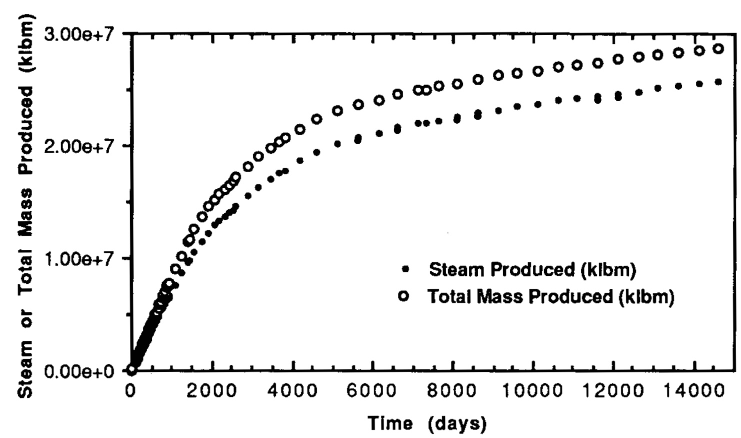

Figure 12: Cummulative Steam or Total Mass Production; 60% Reinjection, 7 Injectors

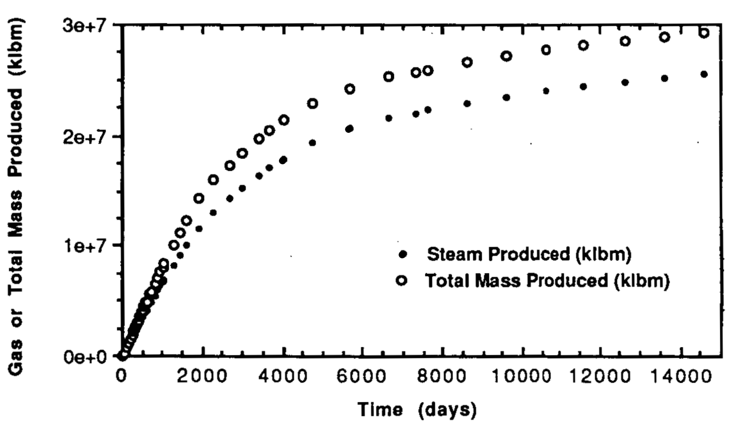

Figure 13: Cummulative Steam or Total Mass Production; 60% Reinjection, 3 Injectors

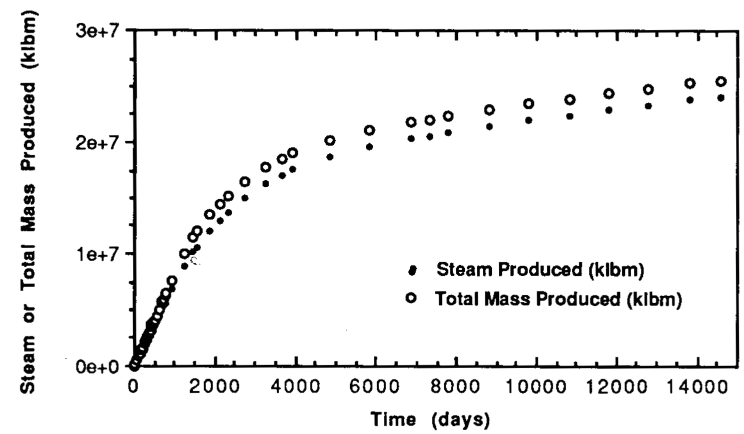

Figure 14: Comparison in Energy Recovery – 60% Reinjection, 3 Wells vs. 30% Reinjection, 5 Wells