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Numerical Studies of Cold Water Injection into Vapor-Dominated Geothermal Systems

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ABSTRACT

Recent reservoir pressure and steam flow rate declines at The Geysers geothermal field in California have attracted interest in studies of increased cold water injection into this system. In this paper, numerical studies of such injection into a fractured vapor-dominated reservoir are conducted using a two-dimensional radial, double-porosity model. The results obtained indicate that cold water injection into superheated (low-pressure) zones will greatly enhance the productivities of steam wells. Injection into two-phase zones with significant liquid reserves in the matrix blocks does not appear to aid in steam recovery until most of the original liquid reserves are depleted. Sensitivity studies are conducted over the range of fracture and matrix permeabilities applicable to the Geysers. The sensitivity of the grid size is also conducted, and shows very large grid effects. A fine vertical space discretization near the bottom of the reservoir is necessary to accurately predict the boiling of the injected water.

INTRODUCTION

The Geysers geothermal field in northern California has been under exploitation since the early 1960's[1]. The development of the field for electrical power generation progressed at an average rate of 67 MW/yr during the 1970's and accelerated to 150 MW/yr during most of the 1980's, reaching the current generating capacity of approximately 2,100 MW[2]. This rapid development has caused several problems including excessive reservoir pressure and resulting production decline, and high concentrations of noncondensible gases and chlorides in the steam produced in certain parts of the reservoir[3]. The pressure and well productivity decline is due to excessive steam withdrawal from the reservoir and can only be halted by reducing the net mass extraction from the system. Although the pressure has declined from 35 bars to below 14 bars since exploitation started, the temperature is still near the initial value of 240 °C; the reservoir longevity is limited by the original mass in-place rather than heat.

Under this circumstance, the problem of maintaining production and maximizing energy recovery from the resource becomes critical. Various remedies, including reduction of turbine inlet pressure, steam conservation in operations, and water injection, have been considered or adopted to reduce the rate of decline of steam production and extend the life of the field[2]. The results of analysis, along with field practice, show that reduction of turbine inlet pressure and steam conservation in operations are effective means to increase energy recovery and power production. Load-following has also been successfully used in some parts of the Geysers[4]. Experience with injection of cold water into vapor-dominated geothermal reservoirs such as Larderello, Italy[5] and The Geysers[4,6] indicates that an increase in production rates may result from the boiling of injected water in strongly depleted areas. However, in some cases the enthalpy of steam produced from wells near an injection well declines as a result of premature breakthrough of the injected water.

While much efforts have been made to study the impact

References and illustrations at the end of paper

of injection on reservoir performance and well productivity, it is still difficult to forecast the gain in production that might result from the boiling of injected water under field conditions. Numerical studies of the effects of cold water injection on production and reservoir performance of vapor-dominated systems have been performed by several workers including Schroeder et al.[7]; Calore et al.[8]; and Pruess et al.[9]. Schroeder et al. used a porous medium model and demonstrated the importance of gravity effects during injection into vapor-dominated systems. Calore et al. performed numerical studies of injection into superheated reservoirs and illustrated the boiling process associated with such injection as well as the effects of physical parameters on reservoir performance. More recently, Pruess et al. developed an analytical solution to study the boiling process resulting from cold water injection into superheated zones using a one-dimensional radial, infinite porous medium model, and showed that the boiling fraction of the injected water depends on the ratio of the injection rate to the permeability-thickness product. They also pointed out that vertical flow effects may be important in cold water injection into vapor-dominated reservoirs. There still remains much uncertainty about cold water injection at The Geysers, " as the thermodynamic effects of injection are not well known because most of the liquid moves under gravity towards the bottom of the reservoir below drilled depth " [10].

The purpose of the present study is threefold. First, the effects of water injection on production rates are investigated and the sensitivity of the results to reservoir properties as well as the rate of injection is addressed. Second, comparison studies of the effectiveness of injection into superheated zones and two-phase vapor dominated zones are performed. Third, grid effects on the simulation results are investigated, especially with regard to spatial discretizations in the vertical direction. Because three-dimensional field-scale models of The Geysers field have been and are being developed[10,11], it is important to investigate the grid block resolution required near the injectors.

THE GEYSERS FIELD

Over five hundred wells have been drilled at The Geysers, providing large amounts of data for characterization of this resource. This information includes lithologic logs, directional surveys, steam entry locations, static and flowing temperature and pressure surveys, production and injection histories, and geochemical data. These data have been collected by the field operators and most of the information is open file and available. Figure 1 shows a base map of the field and the approximate reservoir boundaries inferred from "dry" (non-production) wells. The productive area is elongated in the northwest-southeast direction extending for more than 20 km with an average width of about 3 km.

The Geysers field lies within Jurassic-Cretaceous Franciscan rocks arranged in a series of thrust fault-bounded slabs[12,13]. The main steam reservoir is located in graywacke horizons being deeper towards the northwest. A felsite basement is present throughout the field and its depth can be correlated to that of the main graywacke reservoir. At the end of 1987 about 8×10^{11} kg of steam had been produced from the resource with about 22 % of this mass injected[10].

Pressure transient (primarily pressure build-up) data suggest that the transmissivity of the fractured reservoir at The Geysers ranges from 1×10^{-11} to 1×10^{-10} m^3. Core data indicate that the average matrix porosity is in the range of 1 to 4 %[14]. Analysis of flow rate decline data, assuming that most of the reserves are located in the matrix blocks, yielded values for the so called recharge factor between 1 and 10^{15}. The recharge factor R is defined as[16]

$$R = C\frac{k_m}{D^2} \tag{1}$$

where k_m represents the matrix permeability, D is the average fracture spacing, and C is a constant with a value of 1×10^{22}. Steam entry data suggest a fracture spacing on the order of 100 m, yielding matrix permeability in the range of 1×10^{-17} to 1×10^{-18} m^2. These matrix permeability values are similar to those obtained from other geothermal fields such as Los Azufers, Mexico[17,18], and Nesjavellir, Iceland[19], and are consistent with results of large scale models of The Geysers[10,11].

APPROACH

A study of "cold water" injection into fractured vapor-dominated reservoirs, taking into account of the gravitational effects, is performed using a two-dimensional, cylindrical (ie., r-z coordinate) fractured-porous medium model. Figure 2 shows a schematic representation of physical problem considered in the study. The model has a radius of 1,500 m and a thickness of 2,500 m. The injection well is located at the center of the model and the production wells are assumed to be uniformly distributed in the region with radii extending from 500 to 700 m. The open intervals of the injection and production wells are assumed to be located in the top 1,000 m of the reservoir. This configuration is similar to actual field conditions at The Geysers, where single injectors are typically surrounded by a number of producers. The domain is divided into 24 grid blocks in the radial direction with two grid blocks used for the production wells. Because changes in the thermodynamic conditions near the injection well are expected to be large, a fine mesh is used with the first element having a radius of one meter. Within a radial distance of 100 m from

the injection well most of the elements are 10 m wide. The grid size is increased logarithmically from 100 to 500 m, and from 700 to 1,500 m. The 1,000 m thickness of the production zone is discretized vertically into two grid blocks, resulting in two and four grid blocks for injection and production wells, respectively. For the basic grid used in most of the study, the lower 1,500 m of the reservoir are subdivided into 9 layers using thicknesses of 4 x 300 m, 1 x 150 m, 2 x 50 m, and 2 x 25 m. This grid is determined to be sufficiently fine based upon a grid sensitivity study that will be described in a later section.

Because the coupled heat and mass transfer processes involved in the problem are too complex to be addressed analytically, the numerical code MULKOM developed by Pruess[20] is used in this study. Description of the code, its validation, and applications to various problems involving mass, heat and chemical transport in geologic media can be found in the literature[21]. Based on the available data, the permeability of the fractures may be two to three orders of magnitude higher than that of the rock matrix, so that the fractures may be considered as major conduits for transport of fluid and heat in the system, while the rock matrix acts as a source and sink for mass and energy. In the numerical simulations, we use the "Multiple Interacting Continua" method[22] for modeling the fractured characteristics of the reservoir, assuming three sets of orthogonal fractures. The fracture porosity and spacing assumed in the simulations are 1 %, and 100 m, respectively. Both the fracture and rock matrix are discretized into volume elements; fluid, heat, and chemical transport in the fracture network is represented by a two-dimensional r-z grid. To include the interactions between the fractures and rock matrix blocks, each fracture element is connected to a string of rock elements; in this study the rock matrix string contains three volume elements for each fracture element.

The parameters that are held constant in all of the simulations performed in the study are given in Table 1. Most of these parameter values are considered to be appropriate for conditions and practice at The Geysers. The injection enthalpy of 334,930 J/kg corresponds to a water temperature of 80 °C, which is reasonable given the fact that the injected water is a mixture of "hot" water from the condensers and "cold" surface water. The productivity index (PI) is defined from

$$q_t = \sum_{\beta = \text{liquid, steam}} \frac{k_{r\beta}}{\mu_\beta} \rho_\beta \, PI \, (P_\beta - P_{wb}) \qquad (2)$$

where q_t is the total flow rate, $k_{r\beta}$, ρ_β, μ_β, and P_β are the relative permeability, density, viscosity, and pressure for phase β, respectively, and P_{wb} is the assumed bottomhole pressure. The productivity index is generally unknown and is chosen so as to give a reasonable initial production rate for the assigned injection rate (25 to 50 kg/s).

Some of the injectors at The Geysers are located in reservoir zones which are strongly depleted and contain superheated steam (superheated zones). In other newly developed areas where cold water injection may be performed, the reservoir pressure is still reasonably high and both steam and liquid water are present (two-phase zones). Thus, the effects of cold water injection into both superheated and two-phase zones are investigated, as described below. It should be noted that in the simulations, we neglect effects of adsorption and capillarity, which are poorly understood for the system considered. Also we should note that although we have tried to design the problem for conditions at The Geysers, many of the important parameters are poorly known including the reservoir thickness and heterogeneity, permeability, and liquid saturation in the matrix blocks[11].

INJECTION INTO SUPERHEATED ZONES

In strongly depleted areas, the pressure and temperature at the top of the reservoir may be close to 20 bars and 240 °C, respectively, and the vertical pressure gradient is vaporstatic. This information, along with material property data, allows for approximate evaluation of the pressure and temperature distribution throughout the reservoir. Before starting the injection / production simulations, the system is run to steady state conditions by imposing a constant pressure and temperature of 20 bars and 240 °C, respectively, in the top elements, and a no flux boundary condition at the bottom of the reservoir. The resultant pressure and temperature distributions are then used as initial conditions for the exploitation simulations. Other boundary conditions considered in the simulations include a constant injection rate of 80 °C water and deliverability specified for the production wells (see Eq. 2). In order to investigate the effects of physical parameters such as reservoir properties and injection rate, five different cases are considered (see Table 2). For purposes of comparison, Case A which considers an injection rate of 25 kg/s and permeabilities of 1×10^{-13} and $1 \times 10^{-16} m^2$ for the fractures and rock matrix blocks, respectively, is considered to be the base case.

Base Case Results

The general behavior observed from the simulations is similar to that found using a porous medium model[8] and is as follows. When injection starts, the liquid plume migrates away from the injection well in both the horizontal and vertical directions. The horizontal and vertical movements are primarily controlled by the pressure gradient and gravity forces, respectively. The gravity forces are extremely strong for this

problem because of the large density difference between liquid water and steam at prevailing conditions. For instance, the ratio of the liquid water and steam densities under saturated conditions at 240 °C is approximately 50. During injection this enhances the downward movement of the plume and reduces the horizontal movement of the upper portion of the plume. With time the horizontal movement of the upper portion of the plume appears to terminate, and only downward movement of the plume in the vicinity of the injection well occurs. When the plume reaches the bottom of the reservoir, it continues to migrate radially outward along the bottom of the reservoir. The boiling process associated with the plume migration along the reservoir bottom is similar to that predicted in one-dimensional infinite systems[9]. The steam derived from boiling flows upward and laterally towards both the production wells and the outer surface of the shallow plume, where it condenses and releases the latent heat[8].

Figures 3 through 5 show some of the results for the base case (Case A). Figure 3 shows the phase distribution in the fractures after 5 years of simulation. At this stage, the lateral expansion of the upper portion of the plume has almost terminated. With the exception of the bottom layer, the injected liquid plume, in general, is confined to a region extending radially approximately 40 m from the injection well. The outer surface of the liquid plume is surrounded by a two-phase zone where the boiling of the injected water and the condensation of the flashed steam occurs. The two-phase zone extends further from the plume at greater depths, especially at the bottom layer. This shows that the movement of the injected water is downward, due to the strong gravity effects, and then laterally outward in the bottom layers, where most of the boiling of the liquid occurs. These large predicted vertical movements of the injected water are suggested by microearthquake studies at The Geysers[23,24]. The microearthquakes are found to concentrate around the injectors and often indicate a vertical liquid water movement to depths exceeding 3,000 m below the injection zone.

In the simulations, the injected water was tracked with a conservative tracer in order to investigate how much of the injected water boils and is produced as steam by the wells. It is assumed that the original reservoir fluid is pure water and that when the injected water with a certain concentration of the tracer boils, both liquid and the evolving steam contain the same tracer concentration. This allows to quantify the mass fraction of the fluid derived from the injected water for any grid blocks. The tracer concentration distribution in the fractures after five years is given in Figure 4, and shows that higher tracer concentrations (96 % by weight) occur at greater depths, resulting from the displacement of the native fluid by the injected fluid. At this time, a tracer concentration of approximately 70 % is observed in the production well area. Figure 5 shows the temperature distribution in the fractures after five years of simulation. Comparison with Figure 3 reveals that the 240 °C isotherm closely follows the locations of the outer surface of the plume, indicating that the temperature in the outer surface of the plume is relatively large compared to that of the liquid core of the plume.

Grid Effects

In general, grid effects on the results of numerical problems, resulting from the coarseness and the orientation of the grid relative to the flow field, may be large. In this study, the effects of the grid block size are investigated, especially the gridding in the vertical direction, as our studies indicate that the gridding in the horizontal direction is relatively unimportant compared to that in the vertical direction. In particular, we find that the grid used for the region near the reservoir bottom has a large impact on the simulation results. We have not investigated grid orientation effects for this problem, which may be significant.

The results of the numerical simulations show that the coarser grid the bottom layer, the slower the liquid plume moves away from the injection well. The reason for this artificial phenomenon is that in the numerical simulations, the heat contained in the elements of the coarse grid is higher than that in the fine one, resulting in a larger boiling fraction of the injected water, thus slowing down the movement of the liquid plume. To evaluate the grid effects on the simulation results, numerical experiments are conducted by systematically refining the grid size with all parameters remaining the same. Total of five different grid discretizations (ie., 7, 8, 9, 10, and 11 layers) in the vertical direction is considered in the study (Table 3).

Figure 6 shows the variation of the total steam production rate with time for different grids; all parameters correspond to the base case. The results show that for this problem, the production rates predicted for the cases with 7, 8, and 9 layers and grid spacing for the bottom layer ranging from 100 to 300 m, are very similar at all times. For these cases, the production rate stabilizes after five years as the boiling rate of the injected water is approximately equal to the total production rate. However, when the simulation domain in the vicinity of the reservoir bottom is discretized into a finer grid (ie., 10 and 11 layers) with grid spacing of 50 or 25 m for the bottom layer, after approximately 20 years of simulation the predicted production rate begins to deviate from those calculated for the cases with coarse grids. This is because for the fine grids, the bottom layer fills with single phase liquid, thus reducing the boiling fraction of the injected water. Figure 7 presents the cumulative production versus

time for cases with different grids, and shows a difference of approximately 20 % between the cases after 30 years of simulation.

To further test the grid effects, the injection rate is changed from 25 to 50 kg/s with other conditions remaining unchanged (ie., Case B; Table 2). Figure 8 shows the variations of the production rate with time for various discretizations of the reservoir thickness. It shows that the production rate predicted from the cases with 7 and 8 layers is very similar, and that the predicted rate tends to stabilize after two years of simulation. After an initial transient, the production rate derived for the cases with 9, 10, and 11 layers is nearly constant during the 2 to 15 year period, but declines rapidly in the next five years. Examination of the simulation results reveals that after 20 years of simulation the bottom layer is filled with the injected liquid for the 9, 10, and 11 layer cases, thus limiting the boiling fraction of the injected water and reducing the production rate. Figure 9 shows the cumulative production versus time. For the cases with coarse grids they are 70 % higher than those for the fine girds.

Sensitivity Studies

Sensitivity studies are performed to investigate the effects of reservoir properties and injection rate on the total productivity. Figure 10 shows the variation of the production rate with time for the various cases listed in Table 2. When no injection (Case C) is assumed, the production rate declines very rapidly and approaches zero after only 10 years of production. This rapid decline is caused by the low mass capacity of the system because only steam is present initially. In this case after about 10 years almost all of the initial reserves ($3x10^9$ kg) are produced (Figure 11).

In the case of 25 kg/s injection with the base case (Case A) parameters, the production rate gradually declines (Figure 10) and a total of $1.6x10^{10}$ kg of steam are produced during the 30 year period (Figure 11). This mass recovery is more than three times the initial reserves in-place, and approximately 60 % of the injected fluid is vaporized and produced by the wells. Using the base case parameters but doubling the injection rate (Case B), the total mass recovery is $2.7x10^{10}$ kg of steam, or nine times the initial reserves. In this case, about 50 % of the injected fluid vaporizes and is produced. Thus, injection into superheated zones significantly increases the reservoir productivity. This conclusion is also supported by data from field injection operations[6].

The sensitivity of the results on fracture and rock matrix permeability is also investigated. In Case D the matrix permeability is an order of magnitude lower than that in the base case ($1x10^{-16}$ m^2) and in Case E the fracture permeability is ten times lower that in the base case ($1x10^{-15}$ m^2). These ranges of values are comparable with those obtained from site-scale models[10,11] As shown in Figures 10 and 11, changes in these material properties have little effects on the steam production rate and the cumulative production. It is plausible that the matrix permeability will not greatly affect the results for superheated conditions, as the mass of fluid contained in the matrix blocks is small. The fracture permeabilities tested are apparently high enough to support the rather small steam flow through the system modeled.

INJECTION INTO TWO-PHASE ZONES

Cold liquid injection into two-phase vapor-dominated zones is being carried out in newly-developed areas of The Geysers, mostly in regions near the flanks of the field. The thermodynamic conditions of two-phase zones are believed to be maintained through counterflow of liquid and steam that is sustained by a vertical heat flux[25,26,27]. In order to obtain these thermodynamic conditions that will be used as initial conditions for the injection / production studies, it is easiest to perform a numerical simulation on a single column with only fracture elements. The boundary conditions used for this simulation include two-phase conditions in the deepest fracture elements and a heat loss of 0.5 W/m^2 in the uppermost fracture elements[10]; it results in a stable vapor-dominated heat pipe[28]. If needed the lower boundary conditions are adjusted until the desired conditions in the shallow reservoir are reached. We obtain a vapor-dominated heat pipe with a near-uniform liquid saturation of 5 % in the fractures, and a pressure and temperature of 33.4 bars and 240 °C in the uppermost fracture elements. These stable initial conditions are then prescribed for all of the fracture element columns, and the two-phase boundary conditions at the bottom are replaced with a constant (0.5 W/m^2) heat flux boundary condition. Finally, the rock matrix elements are added and given the same pressure and temperature as the adjacent fracture elements. In this study, we assume a uniform initial matrix liquid saturation of 25 %. We also conduct simulations with 50 % liquid saturations and the results are similar.

The same cases as in injection into the superheated zone are considered. In general, the predicted migration paths of the injected water are similar to those obtained in the superheated zone problem. Figure 12 shows the phase distribution for the base case (Case A) after five years of simulations. It shows the vertical extension of the plume downward from the injection zone and a lateral extension along the reservoir bottom. A two-phase zone of considerable thickness still exists in the fractures in the bottom 700 m of the system, whereas the fractures in the upper part have dried out due to

production. Examination of the simulation results at five years shows that high tracer concentrations are not found beyond the region of the liquid plume. This suggests that at this time the boiling fraction of the injected water is very small. Figure 13 shows the temperature distribution after five years. This figure indicates that the temperature at the reservoir top has decreased by a few degrees as a result of boiling of the native fluid. It is noted that after 15 to 20 years the boiling fraction of the injected water becomes more pronounced as the native fluid gets depleted.

Sensitivity studies of the effects of material properties and injection rate on long-term production behavior are considered. Figures 14 and 15 show the production rate and cumulative production versus time, respectively, for all of the cases considered. Note that because the same productivity index is used for the production wells as in the superheated zone studies, the predicted production rate is fairly high. These figures show that there appear to be no significant benefits derived from injection into two-phase zone in terms of the instantaneous and cumulative steam production. The reason for this is that for this system, the initial mass reserves, with 25 % liquid saturation in the matrix blocks, are large and can sustain steam production for an extended period of time. Most of the produced steam in the two-phase zone case is derived from boiling within the matrix blocks rather than from boiling of the injected liquid. In fact, the region invaded by the liquid plume is cooled down, and this hampers the production of the liquid reserves from in this region as no boiling can occur.

Comparison of Figures 14 and 15 with Figures 10 and 11 shows that the effects of the fracture and matrix permeability on the production rate and cumulative production are relatively large compared to those predicted for the superheated zone studies. The large apparent effects of the fracture permeability (Case E) on the production rate are partly due to the deliverability model used (see Eq. 2), but also because of a rapid decline of the reservoir pressure associated with the high production rate. The effects of the lower matrix permeability (Case D) are also significant, especially at early times. This is because during the first 15 to 20 years, almost all of the produced steam is derived from the boiling of the initial water reserves in the matrix blocks, and the rate of mass release from the matrix blocks to the fractures is slower for a lower matrix permeability. After 15 to 20 years of simulation, the matrix water starts to be depleted, resulting in a flow rate decline for all cases excluding Case E. After that, in all the cases the production rate stabilizes, because the injected water boils and is produced by the wells, and the system again does not strongly depend on the fracture and matrix permeability.

CONCLUSIONS

Numerical studies of cold water injection into superheated and two-phase reservoirs have been conducted. The problem design and parameter values used in the simulations are believed to reflect conditions at The Geysers geothermal field. The effects of cold water injection on productivities of steam wells are evaluated for both depleted (superheated) and newly developed two-phase vapor-dominated zones. Sensitivity studies are performed on the effects of the injection rate, fracture and matrix permeabilities, and size of the numerical grid. Based on this study the following conclusions are reached:

1. Water injection into superheated and two-phase fractured vapor-dominated systems leads to a predominant vertical downward movement of the injected plume, because of the density differences gravitational forces dominate. This conclusion is in agreement with previous work[8] and results of microearthquake studies[23]. When the plume reaches the reservoir bottom, it starts to migrate laterally along it.

2. Water injection into superheated zones may greatly enhance the productivities of steam production wells. Our studies suggest a many-fold increase in energy recovery. Approximately 50 to 60 % of the injected liquid boils and is extracted as steam in the production areas. These results agree with observed productivity increases in wells near injectors completed in low-pressure zones[4,15].

3. The results of sensitivity studies for injection into superheated zones suggest that the effectiveness of injection and total steam recovery is not very sensitive to fracture and matrix permeabilities for the range of values tested which are believed to be representative of The Geysers based on site-scale modeling results[10,11].

4. Cold water injection into two-phase vapor-dominated zones does not appear to significantly enhance the well productivities until a significant superheated zone has developed. Most of the early steam production is derived from boiling of water initially present in the matrix blocks so that the fracture and matrix permeability greatly affect the instantaneous and cumulative production in this type of zones.

5. Sensitivity studies of the effects of the grid size show a strong dependence on the vertical mesh discretization near the reservoir bottom. For our problem, the grid

block thickness near that bottom should not exceed 25 to 50 m, in order to accurately model the rate of boiling of the injected water.

6. Given the large sensitivity of the results to grid discretization and perhaps also to grid orientation, in site-scale modeling one must carefully design the grid around injectors. This certainly makes conventional, uniform finite-difference gridding impractical for modeling The Geysers as local grid refinements will be necessary.

NOMENCLATURE

D = fracture spacing, L

k_m = matrix permeability, L^2

$k_{r\beta}$ = relative permeability in phase β

P_{wb} = bottom hole pressure, F/L^2

P_β = pressure for phase β, F/L^2

R = recharge factor given in Eq. 1

S_{rw} = irreducible water saturation

S_{rg} = irreducible steam saturation

μ_β = viscosity in phase β, $F\text{-}T/L^2$

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Table 1: Parameters held constant in the simulations

Parameter	Value
Injection Enthalpy, J/kg	334,930
Bottom Hole Pressure, bars	10
Productivity Index, m^3	2.56 E-11
Rock Matrix Parameters :	
Density, kg/m^3	2,650
Specific Heat, J/kg °C	1,000
Heat Conductivity, W/m °C	3.2
Porosity	0.03
Relative Permeability :	Srw = 0.5
(Linear Function)	Srg = 0.05
Fracture Parameters :	
Effective Porosity	0.01
Fracture Spacing : m	100
Relative Permeability :	Srw = 0.05
(Linear Function)	Srg = 0.05

Table 2: Physical Parameters Used for the Various Cases

Parameter	Case A	Case B	Case C	Case D	Case E
Injection Rate, kg/s	25	50	0	25	25
Formation Parameters :					
Rock Matrix :					
Permeability, m^2	1.E-16	1.E-16	1.E-16	1.E-17	1.E-16
Fracture :					
Horizontal Permeability, m^2	1.E-13	1.E-13	1.E-13	1.E-13	1.E-14

Table 3: Vertical Grid Spacing in different simulations

Layer No.	7 Layers (m)	8 Layers (m)	9 Layers (m)	10 layers (m)	11 Layers (m)
1	500	500	500	500	500
2	500	500	500	500	500
3	300	300	300	300	300
4	300	300	300	300	300
5	300	300	300	300	300
6	300	200	200	200	300
7	300	200	200	200	150
8	-	200	100	100	50
9	-	-	100	50	50
10	-	-	-	50	25
11	-	-	-	-	25

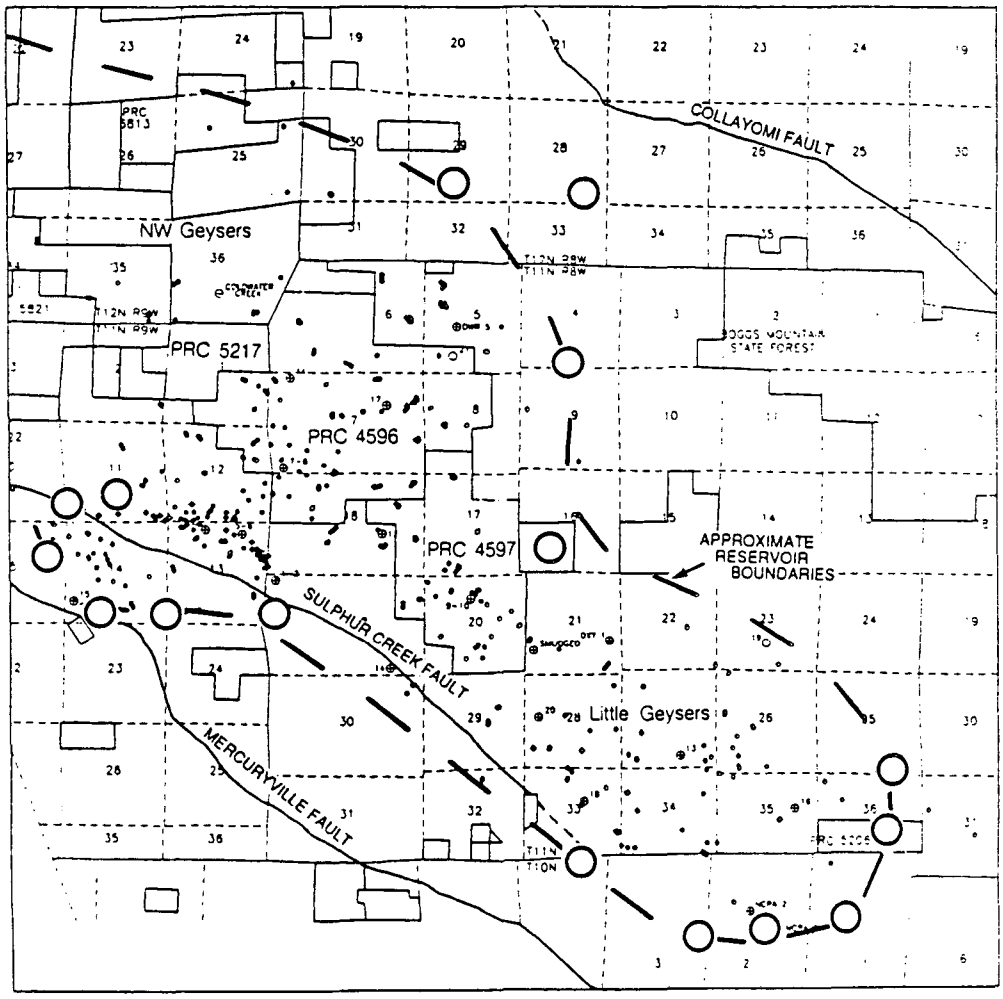

Figure 1 Open circles indicate the locations of dry wells close to assumed reservoir boundaries.

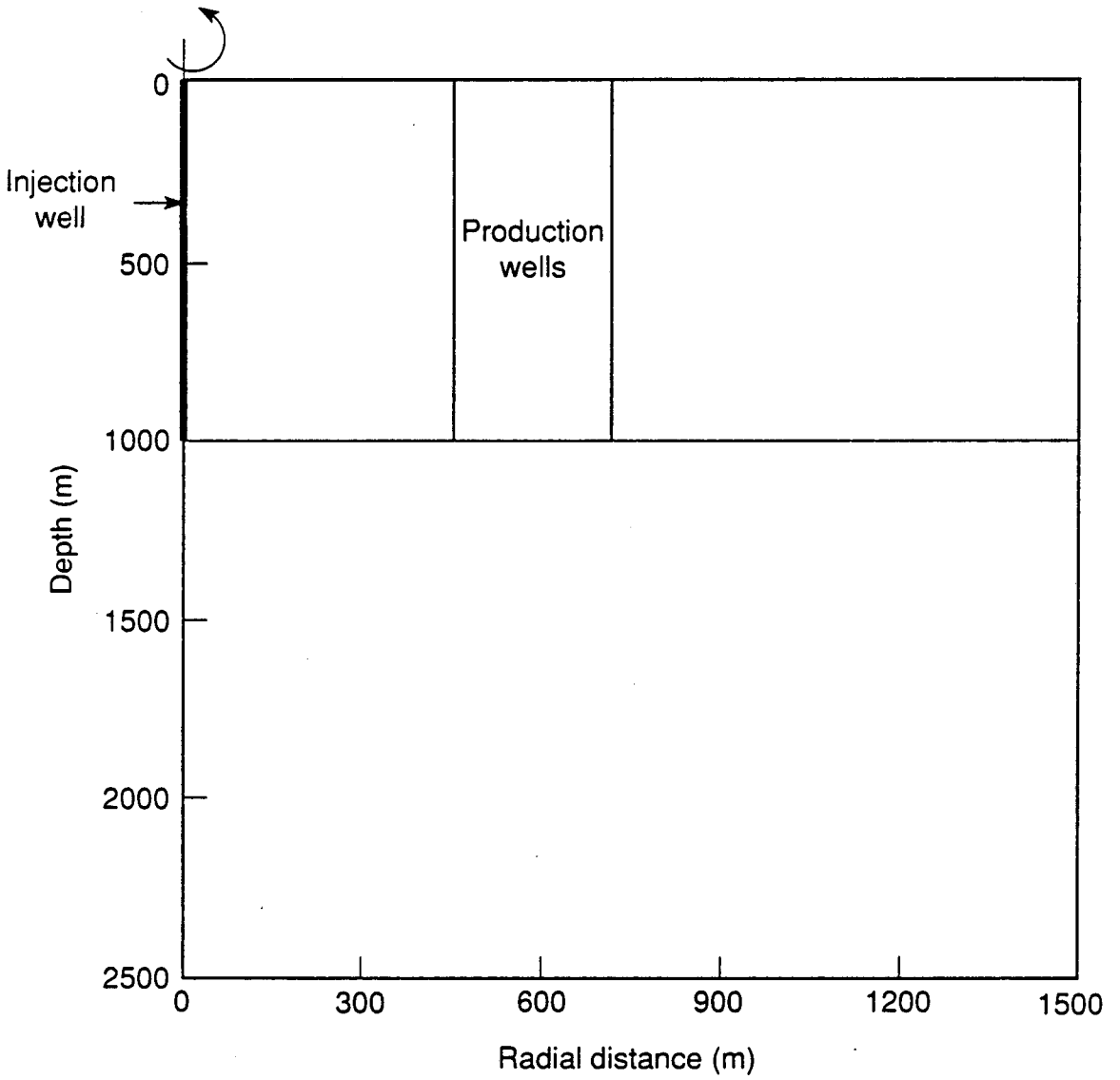

Figure 2 Schematic representation of physical problem.

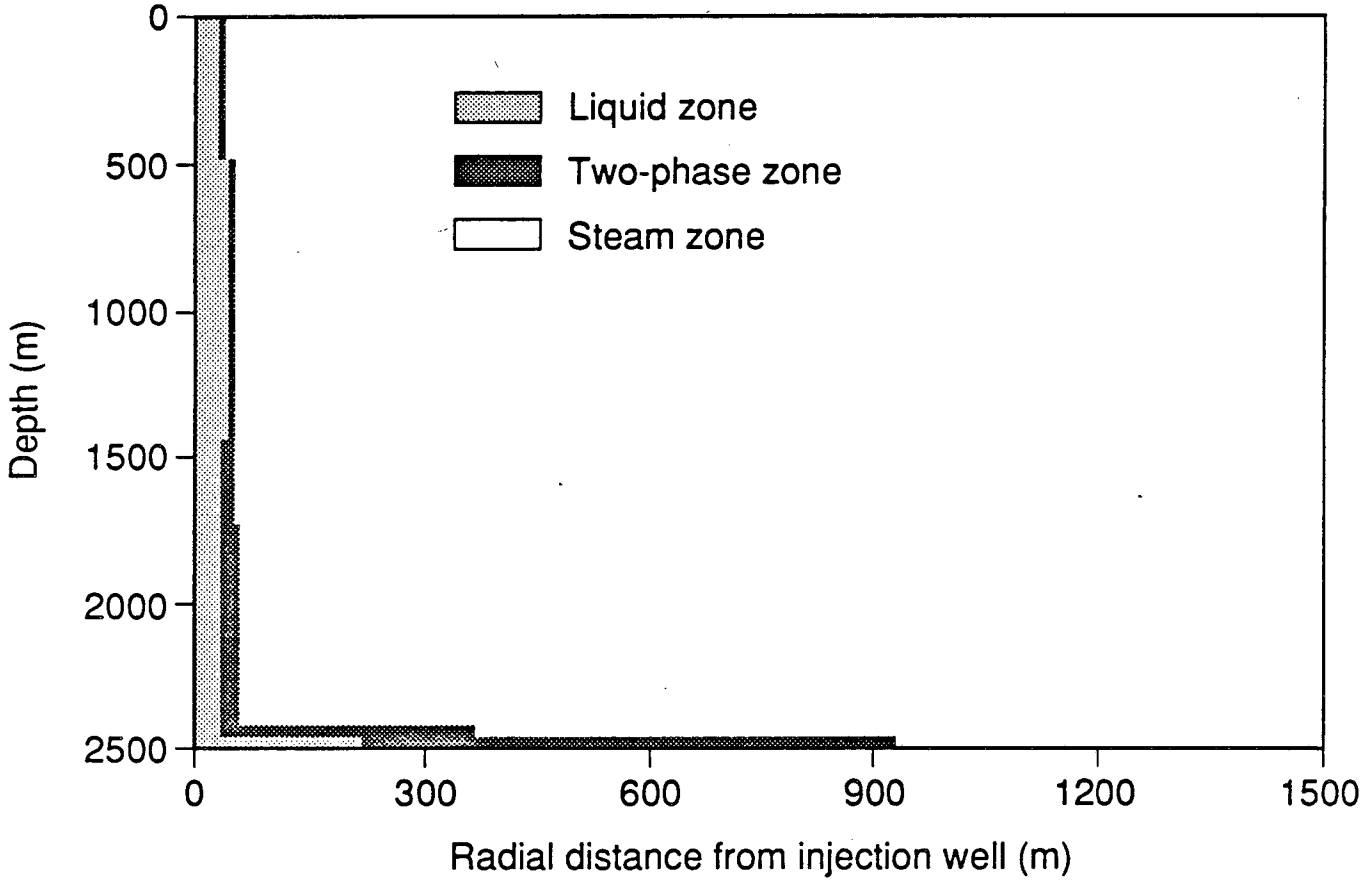

Figure 3 Case A (injection into superheated zones): Phase distribution in the fractures after 5 years of simulation.

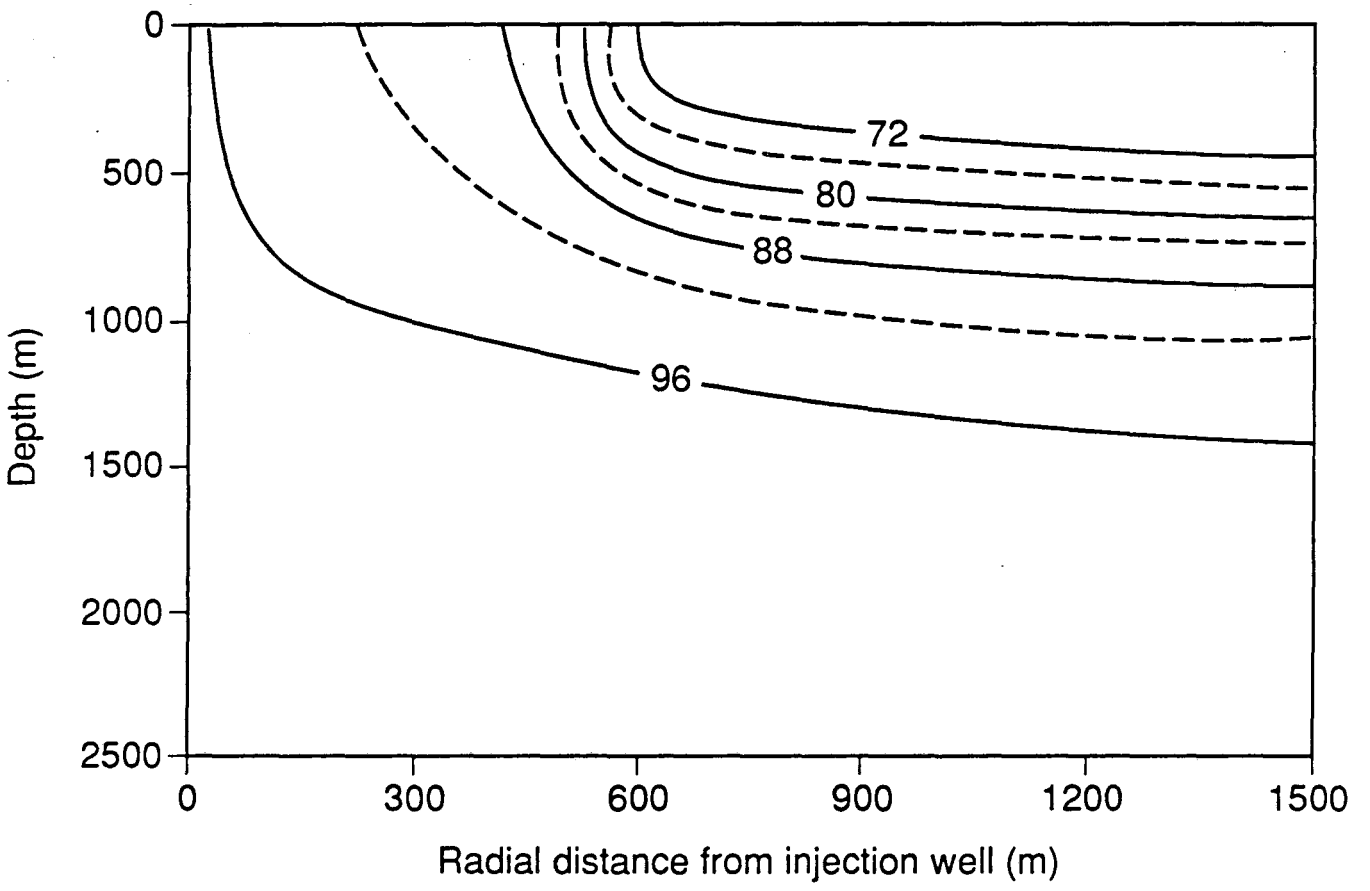

Figure 4 Case A (injection into superheated zones): Tracer concentration (wt %) distribution in the fractures after 5 years of simulation.

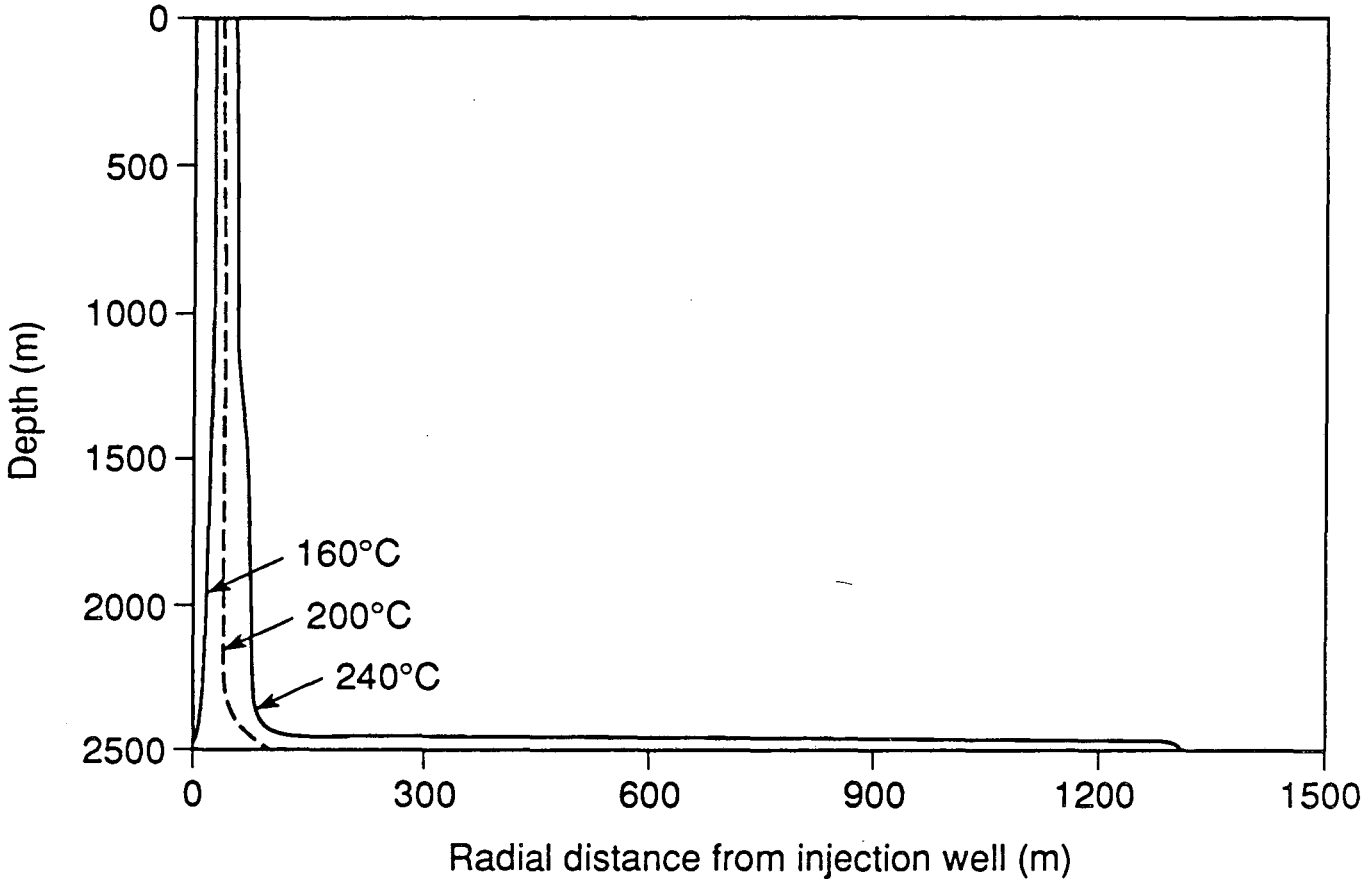

Figure 5 Case A (injection into superheated zones): Temperature distribution in the fractures after 5 years of simulation.

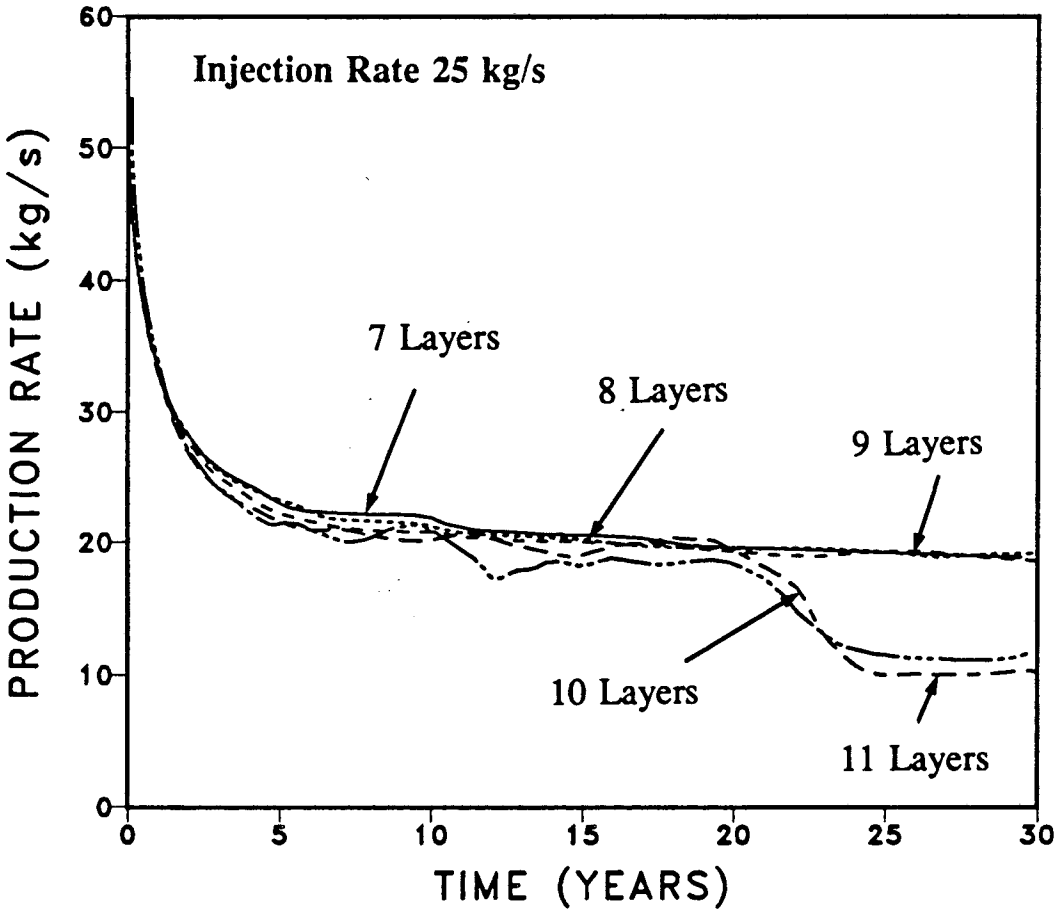

Figure 6 Case A (injection into superheated zones): Production rate versus time for various grid sizes.

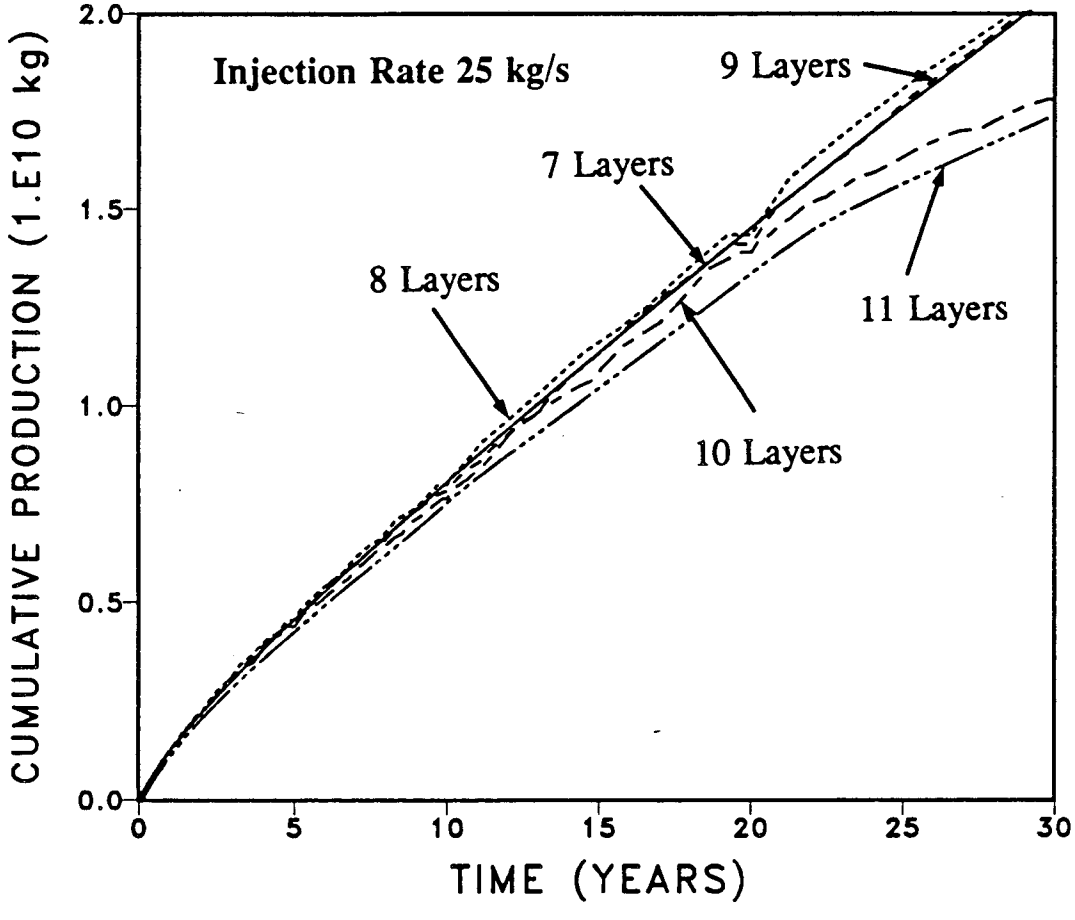

Figure 7 Case A (injection into superheated zones): Cumulative production versus time for various grid sizes.

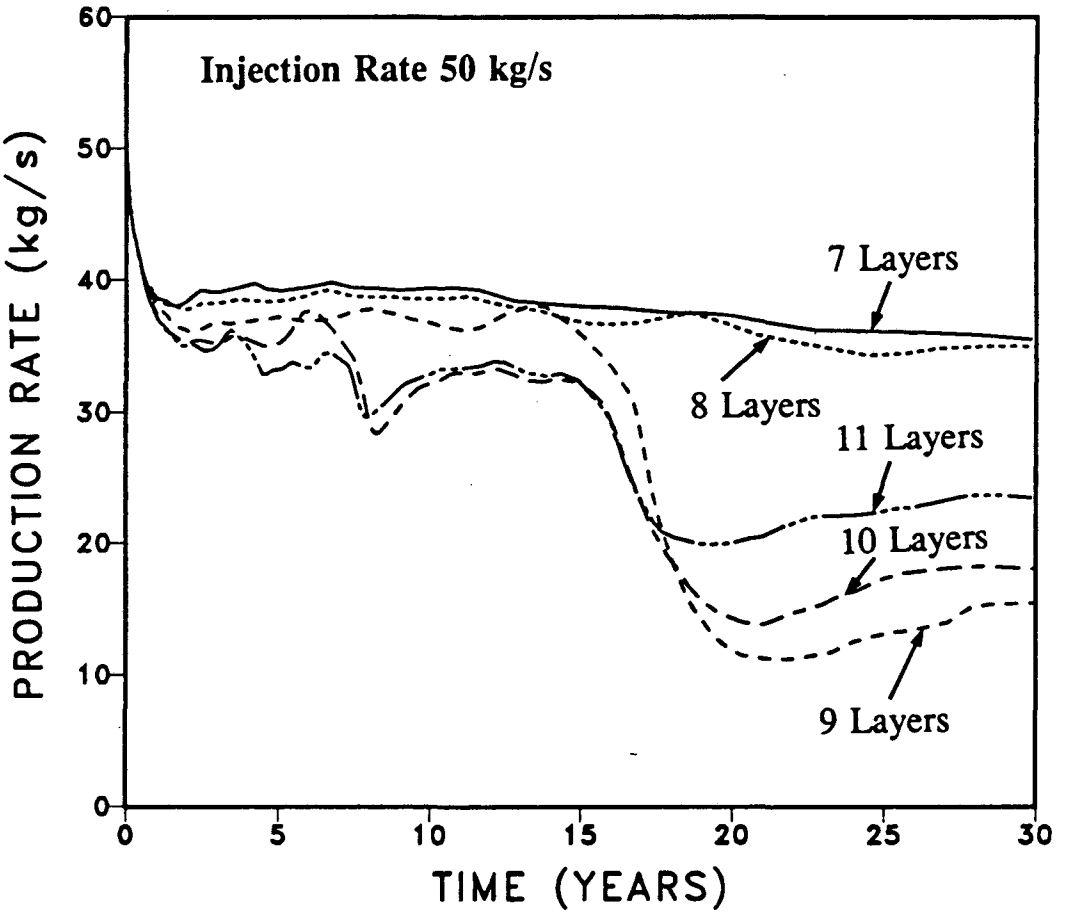

Figure 8 Case B (injection into superheated zones): Production rate versus time for various grid sizes.

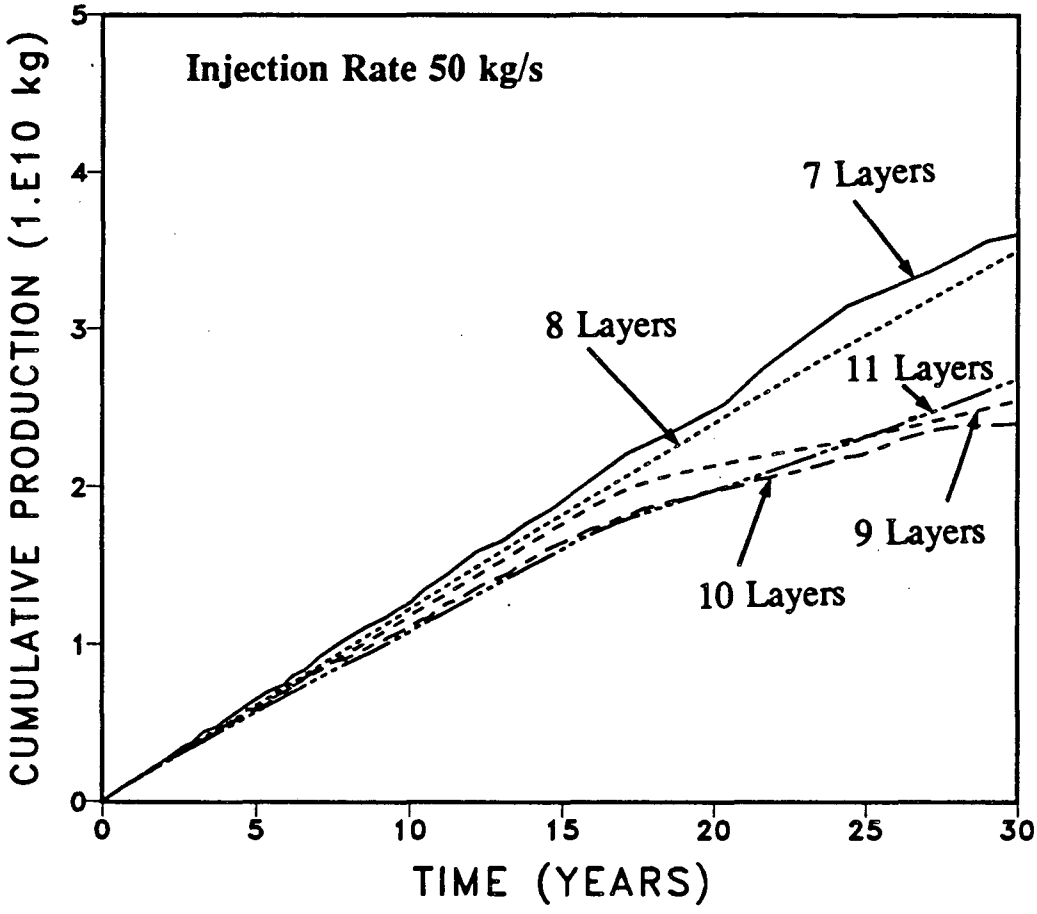

Figure 9 Case B (injection into superheated zones): Cumulative production versus time for various grid sizes.

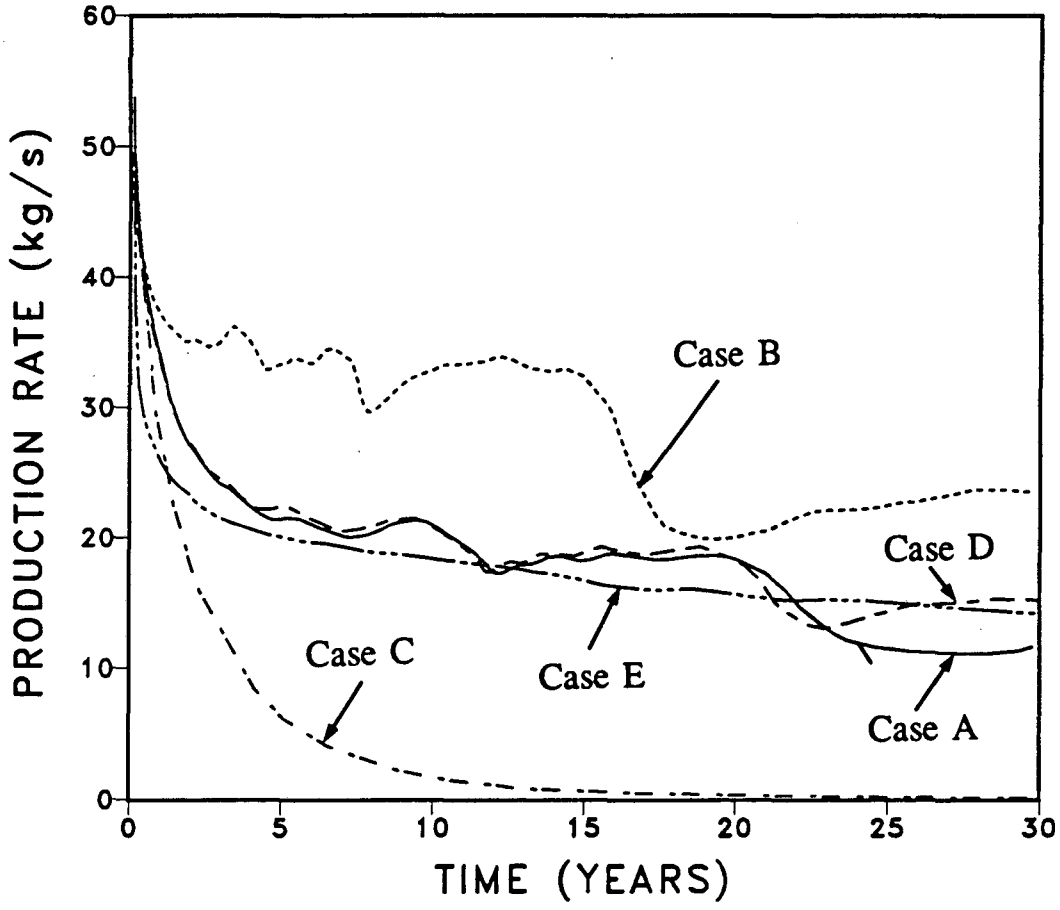

Figure 10 Cases A through E (injection into superheated zones): Production rate versus time.

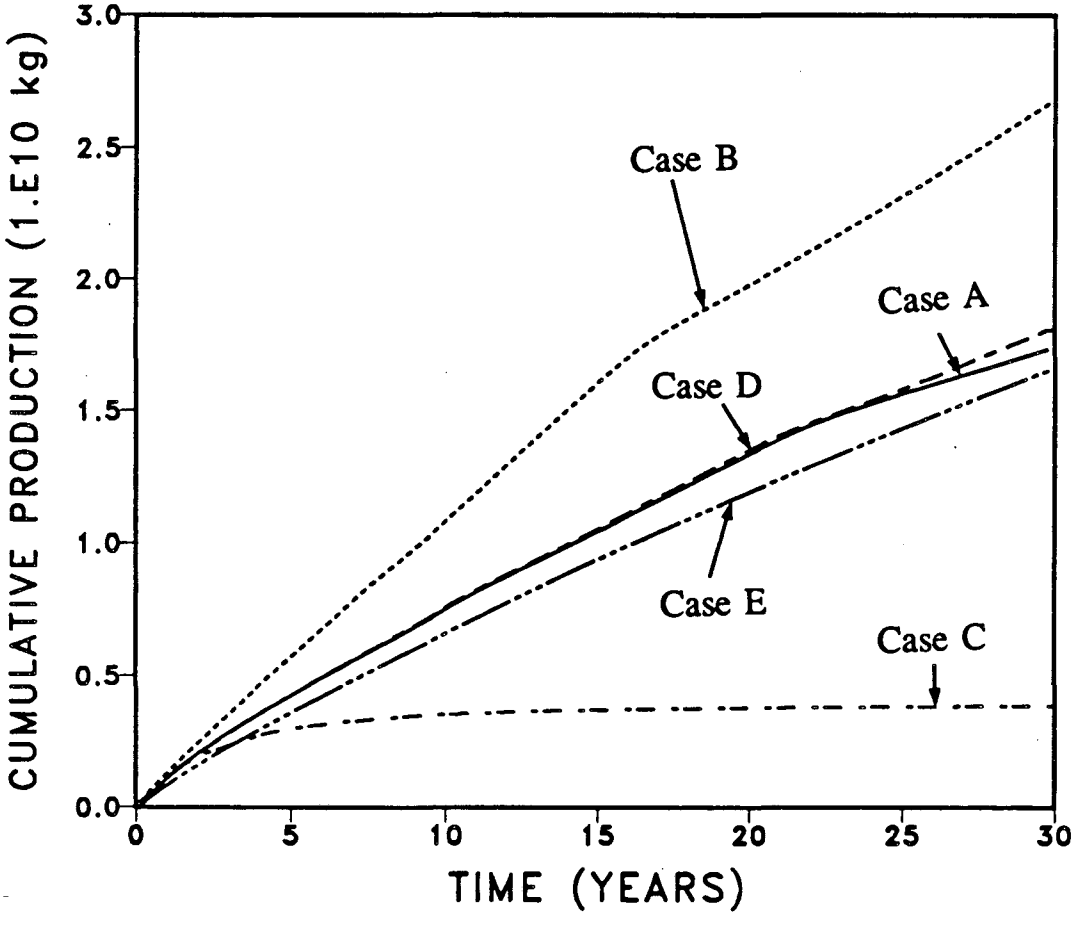

Figure 11 Cases A through E (injection into superheated zones): Cumulative production versus time.

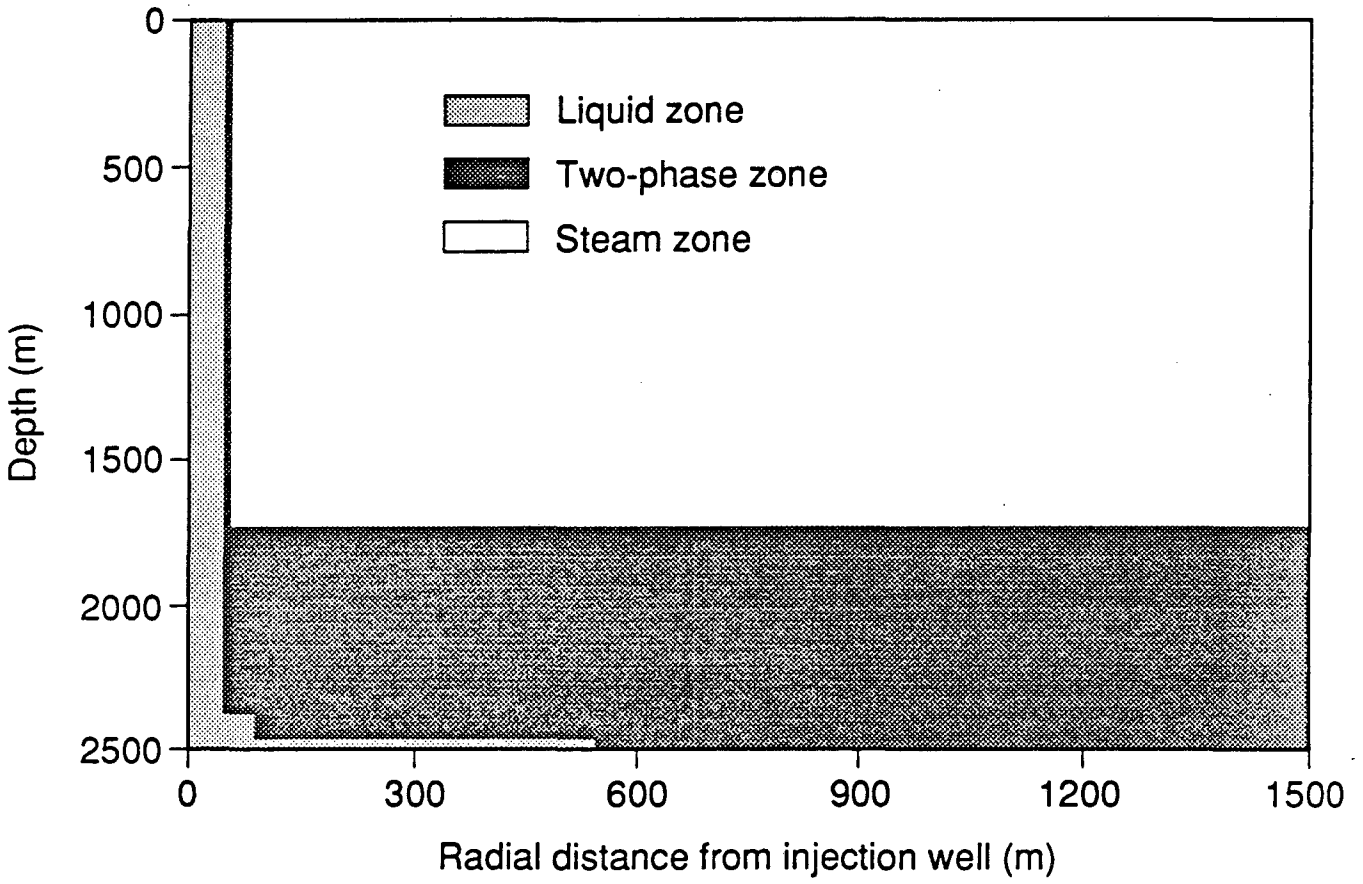

Figure 12 Case A (injection into two-phase zones): Phase distribution in the fractures after 5 years of simulation.

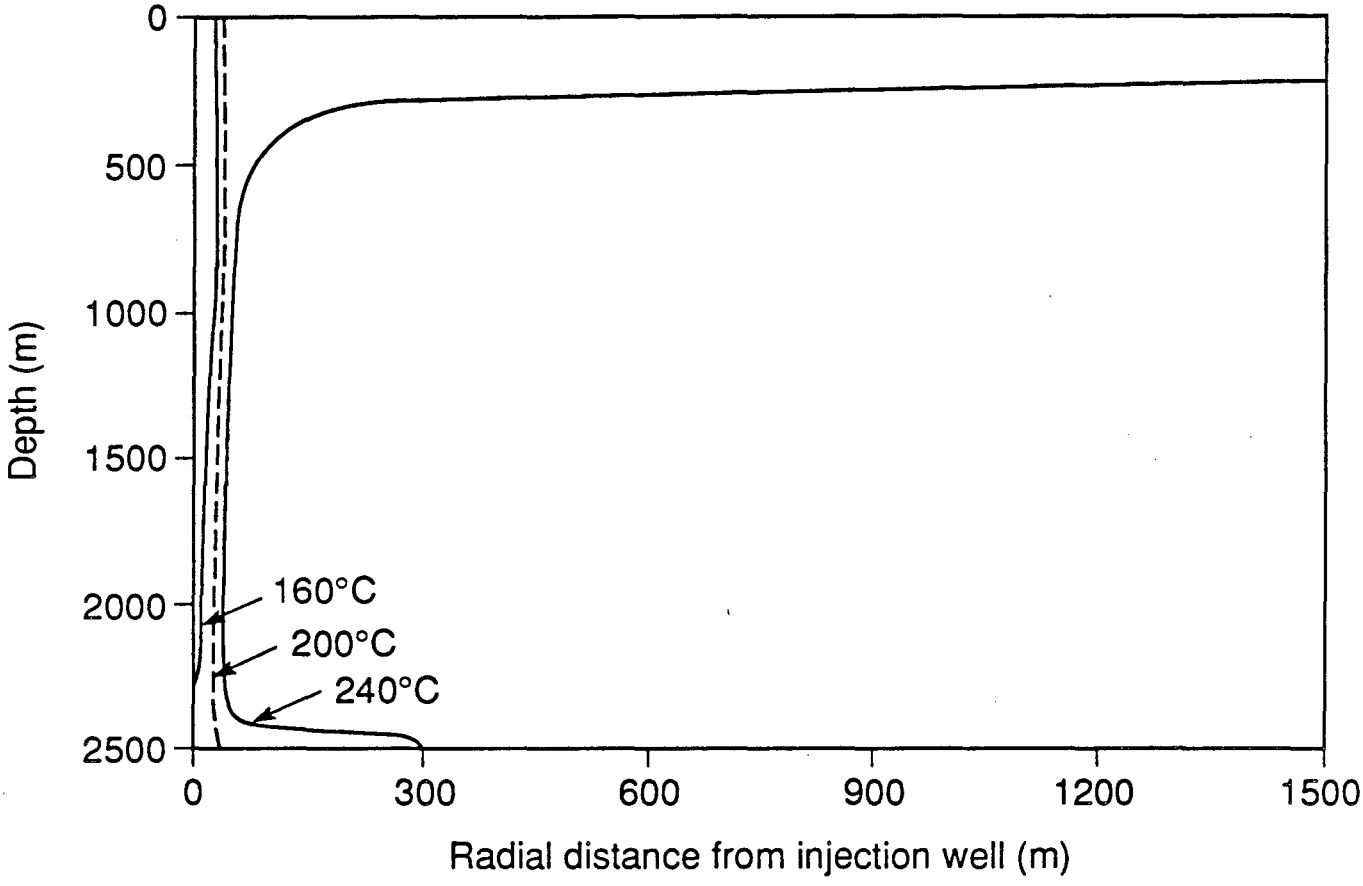

Figure 13 Case A (injection into two-phase zones): Temperature Distribution in the fractures after 5 years of simulation.

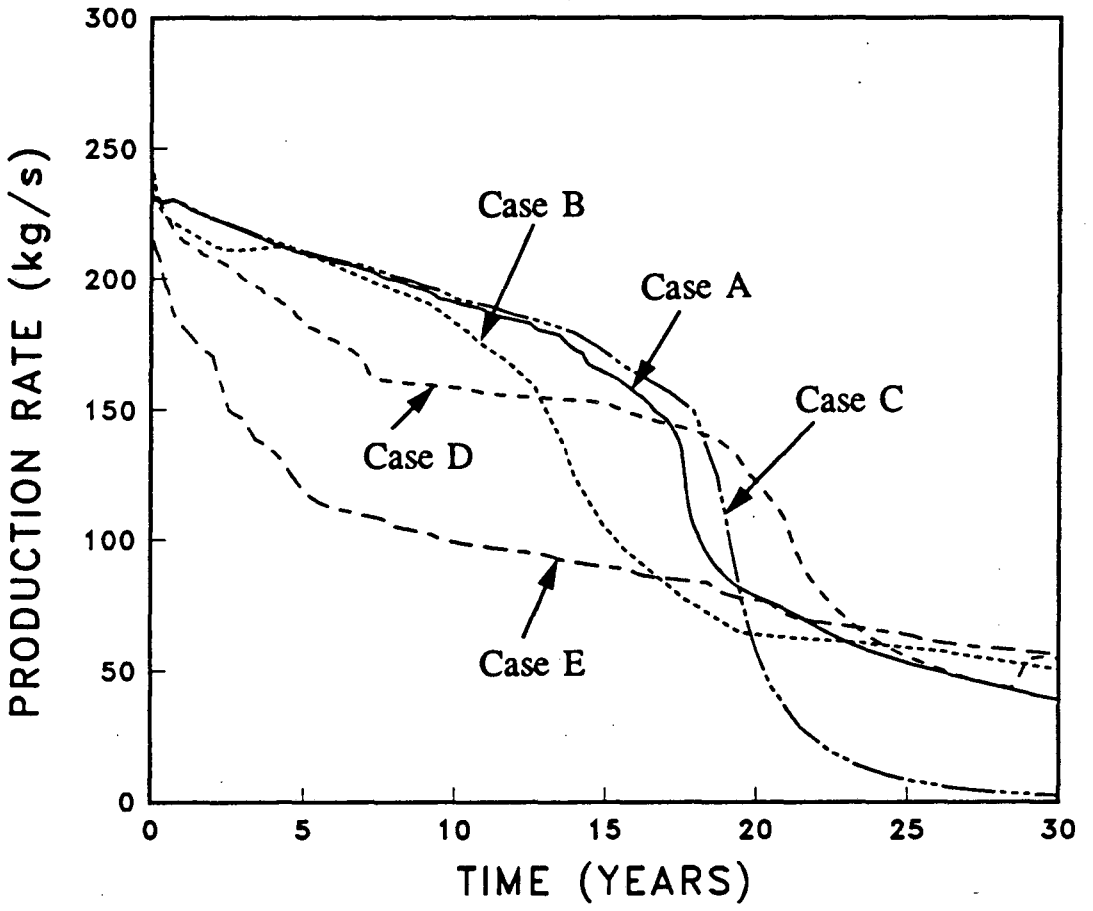

Figure 14 Case A through E (injection into two-phase zones): Production rate versus time.

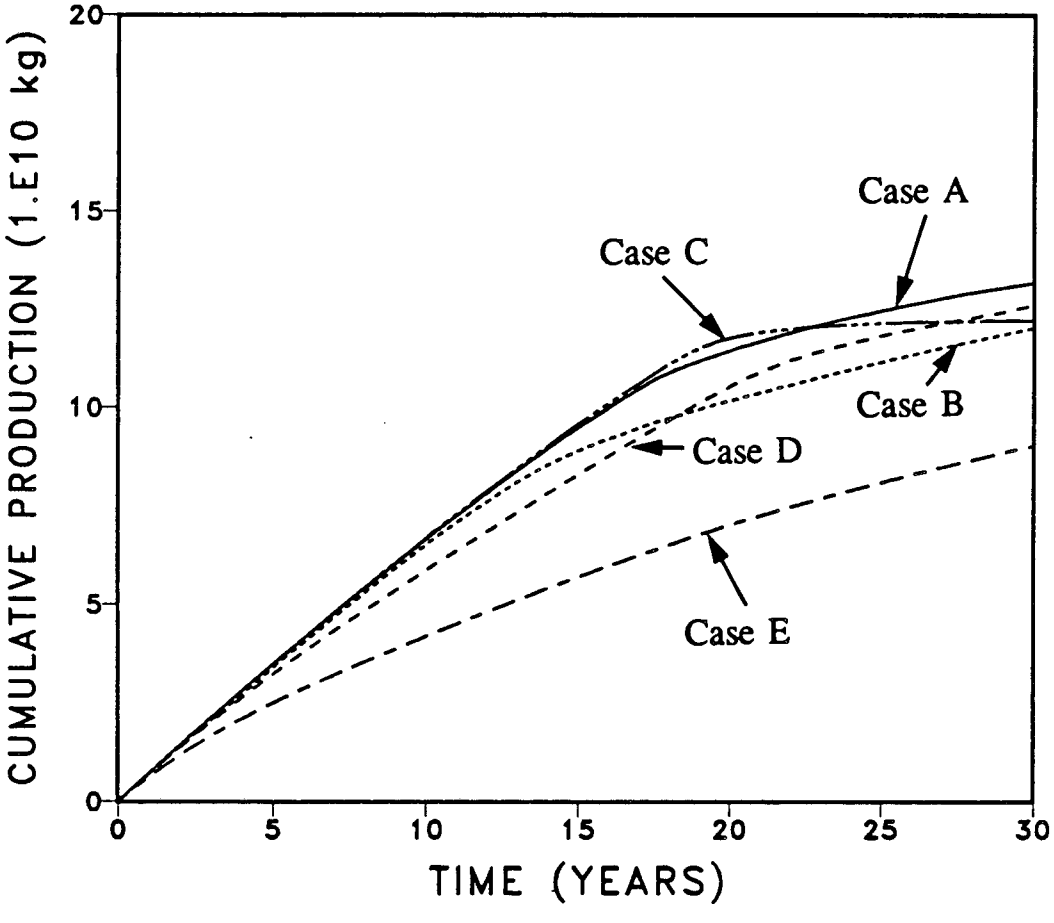

Figure 15 Cases A through E (injection into two-phase zones): Cumulative production versus time.

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