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EFFECTS OF INJECTION INTO THE HIGH-TEMPERATURE RESERVOIR OF THE NW GEYSERS - A CAUTIONARY TALE

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ABSTRACT

The energy contained in the high-temperature reservoir (HTR) of the NW part of The Geysers [Sonoma Co. Calif.) is large but underexploited due to high gas and corrosive chloride concentrations in produced steam. Although chloride can be mitigated, the gas contents exceed the rating of available power plants. As a result, most current exploitation of the HTR is limited to wells that produce steam from both the HTR and the overlying normal reservoir to form a mixture with a moderate gas content.

Injection of water into the HTR potentially could eliminate high gas in the steam as well as increasing production rates. These effects would result from dilution of gas by near gas-free evaporated injectate, and increase of pressure resulting from vaporization of injectate at high temperatures. We foresee only beneficial effects of injection into an isolated, unexploited HTR, but wish to caution that the effects of injection into an exploited HTR or into connected reservoirs may have some unfavorable aspects. The zone of increased pressure (produced by injection into a HTR) would extend more rapidly than the zone of reduced gas contents and, in an exploited reservoir with steam production from both the high-temperature and the normal reservoirs, the injection could temporarily raise the gas content in the mixed steam to unusable concentrations.

INTRODUCTION

The high-temperature reservoir (HTR) of the northwest Geysers was discovered in 1982 by the GEO Operator Co. and described by Walters et al. (1988). The HTR (to 346°C) was below a relatively thin, normal (250°C) vapor dominated reservoir (NVDR) containing both liquid and vapor. Temperature measurements and steam collections during drilling were made in order to locate the boundary between the reservoirs and to characterize the steam in each reservoir. In the well described, HTR steam was found to have much higher gas (to 10-12 wt% CO_2) than steam produced elsewhere in The Geysers, and the NVDR steam (above the HTR) contained 1.6 wt% gas (Figure 1). For NW Geysers wells producing only from the NVDR, total gas (NCG) ranged from 0.8 to 2.6 wt%, and Cl was <1 ppm; for wells producing from both reservoirs, NCG ranged from 2.6 to 7.7 wt%, and Cl ranged from 15 to 150 ppm. The temperature gradient between the high-temperature zone and the normal reservoir was steep, with a difference of up to 100°C occurring over a 100 to 200m depth interval. The pressures in the reservoirs were observed to be similar and there was no observed low permeability zone between them.

By the end of the 1980s GEO had developed the Coldwater Creek field using steam from wells that penetrated only the NVDR and wells that penetrated both the NVDR and the HTR (Figure 2). The chloride in the HTR steam was mitigated by treatment with NaOH solution and the power plant limitation of 2.5 wt% gas was met by mixing low- and high-gas steam. The areas of the Coldwater Creek field that produce from both reservoirs are shown by crosshatching in Figure 2. An adjacent part of the HTR was drilled but had to be abandoned because of higher gas. This steam could have been used if the power plant was equipped with high-capacity gas ejectors, but uncertainty involving possible future increase in gas contents and the high cost of gas handling equipment prevented development.

Planned transport of injection water from Lake County to The Geysers and successful injection tests in the southern Geysers with almost 100% returns have led to increased interest in injection into the HTR. This injection is expected to increase total steam by evaporation of injected water as heat is transferred from the hot rock of the HTR to the liquid. At the pressure and temperature of the HTR (about 35.9 bara and 347°C; Walters et al., 1988), vapor-filled rock with 10 % porosity and density of 2.5 g/cc contains 900 kJ/kg in rock and 4 kJ/kg in steam (data from Somerton, 1958). By injecting liquid until the temperature drops to 300°C, the mass of steam will increase by more than 35 times. This would produce an enormous increase in production and dilute gases by at least 35 to 1. In addition when injection establishes a liquid phase (at about 270°C), HCl in steam will transfer to the liquid and eventually be neutralized by reaction with rock..

In the long term there will be great benefits from the injection in the HTR; however in already-exploited parts of the HTR there may be a temporary unfortunate consequence. This could occur because wells that produce high-gas steam from the HTR depend on low-gas steam entering from the overlying NVDR to achieve acceptable gas concentrations for power generation. At the Coldwater Creek field (and elsewhere in the NW Geysers) most steam produced is a mixture of steam from wells that are completed entirely in the NVDR with low gas steam, and steam from wells that are completed in both NVDR and HTR with steam originating in both reservoirs. This steam mixture has a gas content depending on the relative flows of HTR steam with about 10 wt% gas and of NVDR steam with about I wt%.

The injection of water into the HTR will produce an initial pressure front that will move to the production well faster than the chemical (injectate) front. The amount that the pressure front will lead is dependent on the character of the fluid. In relatively incompressible liquid, the velocity of pressure change will be very rapid; in the two-phase water-steam of the NVDR, the velocity will be very slow; and in the compressible gas of the HTR (neglecting possible adsorbed or highly-saline liquid) the effect will be intermediate. In the HTR the velocity of the chemical front will be substantially slower than the velocity of the pressure front and the result, in wells producing from both the NVDR and the HTR, will be a relative increase of flow from the HTR. Because of the interconnection of the reservoirs there will be some increase from both reservoirs, but in the NVDR the increased pressure will be transmitted much more slowly. The increase of HTR-derived steam (relative to NVDR steam) will cause a transient flow of high-gas steam to the wellhead.

NUMERICAL MODEL

In order to illustrate the potential short-term concern regarding injection into the HTR, a two-dimensional, porous media numerical model was constructed (Figure 3a). No attempt was made in this preliminary study to construct a "Geysers analog"; rather, the model is intentionally simple. The domain is 2550 m wide and 1200 m thick (NX = 51, $\Delta x = 50$m; NZ = 24, $\Delta z = 50$m). A uniform permeability of 50 md, and porosity of 0.1 was used. Rock properties (specific heat, conductivity, etc.) were also assumed to be uniform, and are considered typical of geothermal systems (e.g., Williamson, 1990). Relative permeability functions used are simple exponential functions of saturation, and are given in Table 1. Capillary pressure was neglected in the present study. Reservoir and numerical properties are summarized in Table 1.

Several preliminary simulations were performed to determine a steady state initial condition. In order to develop a vapor-dominated heat pipe overlying a single phase, superheated zone, a mass-starved system was used as the starting point. Initial liquid saturations were set to 0.23, far below the residual saturation. Energy was added to the base of the grid at the rate of 0.5 W/m^2, and heat was lost to the caprock through conduction. Such a system has been shown (Pestov, 1995) to develop the required initial liquid saturation, pressure, and temperature distributions. For the initial liquid saturation noted above, 50% of the domain developed into a vapor-dominated heat pipe (White et al., 1971), with nearly constant pressure, temperature, and saturations. The balance of the model contained only single phase, superheated steam, with vapor-static pressure gradients and a relatively large (0.25°C/m) temperature gradient.

Using the steady state conditions developed as described above, the distribution of water and CO_2 was initialized. CO_2 content in the steam was set to 2 wt% in the NVDR and 10 wt% in the HTR. The initial conditions for this study are shown in Figure 3b.

No-flow boundary conditions were imposed on the model domain. Boundaries are sufficiently distant from the wells that they are not considered to be of particular importance; however, this will be further evaluated in additional modeling studies. A single injection well was placed at the centerline of the model, which injects only into the HTR. Two production wells were placed on either side of the injector at a distance of 650m. The first production well, P1, is completed over 8 layers, with *6* of them being in the HTR and 2 in the HTR; thus, 75% of the well's productivity is within the NVDR, and 25% in the HTR. The second well, P2, is completed deeper, with 50% of the completion intervals within the HTR. Well locations and completion intervals are also shown in Figure 3a.

Both production wells were placed on a pressure constraint. P1 was constrained to a downhole pressure of 1725 kPa (250 psi). P2 was constrained to 1750 kPa (255 psi), since it is completed 100m deeper. The production wells were allowed to flow for 3 months prior to the onset of injection. Various injection rates were considered, as discussed below. Injection temperature was assumed to be 35°C. Fluid is injected over four intervals 150-350 m deeper than the deepest production interval.

One of the purposes of this study was to determine the effect of injection rate on the dilution/displacement of CO_2. With the possible availability of additional water for HTR injection, three scenarios were simulated. The base case assumes a nominal 100% replacement (reinjection) of the initial production rate from both wells in the study area. The second and third cases consider 200% and 50% replacement, respectively. Total initial production rate is taken as 100 ton/hr, as is discussed below.

RESULTS

Base Case

Production rates for the base case are given in Figure 4. Aside from a relatively short transient, both production wells begin to decline prior to injection. With the onset of injection, each well shows a modest increase (about 0.6 tons/hr) in its rate. A substantial portion of this increase, however, is production of CO_2, as seen in Figure 5. Boiling (and subsequent volume change) has created a pressure wave in front of the injectate (the chemical wave). This wave displaces C02 and develops a bank of gas ahead of the injectate. Pressure and C02 mass fraction profiles are given at t = 0.375 yrs (approximately **45** days after onset of injection) in Figures **6** and 7. This time was selected because it is the approximate arrival time of the pressure wave at the production wells. Several features on these figures are noteworthy. One can easily see the C02 bank being driven towards the producers. This bank of NCG is nearly radial in shape, and therefore high-gas-content steam is also driven upward, into the NVDR. The CO_2 that remains in the HTR results in the first peak in CO_2 production shown in Figure 5; i.e., the first peak in C02 production represents the fastest streamlines between the injector and producers. C02 that is displaced into the NVDR subsequently moves horizontally into the production wells, and represents slower streamlines. This "secondary" C02 source is what causes the second peak in gas production shown in Figure 5. This also explains the differences in CO_2 production between the two wells. Well P1 (which produces mostly from the NVDR) has a lower initial peak C02 concentration (less production from the HTR) and a larger secondary peak concentration, whereas well P2 is opposite. **As** will be discussed later, this effect is also sensitive to injection rate.

A second set of pressure and C02 profiles for the base case are given in Figures **8** and **9.** These profiles are shown at t = 0.546 years, at about the time the chemical front has arrived at the producers. NCG mass fraction in the produced fluid is falling monotonically in response to increased injection-derived steam production. These figures also show the path-dependant nature of the displacement process: in the HTR, C02 has been nearly completely replaced with injected fluid, and the concentrations at the producers are relatively low. However, in the NVDR, C02 concentrations remain large. That C02 was displaced from the HTR, and is being transported relatively slowly towards the production wells. The reduction in transport velocity is due to the presence of a liquid phase in the NVDR, which lowers the effective permeability to steam, and to the large effective compressibility in the two phase region which better attenuates the pressure wave.

While it appears that there exist potential short-term problems with injection into the HTR, it should also be noted from Figure 5 that their are long-term benefits. For the rate of injection used in the base case, NCG concentrations fell below 2.5 **wt%** within about **6** months of injection, and to less than 1 wt% within one year of injection operations. As is noted below, however, both effects appear to be fairly sensitive to injection rate.

Effect of Injection Rate on CO_2 Production

Several additional simulations were conducted to study the relationship between injection rate and transport of NCGs. **A** total four simulations were run, varying injection rate between 200 tons/hr (200% of initial production) and 50 tons/hr (50% of initial production). The fourth case simulated the process with no reinjection considered. The figures discussed below show only production from well P1 (completed 75% in NVDR). Production from well P2 follows the same general trend.

Mass production rates are given for the four cases in Figure 10. One can readily note the benefits of reinjection from this figure, with the largest injection rate actually leading to an increase in the production rate, even at relatively small times. The effect of injection rate on C02 production is given in Figure 11. This figure helps illustrate the relationship between streamline velocity and C02 production.

Note that the smallest nonzero injection rate results in the formation of two distinct peaks in CO_2 production. **As** discussed earlier, this is a result of production of C02 from the HTR, followed by production of CO_2 from the NVDR. Both of these peaks are substantially broader than in the cases of higher injection rate, and travel at a slower velocity. It appears, then, that a lower injection rate (or use of more injectors for a given amount of injectate), mitigates some of the adverse effects of injection. It may also be, however, that the broader peaks in C02 production observed may result in longer periods of time during which a well produces too large a C02 mass fraction.

What is also interesting is the lack of a second peak in C02 production associated with the largest injection rate (Qinj = 200 ton/hr). **A** C02 profile, shown at t = 0.356, is given in Figure 12, and can be compared with that in Figure 7 (i.e., both are at about peak CO_2 production). In comparing this figures, one can easily note the larger degree of CO_2 displacement associated with the larger injection rate. The chemical wave also travels through the HTR more quickly, and C02 production from the HTR falls rapidly. Some C02 is displaced into the NVDR, and is ultimately produced. However, in this case, the displaced C02 is mixed with nearly gas-free injectate, and therefore the overall CO_2 production rate is low. This is further illustrated in the C02 profile shown in Figure 13, at t = 0.5 yrs. Note the continued large mass fraction of C02 in the NVDR (displaced from the HTR), which is offset by the relatively low C02 fractions in the HTR. Thus, it appears that injection rates have multiple effects on NCG production.

CONCLUSIONS

In summary, we believe that, in addition to substantial long-term benefits of HTR injection, there may be short-term adverse effects as well. These effects seem intuitively simple, yet they have not to our knowledge been reported upon. Both are to somewhat sensitive to injection rate, and may therefore be managed through careful injection design.

It is important to note that the simulations described herein were illustrative in nature, and do not represent the complexity seen in The Geysers. Production/injection rates, travel times, etc., are sensitive to model characteristics (e.g., model dimensions, permeability, porosity, etc.) and should not be taken as being representative the HTR in northwest Geyser. Despite the simplicity of the numerical model used in the current study, it does point out some important aspects of HTR injection. Many additional issues exist which were not addressed in this preliminary study, including the effects of reservoir properties, well spacing, HTR liquid saturation, and fracture/matrix interactions on C02 production. These will be addressed in a future study pending interest of the geothermal community.

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Table 1. Summary of properties used in the study.

<u>Reservoir</u>	
Permeability	50 md
Porosity	0.1
Rock density	2650 kg/m^3
Specific heat	1 kJ/kg
Relative permeabilities:	$S = (S_w - S_{wr}) / (1 - S_{wr})$
vapor	$k_{rv} = (1-S)^{2.5}$
liquid	$k_{rl} = (S)^4$
<u>Numerical</u>	
Grid size	51 x 1 x 24
Grid spacing	Δx = 50 m
	Δy = 100 m
	Δz = 50 m

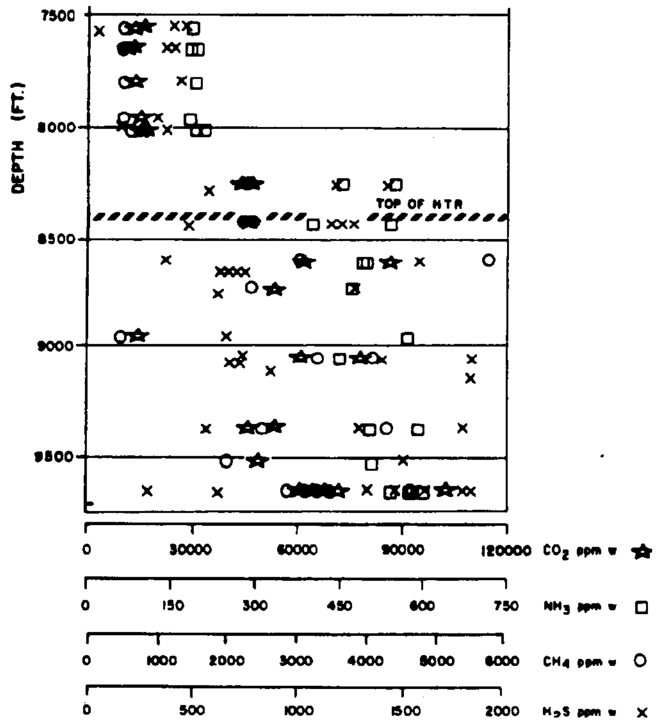

Figure 1. Variation **of** gas concentrations with depth in "well **A**" penetrating the NVDR and HTR from Walters et al. (1988). Collected from the blooie line with air stopped.

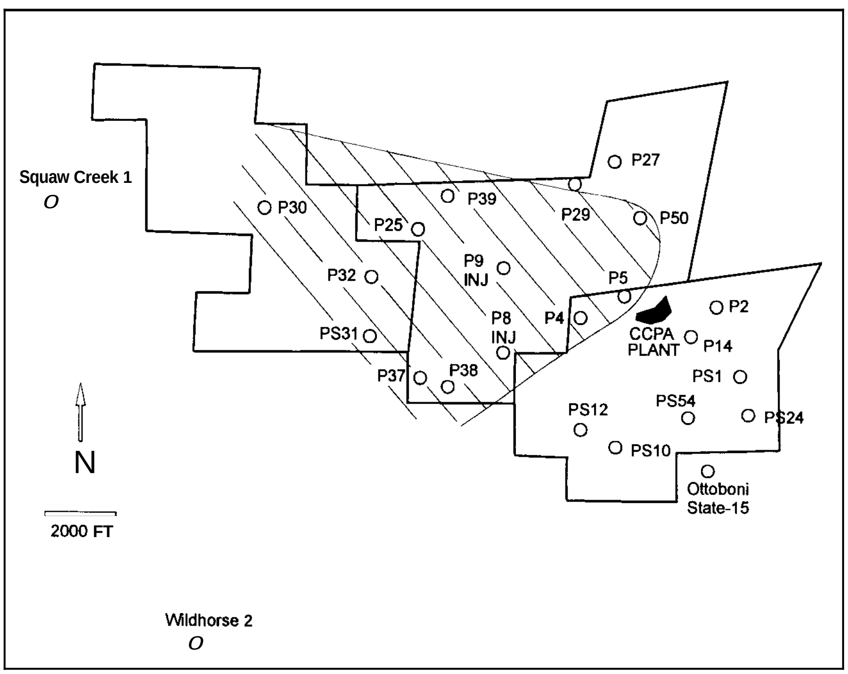

Figure *2***.** The Coldwater Creek field with the area underlain by the high-temperature reservoir (HTR) cross hatched.

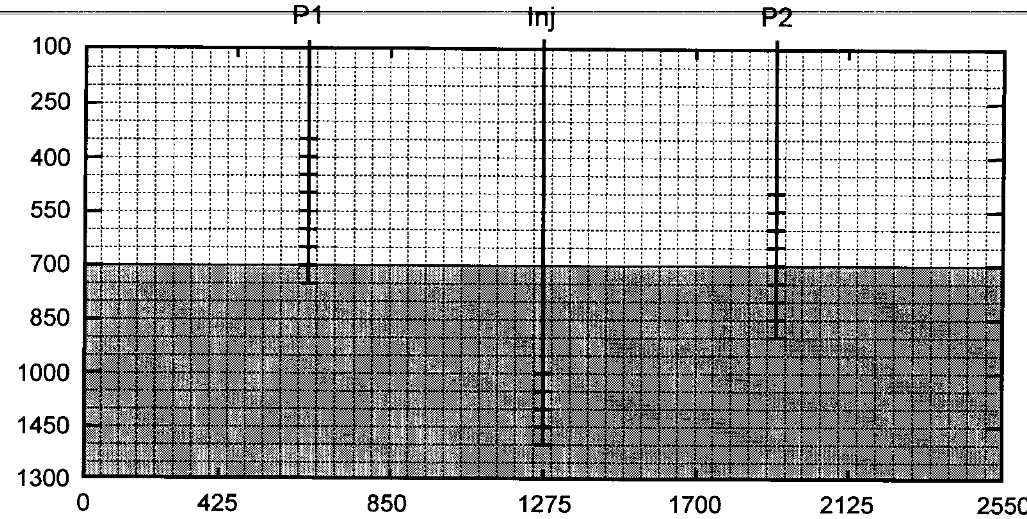

Figure 3a. Two-dimensional, porous media model with the HTR shaded. Grid blocks outlined with dashes. Open interval of production and injection wells are shown by bars. In meters.

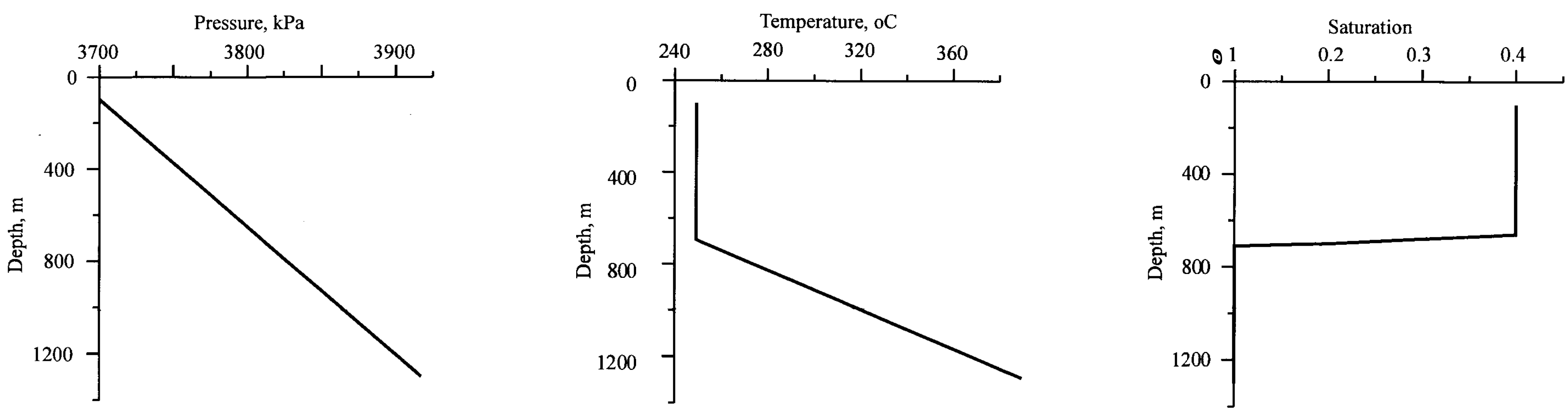

Figure 3b. Initial variation with depth of pressure, temperature and saturation in the model.

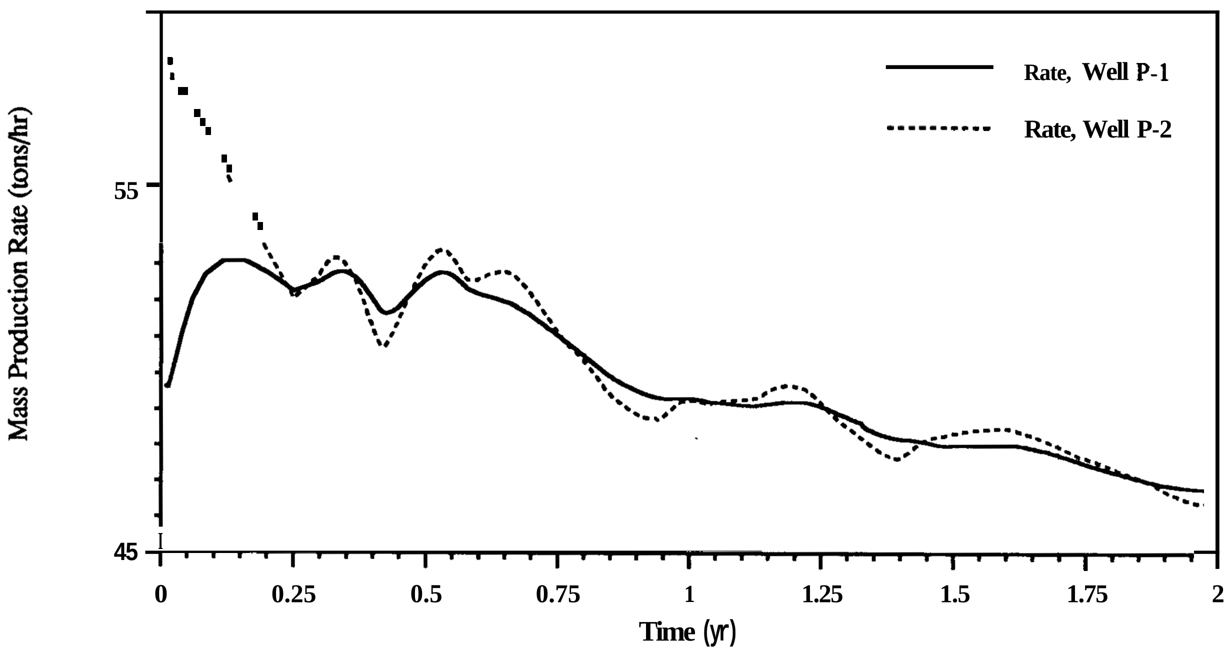

Figure 4. Production rates for base case (100% reinjection of initial production rate)

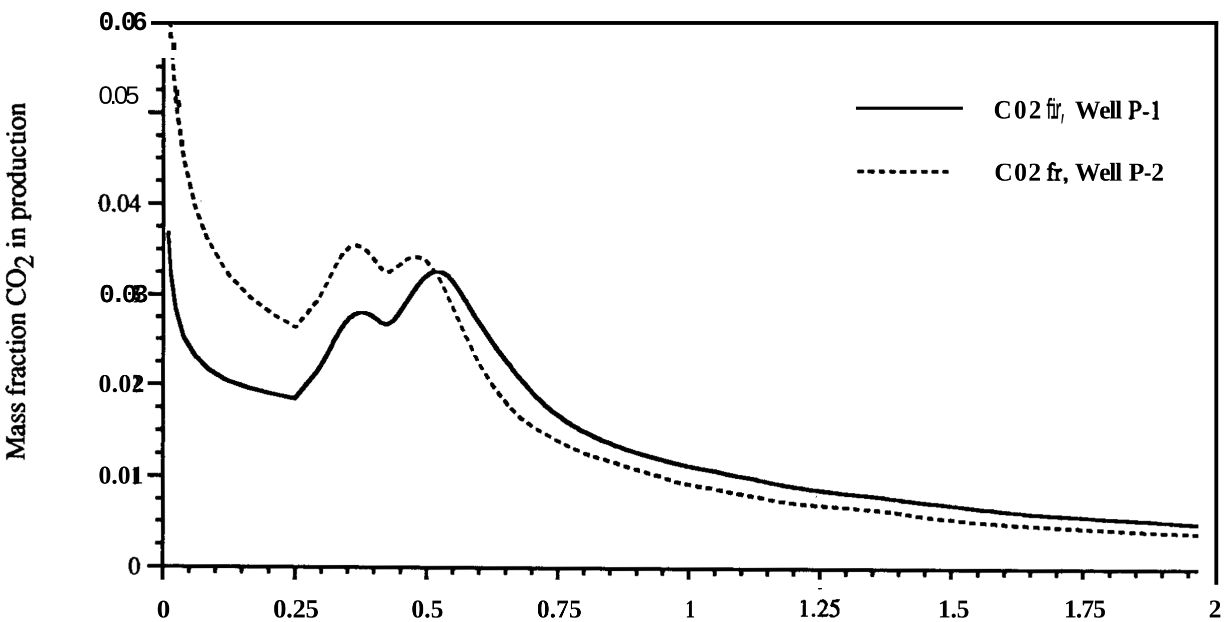

Figure 5. Mass fraction C02 in production for base **case (100% reinjection of initial production rate)**

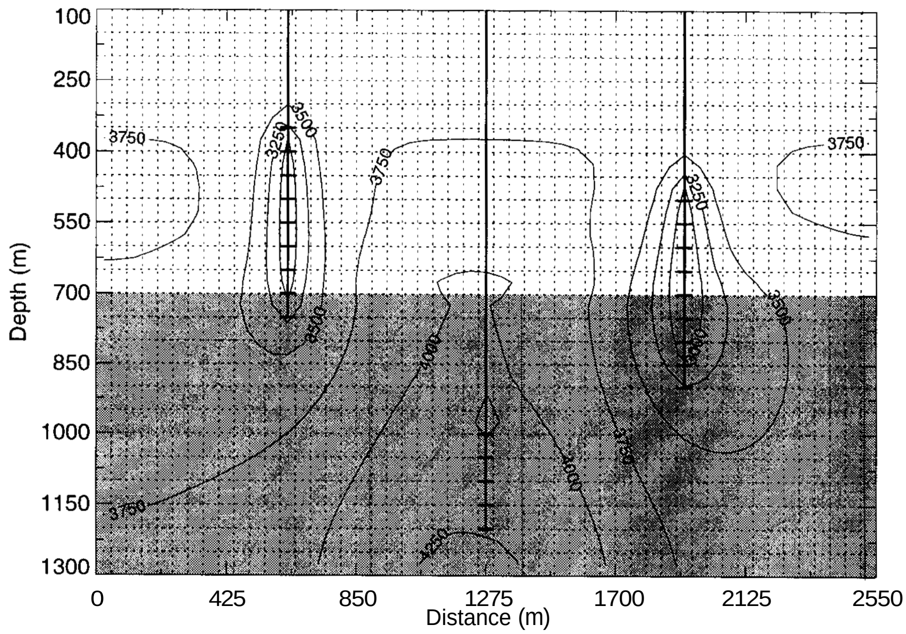

Figure 6. Pressure profile at t = 0.375 yrs (45 days after start of injection), approximately at arrival of pressure wave at Well P-2.

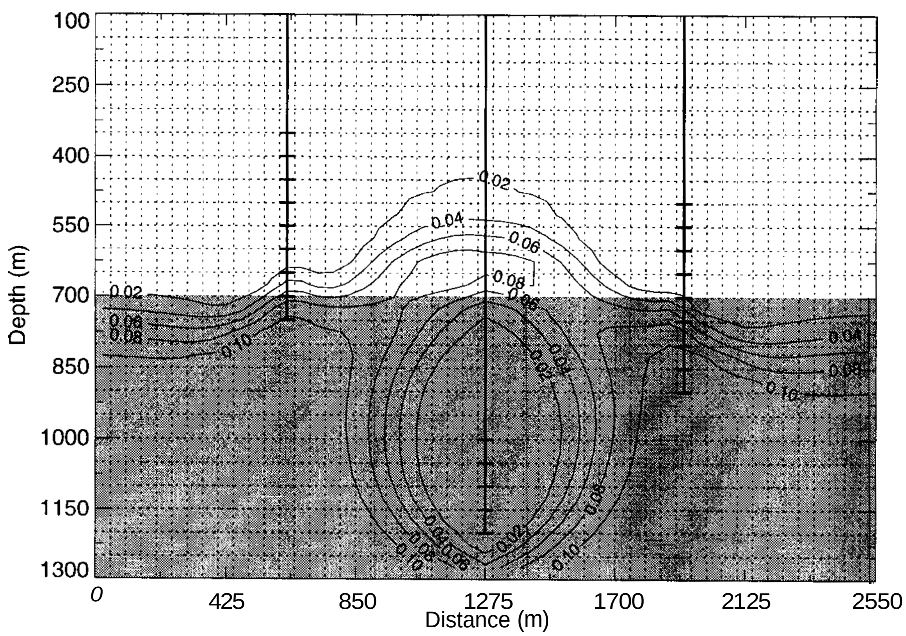

Figure 7. CO_2 mass fraction profile at t = 0.375 yrs.

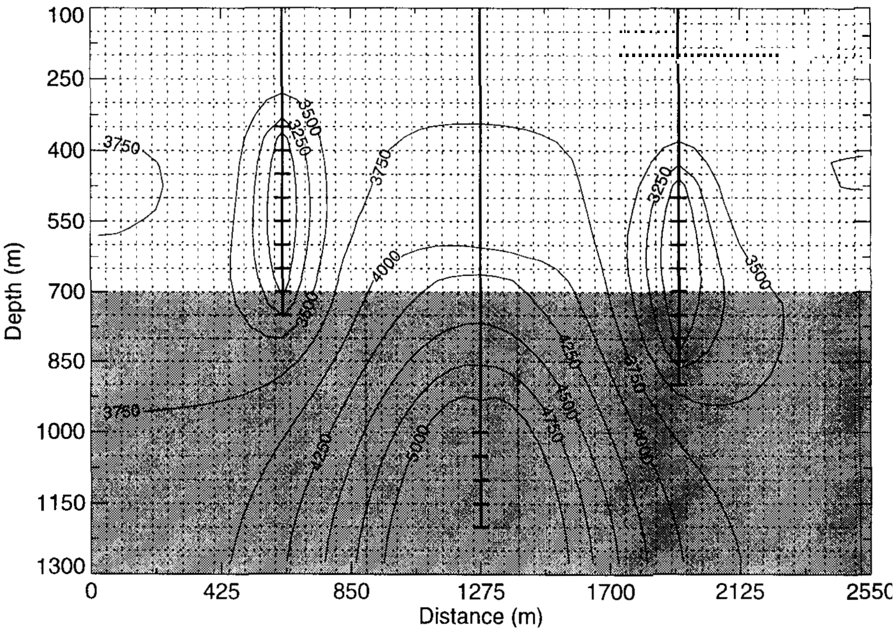

Figure 8. Pressure profile at t = 0.546 yrs, shortly after chemical wave has passed Well P-2.

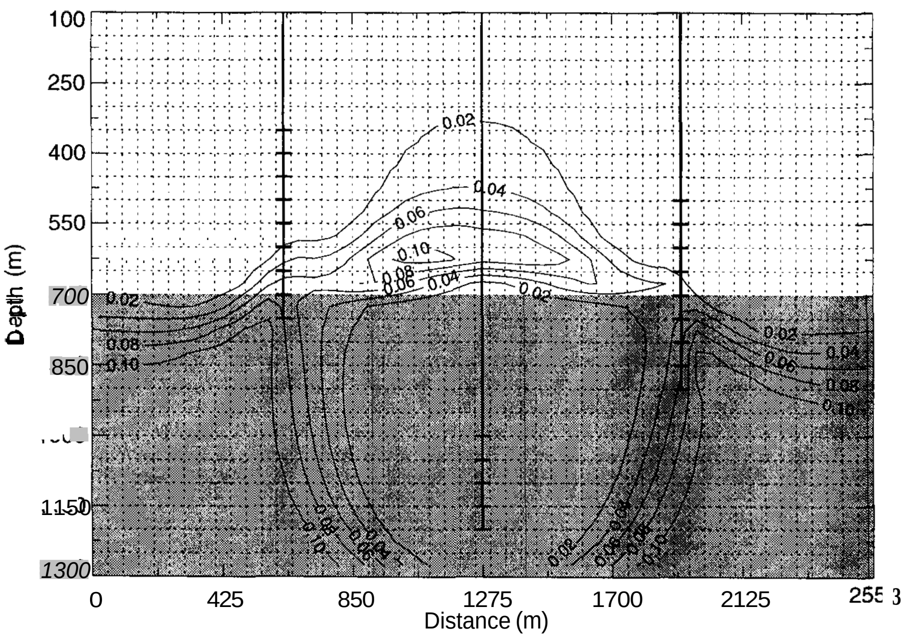

Figure 9. CO_2 mass fraction profile at t = 0.546 yrs.

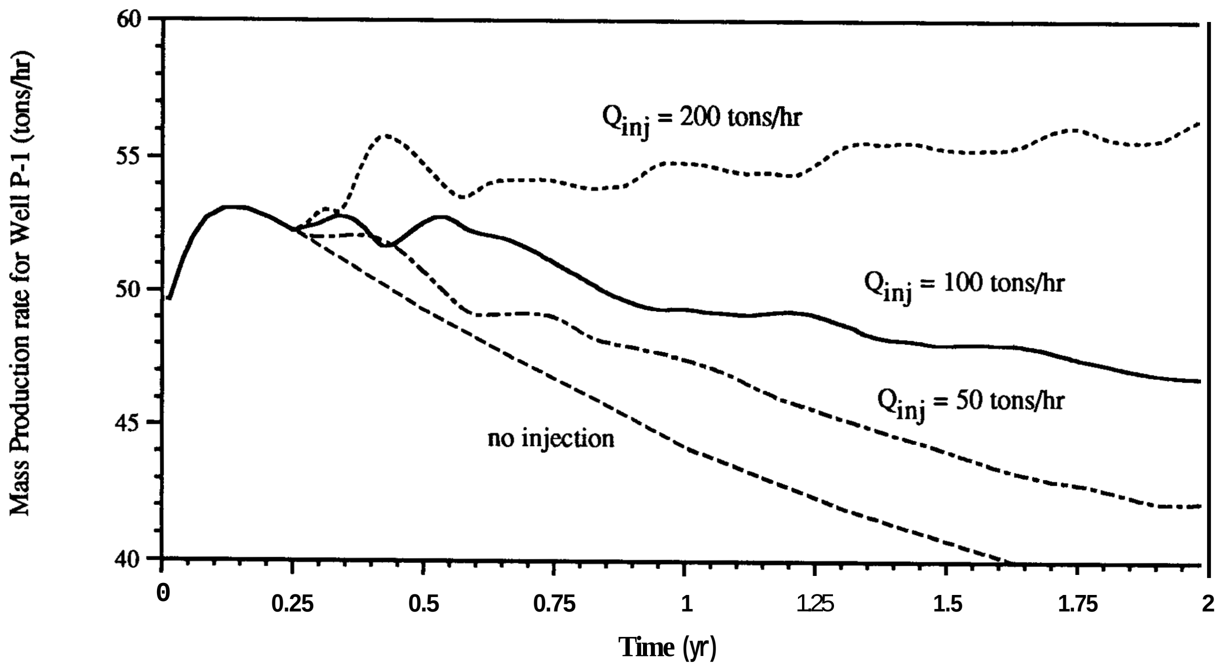

Figure 10. Production rates as a function of reinjection rate.

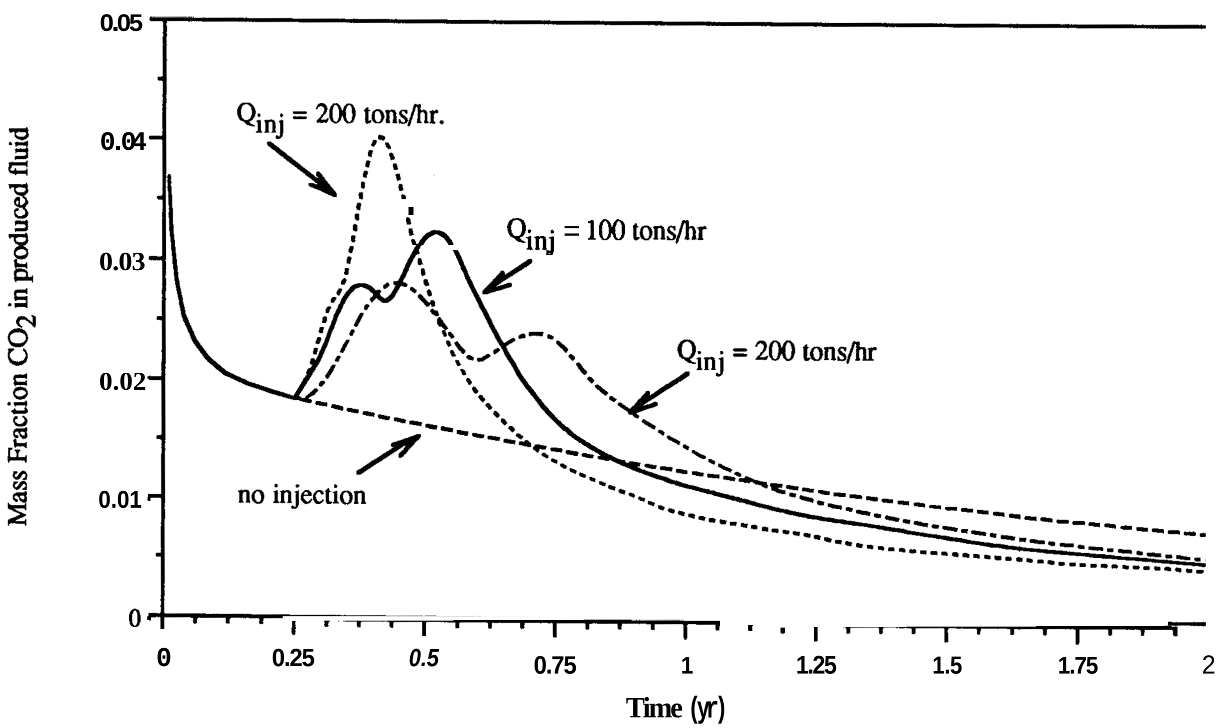

Figure 11 C 0 2 mass fractions in produced fluid as a function of injection.

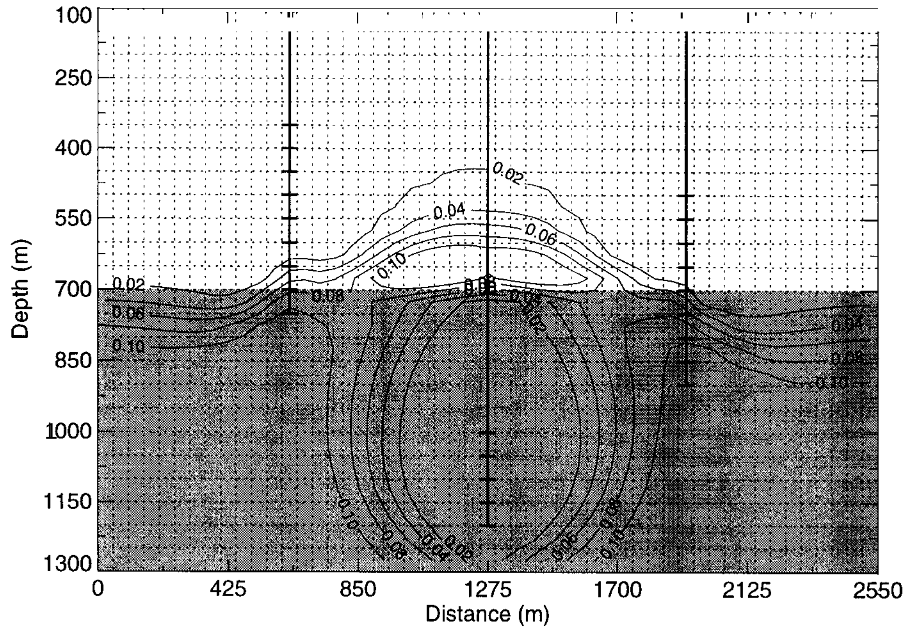

Figure 12. CO_2 mass fraction profile at t = 0.358 yrs. for 200 tonshr injection rate.

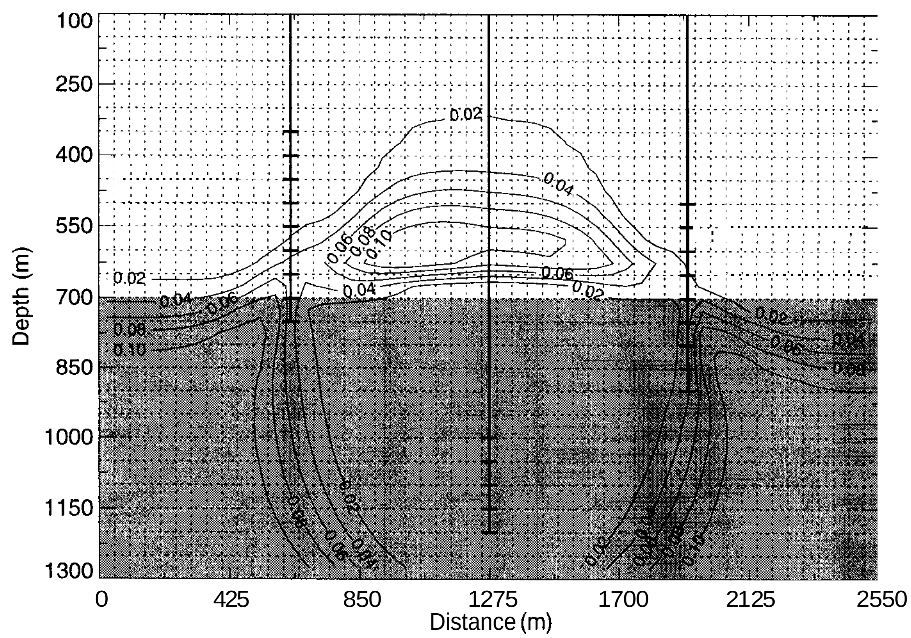

Figure 13. CO_2 mass fraction profile at t = 0.5 yrs. for 200 tons/hr injection rate.