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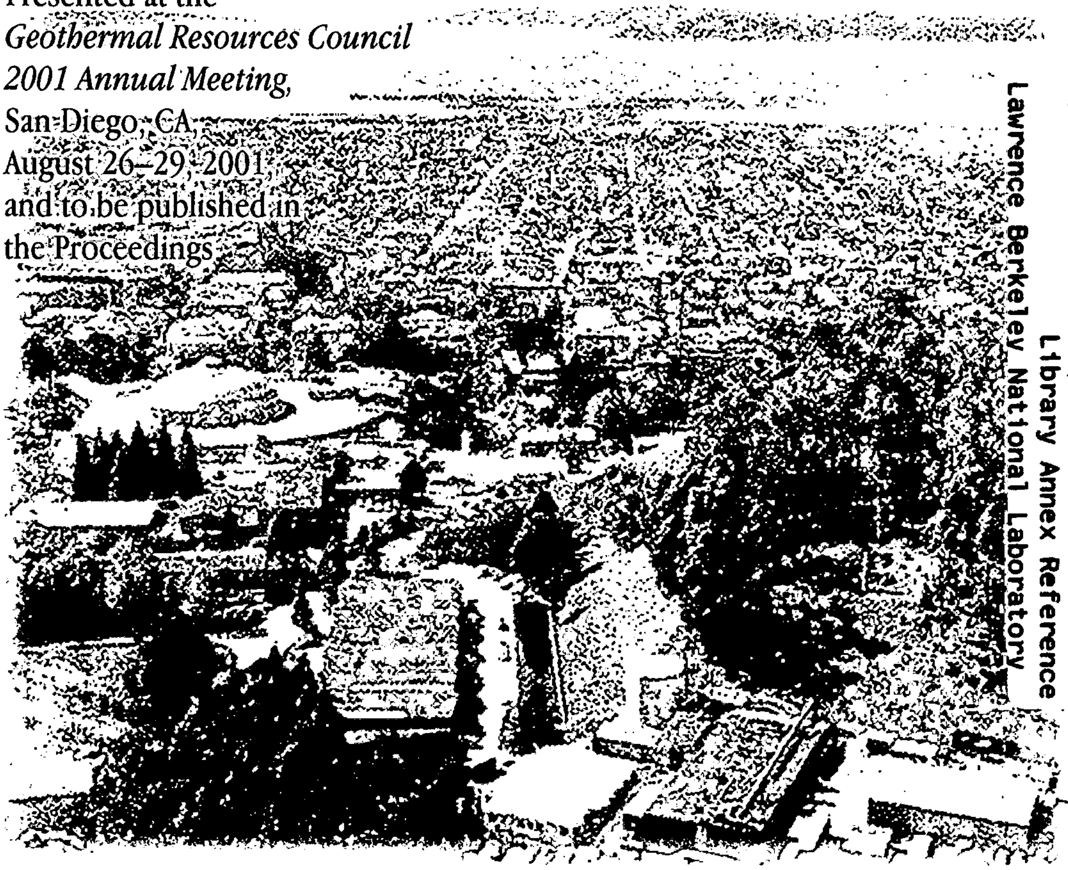

RECENT GEOCHEMICAL TRACING OF INJECTION-RELATED RESERVOIR PROCESSES IN THE NCPA GEYSERS FIELD

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ABSTRACT

The use of non-condensable gases to identify reservoir processes in vapor-dominated fields is illustrated in a study of the changes observed in the steam of the NCPA field at The Geysers, California. Variations of gas ratios in the produced steam explain processes resulting from large-scale production and from an increasing amount of injected liquid, especially after the South East Effluent Pipeline came on line. Changes in the source (i.e., chemical characteristics) of the injectate are useful in the detection of the various phenomena occurring in the reservoir.

INTRODUCTION

The Northern California Power Agency (NCPA) field occupies the southernmost part of The Geysers (Figure 1). After startup in 1983, NCPA first purchased steam from Shell Oil and then Grace Geothermal to supply their two power plants. In 1985 NCPA purchased the entire steam field and was able to coordinate steam production and power generation (Enedy et al., 1990). This has resulted in remarkable efficiency in steam usage and an open attitude toward information exchange and cooperation with outside researchers and organizations. As a result of studies of injection (Enedy et al., 1992), seismicity (Smith et al., 2000), downhole well properties (Enedy, 1992) and steam geochemistry (Klein and Enedy, 1989; Truesdell et al., 1993), the characteristics of the field have become relatively well known. The purpose of this paper is to update studies of steam chemistry to reflect changes resulting from increased water injection after the completion of the SE Geysers Effluent Pipeline (SEGEP) in late 1997 and, not incidentally, to test the applicability of geochemical analysis to a Geysers field with a relatively high rate of injection.

Previous geochemical studies (Klein and Enedy, 1989; Truesdell et al., 1993) have shown that non-condensable gases (NCG) in steam were generally in equilibrium with respect to the methane breakdown and pyrite-H_2S reactions proposed by D'Amore and his coworkers (D'Amore, 1991; D'Amore and Truesdell, 1985). At the time of these studies, injection was limited to steam condensate from cooling towers and what surface water could be collected. Water from these sources was usually less than about a quarter of the water produced as steam. This limited injection was not sufficient to prevent the field-wide decrease in steam pressure and flow that occurred in 1987 as a result of the depletion of reservoir liquid, hastened by accelerated development. At NCPA the decrease of pressure in highly exploited central areas caused inflow of gassy, higher-pressure steam from field margins and increase of gas in central area steam (Truesdell et al., 1993).

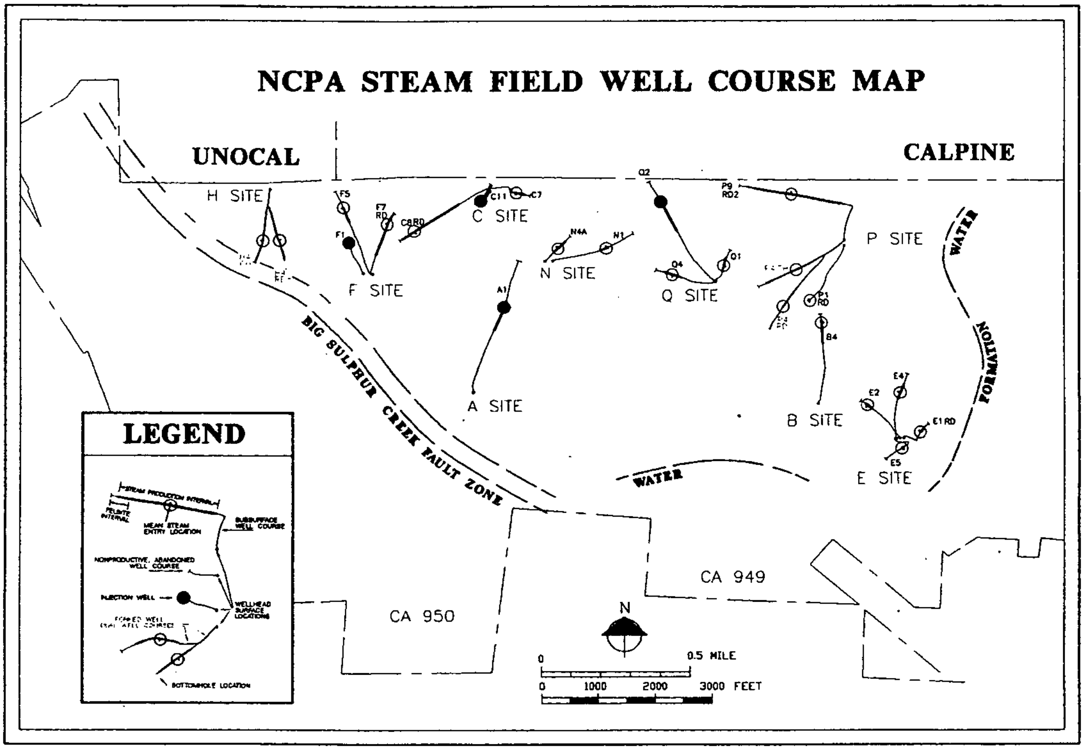

Figure 1. Map of the NCPA Geysers field in the late 1980s showing locations of field boundaries, selected well sites and well courses, mean steam entries and mean injection points (solid circles). Unocal's steam field is now owned by Calpine.

The patterns of injection in the NCPA field have changed since the earlier geochemical studies (Klein and Enedy, 1989; Truesdell et al., 1993). Throughout the entire field operations most injection has been into well A-1 in the west central part of the field. From startup to 1989, A-1 was used along with intermittent use of central injector D-4 and injectors Q-2 and Y-4 on the north and south. From 1989 to 1996 injection in A-1 and Q-2 continued intermittently, and injection expanded to Y-5 in the center and J-6 in the south. After 1996 injection was shifted more to the center with most water injected into wells A-1, D-1, P-1, Q-1 and Y-5. The amount of injection essentially doubled in late 1997 when water from SEGEP reached the field.

ISOTOPE CHANGES

Originally, all Geysers injected liquid was steam condensate that had undergone evaporation in power plant cooling towers. Thus, there was a large and reasonably constant difference in isotopic composition between original reservoir steam and steam derived from vaporization of injectate. This isotopic difference depended on the temperature of the cooling tower and varied with the season (Truesdell et al., 1993), but these differences were minor and the isotopic compositions of steam (particularly deuterium contents) were used to trace the distribution and amount of injection-derived steam.

However some Geysers plants (but not those at NCPA) were modified to lower H_2S emissions by recycling cooling water and direct injection of condensate, instead of circulating that condensate through the cooling towers. This reduced the usefulness of isotopic tracing of injection-derived steam by decreasing the isotopic difference between original steam and vaporized condensate. With the injection of surface waters collected in winter months and particularly the use of waste water from the SEGEP project, the fraction of total injection originating from cooling towers decreased and the average isotopic difference between reservoir steam and injection-derived steam decreased further to the point that isotopic compositions could not be used to trace injection returns.

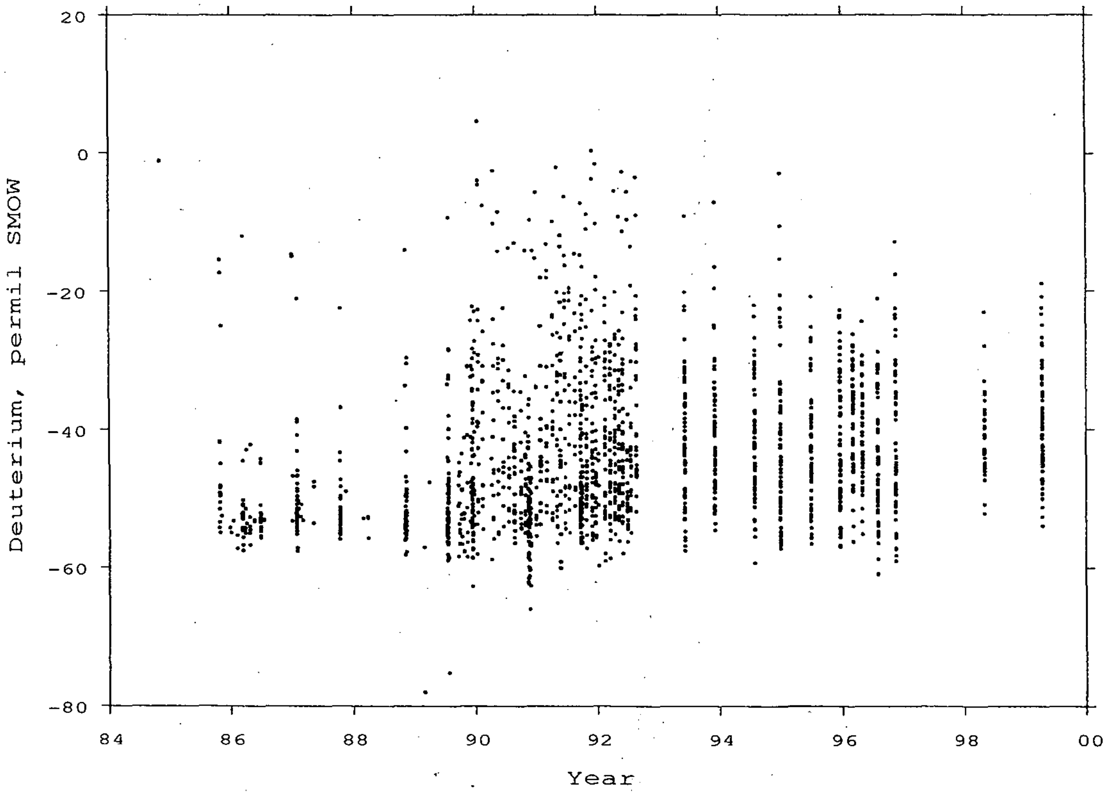

Figure 2. Deuterium analyses of condensed steam and injection water from 1985 to 1999.

The changing origins of produced steam can be seen in Figure 2 in which all deuterium analyses of NCPA steam are plotted against time. There are several processes that can be distinguished. From 1985 to 1989 the range of deuterium in steam was limited to 8 to 9 permil, with minimum δD values near –56 permil. Deuterium compositions of injection waters were about δD = –15 permil. The observed range of δD in steam resulted from variations across the field with more negative values in the east (E pad) and less negative values in the West (F pad). These original differences are mainly due to lateral steam migration from West to East with partial condensation (D'Amore and Truesdell, 1979; Truesdell et al., 1993).

The pattern changed after 1987. Minimum δD values remained the same, but maximum δD values were higher in steam (to –20 permil in 1992) and injectate (to 0 permil). Minimum δD values did not change because little injection was done in the eastern part of the NCPA field where δD values of steam are the most negative. This remained true until about 1998 when access to SEGEP water allowed increased injection. After 1990 surface water was collected in a pond and injected along with the condensate. This had the effect of lowering the δD of the injectate, a trend that continued with addition of SEGEP water. The steam had its lowest δD values in late 1990 because injection was moved from the periphery to the center of the field and because a larger amount of surface water was injected. In 1998 and 1999, the range of δD became more restricted as steam from SEGEP water became an increasing part of the total steam being produced (Figure 2).

Another factor affecting the use of isotopes as injection tracers is that after the 1987 loss of most reservoir liquid, the amount of original steam in the reservoir decreased as the reservoir rocks acted increasingly as a source of heat with vaporized injectate the major source of steam. The change from original reservoir steam to vaporized water from outside sources continued with the introduction of local meteoric water and then SEGEP water. Thus, The Geysers has become largely a hot dry fractured rock reservoir with circulation of an external heat transfer medium (i.e., the injectate as liquid and vapor) to carry heat from the reservoir to the power plants.

GAS EQUILIBRIUM AND CONCENTRATIONS

The geochemical methods used earlier (Truesdell et al., 1993), including D'Amore gas geothermometer grids (D'Amore, 1991; D'Amore and Truesdell, 1985) and changes in total gas contents, have been used to construct time series diagrams for individual wells over the entire period of production. The results show large variations as great or greater than those in the earlier study. Instead of fitting curves to data grouped by wellpads as was done before, here grid diagrams for individual wells are presented and interpreted according to their behavior patterns. As the D'Amore grids are important to the conclusions, their use will be summarized and their limitations explained.

Gas equilibrium calculations

At equilibrium, concentrations of NCG in reservoir steam and liquid are different because gases partition strongly into the steam and because the solubilities of gas in steam and liquid varies between gases. Thus, the composition of a mixture of steam and vaporized liquid, initially in chemical and phase equilibrium, does not correspond to equilibrium in either liquid or steam. However, by combining gas solubility and equilibrium data for two reactions, both reservoir temperature and steam fraction can be calculated. The most used gas reactions are the thermal breakdown of methane,

$CH_4 + 2\ H_2O = CO_2 + 4\ H_2$,

and the conversion of pyrite to hydrogen sulfide,

$3\ FeS_2 + 4\ H_2O + 2\ H_2 = Fe_3O_4 + 6\ H_2S$.

Both reactions are used in the D'Amore gas geothermometer grid diagram with the axes:

$4 \log (H_2/H_2O) + \log (CO_2/CH_4)$, and

$3 \log (H_2S/H_2O) - \log (H_2/H_2O)$.

These quantities calculated from wellhead molar gas ratios for each sample define a point on the grid diagram. The method of calculation and drawing of grid lines of constant reservoir temperature and steam fraction ("y") were described earlier (D'Amore and Truesdell, 1985; Truesdell et al., 1993).

The validity of this approach requires that wellhead steam compositions reflect only the reservoir temperature and the steam fraction. This depends on two assumptions:

1) The wellhead sample is from a single fluid source containing a mixture of liquid and vapor in chemical and phase equilibrium, and
2) There is no change in composition of the fluid mixture during vaporization of the liquid and transport of the steam to the wellhead.

Considering the number of steam entries in most Geysers wells and the forked completions in some, it seems unlikely that these conditions would be exactly met. However the temperatures and steam fractions derived from the grids applied to early analyses seem reasonable (D'Amore and Truesdell, 1985; Klein and Enedy, 1989; Truesdell et al., 1993).

Hypothetical changes in temperature and steam fraction in fluid source zones of individual wells

It is useful to consider how the temperature and steam fraction at the steam source in a Geysers well might be expected to change with production. Early in the study of vapor-dominated reservoirs it was recognized that the major source of steam in these reservoirs was liquid water vaporized by heat transferred from the rock. This process was visualized as occurring in small fractures and pore spaces contained in matrix blocks connected to large fractures in which steam was carried to the wellbores (White et al., 1971; Truesdell and White, 1973).

The water and steam within a matrix block in an exploited reservoir was seen as divided into three zones inward from a large fracture: a nearly isothermal dry zone where all liquid was vaporized, a zone of increasing temperature where the liquid content increased from zero to the original saturation value, and an inner zone with the original liquid saturation and original temperature. In this hypothetical steam source with uniform matrix porosity, the average temperature and steam fraction would be constant as long as all three zones of the matrix continued to exist. Therefore, the points representing produced steam would plot in the same place on the grid diagram.

As liquid in matrix blocks becomes exhausted the average production will be increasingly from existing steam and less from boiling liquid. If the source zone is isothermal then the points will move to higher steam fractions parallel to constant temperature grid lines. If the source zone moves to greater or lesser depths the temperature might increase or decrease, although in vapor-dominated reservoirs the change in temperature with depth is small because the original pressure gradient was determined by the steam density (i.e., a "vaporstatic" gradient).

Injection of liquid water will have complex effects on the average gas composition and therefore on the position of the steam sample on the grid diagram. If injected water were imbibed into matrix blocks at the original depth of production, then steam fractions would increase and temperatures decrease. If injected water moved to deeper zones, both steam fractions and temperatures might increase. Injection could change the source of steam by blocking steam paths. This could produce shifts in position on the grid diagram. All of these scenarios are hypothetical but they may help interpret what we find in the diagrams.

Grid diagrams for individual NCPA wells

Grid diagrams for individual wells of the NCPA field were drawn by a computer program using the equations presented above. There are nearly 70 wells that have been in production from the mid-to-late 1980s up to 1999 or 2000 (data for 2001was not available at the time of writing). It is clearly not possible to describe the grid diagram behavior for each well, but the behaviors have been divided into types (with examples illustrated).

"Linear" and "hairpin" grid diagram behaviors

In "linear" and "hairpin" grid diagrams (see Figures 3 and 4) the points fall generally along a fairly straight line starting at a temperature near 240°C and y between 0.01 and 0.05. In linear diagrams the points trend to higher y values and usually higher temperatures. Steam from well E-1 for example (Figure 3) starts in 1985 at 250°C and y=0.01, in 1986 passes through 230°C and y=0.1, and ends in a cluster of points from 1990 to 2000 near 260°C, with y about 0.2. This suggests processes of drying and heating. This might result from steam originating from a progressively deeper and more water-depleted source. The behavior of steam from wells A-3, A-4, C-2 and C-7 is similar. Although the starting temperatures are near those observed in wells, the maximum temperatures may not reflect equilibrium. Hairpin diagrams start near 250°C and y between 0.01 and 0.1, proceed along paths similar to those of linear diagrams,

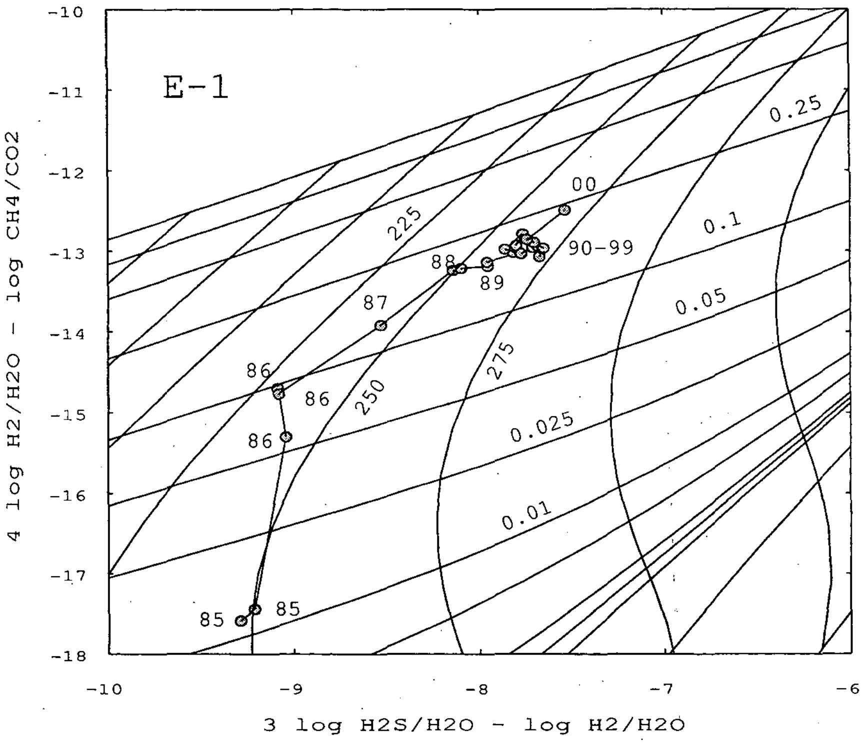

Figure 3. D'Amore grid diagram for steam samples from well E-1 from 1985 to 2000. This well shows "linear" behavior (See text).

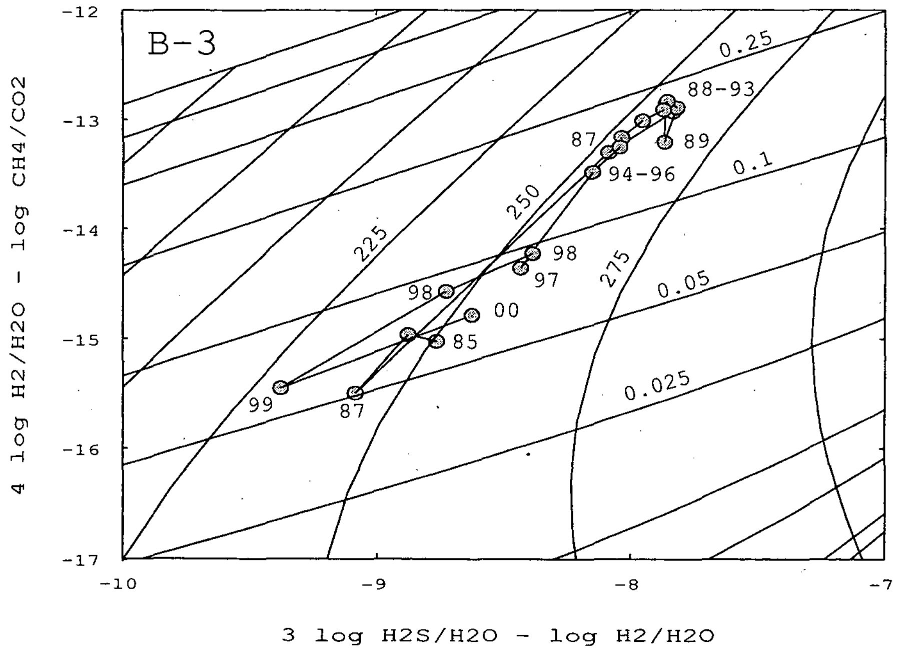

Figure 4. D'Amore grid diagram for steam samples from well B-3 from 1985 to 2000. This well shows "hairpin" behavior (See text).

reach y=0.1 to y=0.25 in the late 1980s to early 1990s, but then turn around to end near their starting points. Well B-3 is an example (Figure 4). This behavior also occurs in wells B-4, E-2 and E-5, and with variations in wells B-2, B-5, E-4, E-6, F-2, P-1 and Q-3. This behavior clearly results from the partial re-watering of the reservoir resulting from the injection of surface water beginning in 1990 and SEGEP water starting in 1997. Equilibrium of vapor and liquid was evidently attained during this re-watering. These diagrams cannot result from just an increase or decrease in total gas because the ratios of individual gases in some cases raised to powers, e.g. $(H_2)^4/CH_4$, $(H_2S)^3/H_2$), not the total gas dominate their behavior.

The increases in indicated temperatures of the steam sources in both linear and hairpin diagrams may result from a deeper and hotter source. The 5-10°C increase shown by several wells could indicate a steam source 1750 to 3500 meters deep based on the temperature gradient of saturated steam in a vaporstatic pressure gradient (Karsten Pruess, pers. com., 2001). This is not directly supported by other data, but seismic studies have shown that microearthquakes caused by injection extend to more than 4 km below sea level NW of NCPA and to about 3 km in the NCPA reservoir itself (Smith et al., 2000).

"Cluster" grid diagrams

On "cluster" diagrams most points fall within a defined group extending over less than the width between grid lines. Y-2 is an example (Figure 5). This type of diagram results from a relatively stable source of injection water. Most wells near injection well A-1 present this behavior. A-1 has been the largest and most consistently used injection well over the entire history of the field. Wells near A-1 with cluster behavior include A-5, A-6, C-6, D-6, N-2, N-3, N-5 and Y2. Many other wells in the central part of the NCPA field also have cluster behavior but with larger excursions. Some grid patterns start linear and end in a cluster, or have a cluster in the middle. Clustered grid behavior indicates that the injection has been fully effective, neither allowing reservoir volumes to dry out or water out.

Grid diagrams can show more than one type of behavior. Well E-1 (Figure 3) starts with "linear" behavior from 1985 to 1988 with a change in y from 0.01 to 0.2 indicating a change to drier conditions. However from 1990 to 1999 it became a "cluster" with little change in "y" and finally in 2000 dried out a little more to a "y" of 0.25. This suggests that the source region during the period of cluster behavior had rather uniform conditions over a volume that could support the flow from the well. Well B-3 (Figure 4) with "hairpin" behavior also formed a cluster from 1988 to 1993 at about the same temperature and y values as well E-1. These wells are fairly close together, but B-3 is closer to injection wells and recovered to original conditions after 1993.

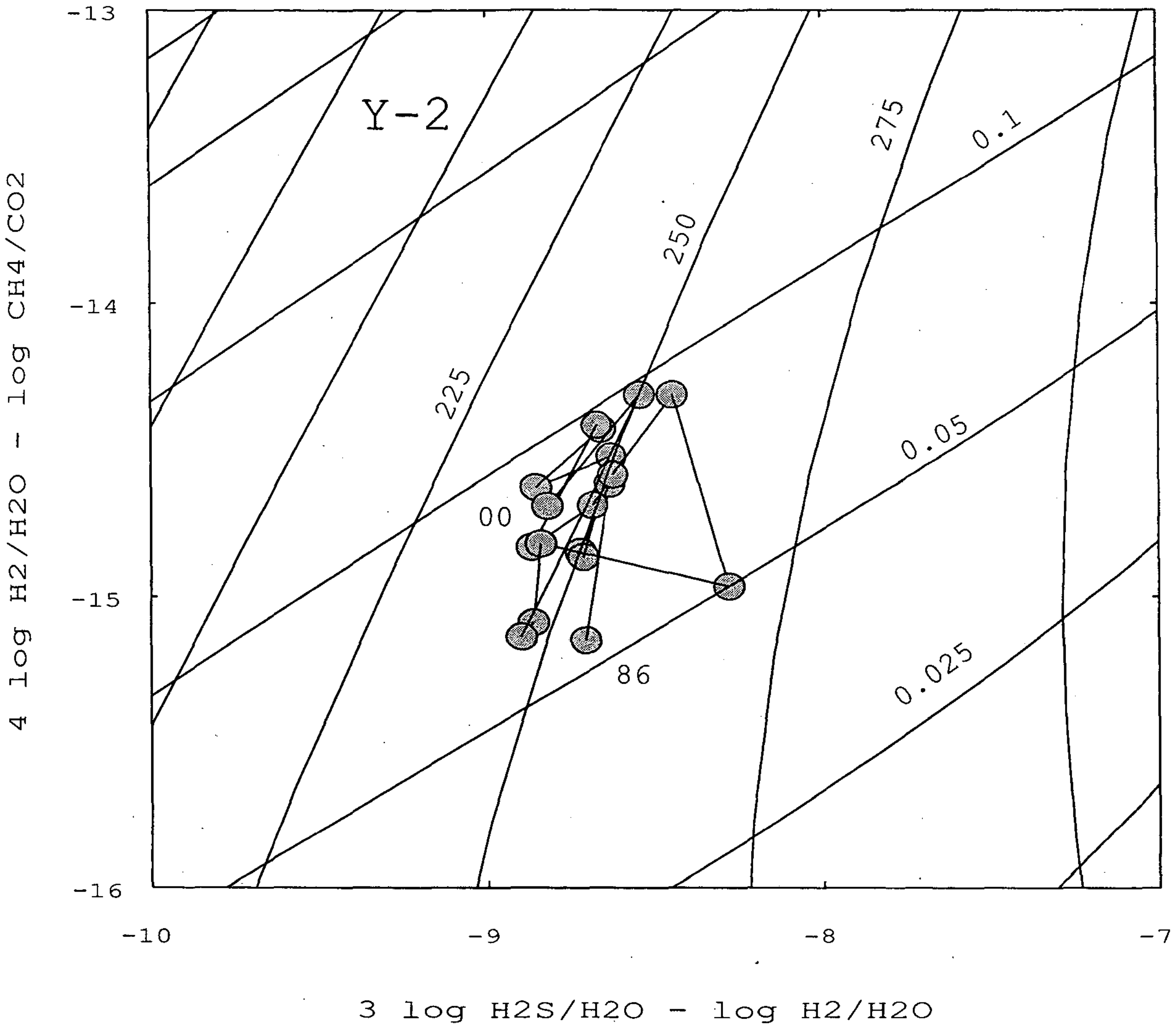

Figure 5. D'Amore grid diagram for steam samples from well Y-2 from 1986 to 2000. This well shows "clump" behavior (See text).

"Random" grid diagrams

Some grid diagrams (or parts of grid diagrams) have behaviors that apparently do not relate to temperatures and steam fractions in the reservoir. These diagrams have large excursions that sometimes exceed the bounds of the grid. In a few cases these excursions occurred when the pattern of injection was changed or the volume injected increased, but most random grid examples are along the northern edge of the field where gas concentrations are very low (e.g., C, H and N wells). Thus the patterns of these grids probably result from partial disequilibrium between gas and recently injected water.

CHANGES IN NONCONDENSABLE GASES WITH TIME

The NCPA field presents a water boundary and high gas steam on its southern and western edges (Enedy et al., 1990). Earlier we showed that in the late 1980s, when there was a field-wide decrease in pressure and steam flow, NCG increased in some parts of the field (Truesdell et al., 1993). In order to see whether the changes in injection practice (and particularly the increase in injection water provided by the SEGEP) have affected the NCG in the field, a series of contour plots have been constructed that show the gas concentrations (in ppm by volume). Figure 6 presents the average gas concentrations in 1986, 1988 and 1990; Figure 7 shows gas data for 1992, 1997 and 2000; the solid circles are injection wells in operation.

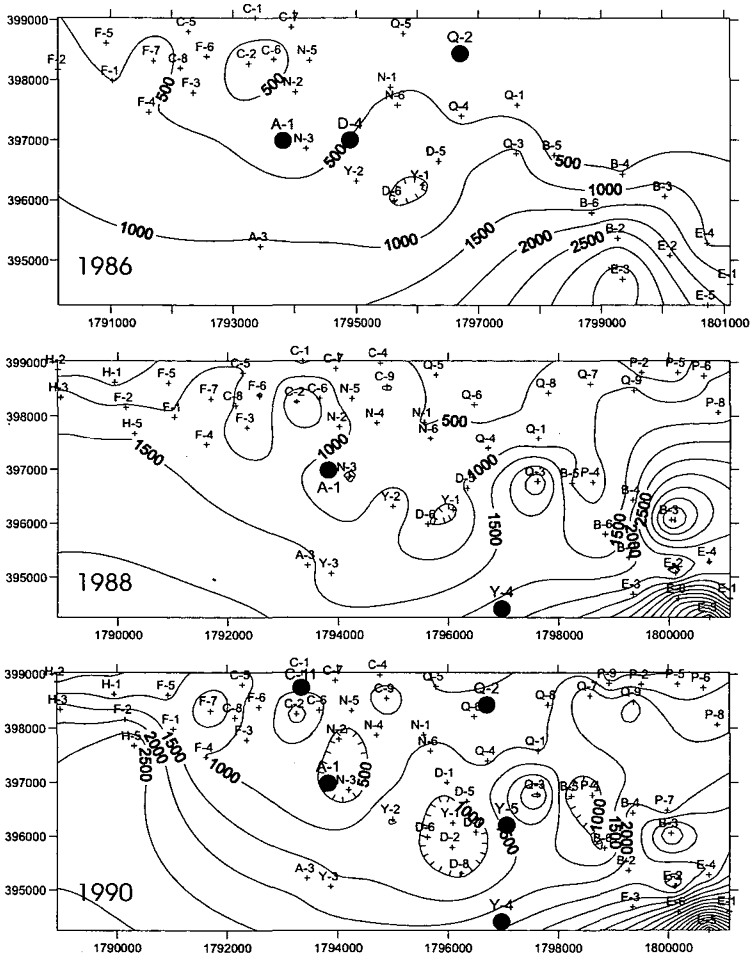

Figure 6. Contours of total non-condensable gas (in ppmv) for 1986, 1988 and 1990. Injection wells in use are shown as large solid circles.

In 1986 (Figure 6) the NCPA field had been operating about three years. Producing wells were in a NW-SE band with few wells in the northeast. The reservoir still contained liquid water and most steam was not significantly superheated. Gas concentrations were 500 ± 300 ppmv for all wells except those in the south and southeast

(B and E wells and wells A-3, and Q-3). By 1988 (Figure 6) more wells had been drilled in the northeast and a few more in the south. Gas concentrations in the field had doubled for most wells (much more for E-5). At this time most of the injection was into wells A-1 and Y-4 with lobes of low gas (<1000 ppmv) coincident with injection. Two years later, in 1990, gas concentrations had increased everywhere except in the center of the field near the injectors A-1, Y-4 and Y-5 (Figure 6). There is an area of gas <500 ppmv near A-1, and an area of gas <1000 ppmv between Y-4 and Y-5. At this point there was not enough injection to stop the inflow of gas from the field margins except near the injectors.

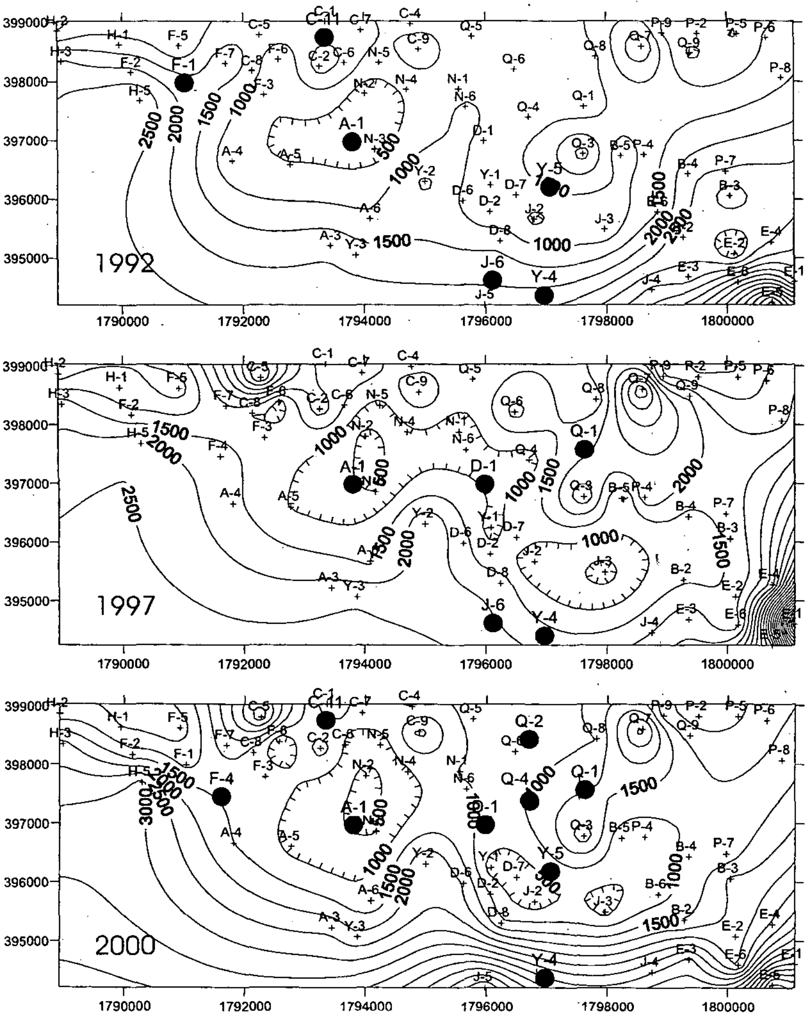

Figure 7. Contours of total non-condensable gas (in ppmv) for 1992, 1997 and 2000. Injection wells in use are shown as large solid circles.

In 1992 (Figure 7) the gas flow from the southern boundary had increased, and steam produced by southern wells doubled in gas content with the highest value from new well J-5. Injection was now into wells A-1, C-11, F-1, J-6, Y-4 and Y-5. Although more injectors were used, the same areas of low gas (<1000 ppmv) near A-1 and Y-4, Y-5 and

J-6 remained. In 1997 (Figure 7) the injection had been moved nearer the center to wells D-1, Q-1, and P-1 which, along with well A-1, resulted in a decrease of gas concentrations over a large part of the central field. This change was made to decrease the average gas in the produced steam since most wells were located in the center of the field. Clearly this change has lowered average gas in the center and northern edge of the field, but gas concentrations have increased in the south. In 2000 after more than two years addition of SEGEP water, the rate of reservoir pressure decline was greatly reduced (NCPA, unpublished data), but gas from outside the drilled area continued to enter along the southern border of the field (Figure 7).

The locations of wells with distinctive grid diagrams (Figures 3-5 and text descriptions) can be compared with the gas contours from 1986 to 2000 (Figures 6 and 7). The linear and hairpin grid behaviors occur for gassy wells in the south and southeast (E, B and some A wells). For these wells there was relatively little injection, and gas equilibrium was maintained. Cluster grid behavior occurs for wells in the center of the field (A, C, D, N and Y wells) with moderate and constant gas maintained by even injection over time. Finally random grid behavior results occurs in the northern edge of the field (F, H and some C and N wells) where original low gas and high injection rates prevented equilibrium.

CONCLUSIONS

The location of the NCPA field at the southern edge of The Geysers reservoir and next to a condensation zone of high gas steam to the East and South, has required careful placement of injection to minimize gas in steam delivered to the power plants. Geochemical methods were used to study the compositions of steam from 1991 to 2000 to supplement earlier studies.

Isotopes of oxygen and hydrogen can indicate the amount of steam derived from injection, although the isotopic contrast between reservoir steam and injectate is decreasing due to increased injection of creek water, Clear Lake water and treated wastewater rather than steam condensate that has undergone evaporation in cooling towers. The application of gas geochemistry to detect and monitor changes with time in the temperatures and steam fractions of steam from individual wells has shown that steam from wells in the center of the field originates from fairly uniform conditions produced by injection. In contrast, steam from wells in peripheral areas originates from progressively drier zones, which may return to near original conditions possibly as a result of changes in the amount or pattern of injection.

The existence of steam with gases that are out of equilibrium may result from 1) mixing during production, 2) too short residence times under stable conditions, or 3) locally large amounts of vaporized, near gas-free injection water that do not equilibrate with remaining liquid. Thus, gas geochemistry continues to provide useful information on reservoir temperature and steam saturation conditions, not otherwise obtainable.

Contours of total non-condensable gas for the NCPA Geysers field show that changes in the location and amount of injection have been very effective in limiting gas concentrations in steam for most production wells. The shift of injection to wells closer to the center of the field has lowered gas in the center and northern part of the field. However, due to the position of the field at the edge of The Geysers reservoir, gassy steam from outside the field continues to enter from the east and south.

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