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VARIATIONS IN DISSOLVED GAS COMPOSITIONS OF RESERVOIR FLUIDS FROM THE COSO GEOTHERMAL FIELD

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ABSTRACT

Gas concentrations and ratios in 110 analyses of geothermal fluids from 47 wells in the Coso geothermal system illustrate the complexity of this two-phase reservoir in its natural state. Two geographically distinct regions of single-phase (liquid) reservoir are present and possess distinctive gas and liquid compositions. Relationships in soluble and insoluble gases preclude derivation of these waters from a common parent by boiling or condensation alone. These two regions may represent two limbs of fluid migration away from an area of two-phase upwelling. During migration, the upwelling fluids mix with chemically evolved waters of moderately dissimilar composition. CO_2 rich fluids found in the limb in the southeastern portion of the Coso field are chemically distinct from liquids in the northern limb of the field. Steam-rich portions of the reservoir also indicate distinctive gas compositions. Steam sampled from wells in the central and southwestern Coso reservoir is unusually enriched in both H_2S and H_2. Such a large enrichment in both a soluble and insoluble gas cannot be produced by boiling of any liquid yet observed in single-phase portions of the field. In accord with an upflow-lateral mixing model for the Coso field, at least three end-member thermal fluids having distinct gas and liquid compositions appear to have interacted (through mixing, boiling and steam migration) to produce the observed natural state of the reservoir.

INTRODUCTION

The recent development of production facilities in the Coso geothermal system has permitted unprecedented geochemical observations of a large portion of the reservoir in nearly its natural state. Unlike most active geothermal systems developed to date, the rapid expansion of facilities at Coso allowed 3-dimensional sampling of fluids from much of the reservoir prior to extensive modification of fluid compositions and distributions by long term production induced effects.

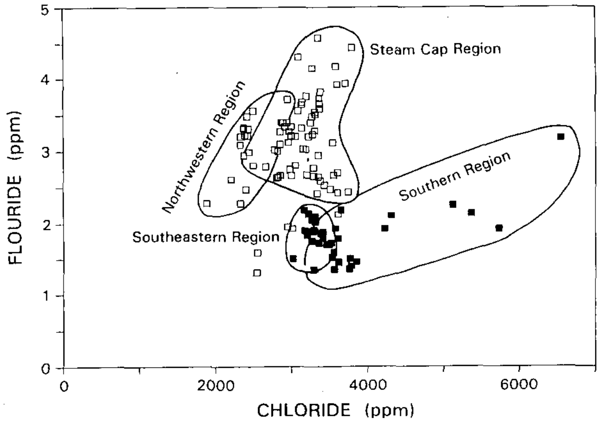
To facilitate the discussion of geochemical sub-regions, four geographical designations will be used in this paper: 1) Northwestern region, including all wells which lie to the north and west of the Devils Kitchen (Fig. 1), an old mercury mine and site of active fumaroles, 2) Steam Cap region, located immediately south of Devils Kitchen, 3) Southwestern region, which includes the hottest wells, and 4) Southeastern region, somewhat to the south and east of the southwestern wells. Figure 1 illustrates these sub-regions as well as the locations of Devils Kitchen and Coso Hot Springs, where upwelling steam and gases have created an assemblage of mudpots and fumaroles.

Although the Coso field has been known for some time because of surface expressions at both Coso Hot Springs and at the Devils Kitchen area, data concerning the deep reservoir chemistry has only recently been acquired. Preliminary studies of reservoir fluid chemistry from two early wells (CGEH #1 and COSO #1) were first reported in Fournier et al. (1980). In their limited sample set (two wells) Fournier et al. (1980) recognized the presence of a Cl^--rich (~2300 mg/kg) liquid-dominated geothermal system which appeared to be relatively homogeneous in chemical composition. Minor variations in the chemical compositions of the fluids sampled from these two wells appeared to be primarily due to temperature dependent cation exchange reactions in the regions tapped by these two wells. Reservoir temperatures of 240-250°C and 205°C were inferred for the COSO #1 and CGEH #1 regions respectively. Their results seemed to indicate that the fumarole and acid-sulfate surface manifestations seen at Coso Hot Springs and the Devils Kitchen (Fig. 1) were only shallow phenomena disguising an alkali-chloride liquid dominated system at depth.

More recently, Moore et al. (1989, 1990) and Williams and McKibben (1990a,b) reported a more detailed picture of the deep reservoir chemistry at Coso as indicated by sampling of numerous production wells. Their results indicate a widespread and variable presence of reservoir steam (much of which may be induced by production) and substantial variations in the natural state chemistry across the field.

Consistent decreases in Cl^- and CO_2 concentrations in analyses from 28 wells and roughly linear Cl-enthalpy relations between deep steam-rich southwestern wells and both shallower wells in the north and liquid-only wells in the southeast (Fig. 1) were observed and interpreted by Moore et al. (1989, 1990) as indicating mixing of rising hot, saline, CO_2 rich geothermal fluids with cooler, dilute groundwaters. They thus interpreted the natural convective reservoir flow as upwelling in the southwest portion of the field then spreading as plumes of mixing fluids to the north and southeast.

Observations of regional variations in concentrations of additional dissolved components in fluids from 47 Coso wells (Williams and McKibben, 1990a,b) indicate that reservoir mixing is not simple. Variations in Cl/B, Cl/F (Fig. 2) and other element ratios indicate that several distinct liquids are present and that end member waters are most likely chemically evolved thermal fluids.



Because of compositional variations induced by mixing, boiling and water-rock interaction within the reservoir, Williams and McKibben (1990a,b) were able to discern as many as five distinct geochemical sub-regions within the Coso reservoir (some shown on Fig. 1 and Fig. 2). Such regional variations illustrate the effects of natural state flow, boiling and mixing and provide ideal natural tracers to monitor production induced changes in reservoir flow.

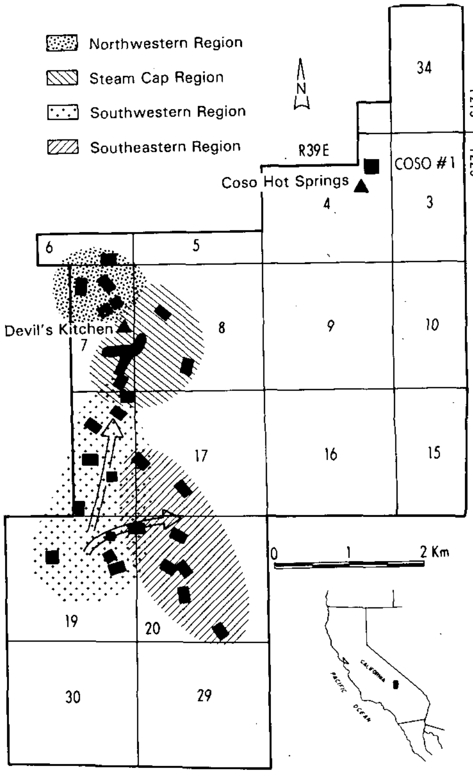


FIGURE 1. Map of the Coso geothermal field, showing well pads (black rectangles) from which multiple directional wells are drilled and surface thermal manifestations (triangles). Geochemically defined sub-regions have been indicated as well as hypothetical fluid flow-mixing directions (arrows).

FIGURE 2. Fluoride vs. Chloride plot of Coso thermal fluids. Geographic regions of distinctive chemistry are indicated for northern well samples (open squares) and southern well samples (filled squares).

PRODUCTION FLUID CHEMISTRY

At this time, 151 analyses provided by California Energy Co. Inc. (CECI). of fluids from 47 Coso geothermal wells are being utilized for our interpretations. The majority of the samples were gathered during initial production testing of wells, so accurate measured enthalpy data also exist. Many additional analyses exist for liquid samples from the midsection of the field. Due to interlaboratory inconsistencies however, this data has been excluded from our present interpretations. A sufficient number of accurate analyses from this region exist to roughly characterize its chemistry. For 110 samplings, complete gas analyses are available. These have been augmented by additional samplings by UCR for specific (CO_2, H_2S) gas concentration and isotope measurements.

Where possible, well-head liquid and steam samples collected using a miniseparator have been recomputed to provide reservoir concentrations. In two-phase reservoir regions, and zones of production induced excess enthalpy however, such recalculations can become quite inaccurate. For this reason some of our discussion will rely on raw well-head gas ratio and concentration data.

Analyses show significant and consistent regional variations in the chemistry of both the fluids and the gases analyzed. In this paper we will present data and provide interpretations of the variations observed in gas analyses of the steam phase of producing wells.

Gas Geothermometry and Estimates of Reservoir Steam

Complete gas analyses of well-head steam samples have been shown useful in estimating both reservoir temperature and steam fraction (D'Amore and Panichi, 1980; D'Amore and Celati, 1983; D'Amore and Truesdell, 1985). Since the Coso system includes two-phase reservoir regions, the approach of D'Amore and Truesdell (1985) was deemed most appropriate for this study. Using gas ratios involving CO_2, CH_4, H_2S, and H_2, reasonable reservoir temperatures and useful steam fraction relations are generated. Regional groupings similar to those developed from other fluid chemical studies (Williams and McKibben, 1990a,b) are also apparent in this gas ratio plot (Fig. 3).

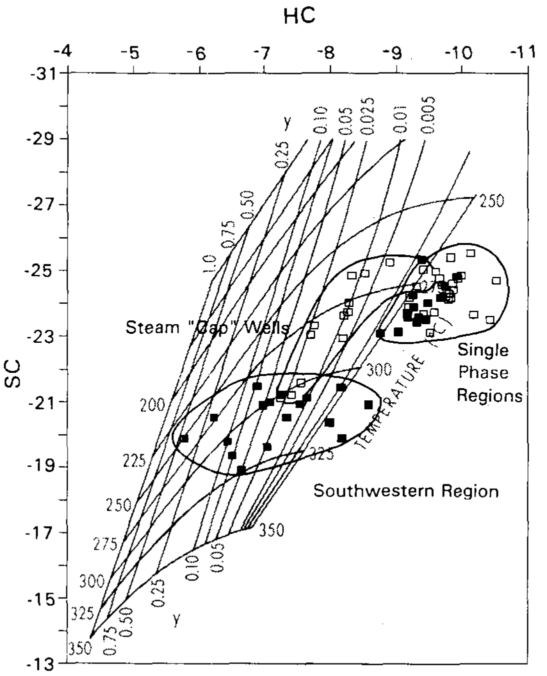


FIGURE 3. Gas ratio plot (after D'Amore and Truesdell, 1985). Symbols as in Fig. 2. Grid gives computed reservoir temperatures and steam fractions (y).

Using molar ratios for Fig. 3, (after D'Amore and Truesdell, 1985):

$$SC = 6 \text{ Log } H_2S/H_2O - 0.5 \text{ Log } CH_4/CO_2$$

$$HC = 2 \text{ Log } H_2/H_2O - 0.5 \text{ Log } CH_4/CO_2$$

Shallow wells producing from the naturally occurring steam "cap" in the northern region of Coso (Williams and McKibben, 1990a,b), show relatively low temperatures (~275° C) and significant reservoir steam fractions (Fig. 3). The deep, high enthalpy wells in the southwestern region, however, show far higher temperatures (300-325° C) and variable, but generally very high reservoir steam fractions, in accord with well-head enthalpy measurements (Moore et al., 1989, 1990; Williams and McKibben, 1990a,b).

It is interresting to note that despite extreme differences in gas concentrations (Moore et al., 1989, 1990), gas ratios imply single phase reservoirs and similar temperatures (~275° C) for wells in <u>both</u> the southeastern and northern regions.

If significant steam loss occurred in the evolution of either of these liquids, subsequent gas re-equilibration must also have taken place to give the observed relationships.

Single-Phase Reservoir Regions

Significant and systematic differences in reservoir gas concentrations are seen between the two liquid-only regions of the Coso field. For instance, CO_2 concentrations in northern portions of the Coso reservoir are nearly three times lower than those found in liquid phase wells in the southeastern region (Fig. 4). Methane concentrations behave in a similar manner, but other gases (H_2, Ar, H_2S and N_2), do not show as significant depletions (Fig. 4). These gases span a wide range of liquid-steam partitioning at geothermal temperatures and the observed relationships appear to preclude derivation of these single-phase fluids from a common parent by boiling or condensation alone. To illustrate this, we have included concentration trajectories (using gas partition relationships from Giggenbach (1980)) for hypothetical reservoir boiling (arrows on Fig. 4). Steam losses of 7 to 25 % at temperatures of 280-340° C respectively are necessary to traverse the plotted trajectories. It is apparent from this and other similar plots that northern and southern fluids cannot be related to a common parent by boiling alone.

A less obvious, but quite significant regional difference in gas ratios can be seen in a plot of well-head nitrogen vs. argon concentrations (Fig. 5). It is apparent that, for a wide array of wells sampled and analysed over several years, Ar/N_2 ratios (Fig. 5) are consistently lower in all southern wells (both single and two-phase) than in northern wells. Geothermal fluids are generally of meteoric origin (in equilibrium with air), and often show Ar/N_2 ratios similar to the .017 value of air (Hulston and McCabe, 1962; Ellis and Mahon, 1977). Such values are observed for all northern Coso geothermal fluids but far lower ratios (typically less than .010) are observed for fluids from southern regions. It is unreasonable to assume that such a consistent pattern would be produced from sampling or analytical errors. Thus, there appears to be either an argon deficiency or a nitrogen excess in the southern Coso reservoir. Although a small variation in this ratio could come from extensive boiling, this regional variation more likely indicates an intrinsic difference in the fluids from these two portions of the field. Little data is available concerning concentrations of these gases in other geologic environments, but possible sources of variability may be; 1) volcanic gas input to the deep geothermal fluid, or 2) organic-rich sediments.

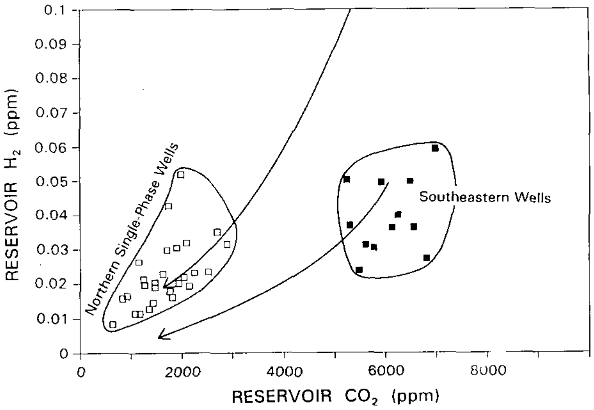


FIGURE 4. Plot of reservoir H_2 and CO_2 concentrations for liquid-only regions. Arrows indicate hypothetical gas loss trends for aprox. 300° C. closed system reservoir boiling.

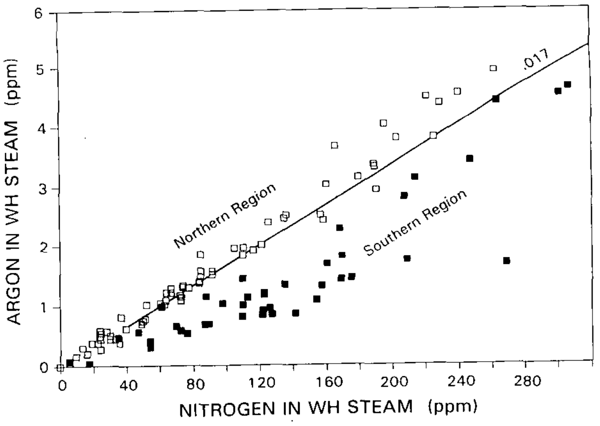


FIGURE 5. Argon and Nitrogen concentrations in wellhead steam samples from northern (open squares) and southern (filled squares) Coso wells. Line (.017) indicates Ar/N_2 ratio of air.

Subsurface hydrothermal alteration and the present existence of a steam "cap" in the northern limb of the Coso field indicate some degree of boiling and substantial degassing of fluids in these sub-regions (Moore et al., 1989, 1990). However, both gas ratio analysis (Fig. 3) and gas concentration plots (Fig. 4), argue against gas loss as the sole mechanism for creating the regional reservoir gas concentration gradients. Instead, we feel it is likely that different thermal fluid end members provide much of the chemical signature (Fig. 2; Fig. 4) which distinguishes fluids in different regions. Significant differences in the Ar/N_2 ratio, particularly between northern and southeastern Coso reservoir regions (Fig. 5) also supports the presence of end member thermal fluids with distinctly different chemical signatures.

Two-Phase Reservoir Regions

Both the steam cap region and the southwestern region of Coso (Fig. 1) are generally known as two-phase portions of the reservoir (Moore et al., 1989, 1990; Williams and McKibben, 1990a,b) although not all wells show reservoir steam contributions. It is not obvious if the two-phase regions represent areas of natural state reservoir boiling or are results of pressure decreases associated with production. Physical evidence and production data support the existence of a natural steam cap in the north, which expanded with increased production. Physical evidence concerning the natural state of the southwestern region is less clear. Early pressure-temperature surveys indicated a single phase liquid reservoir but some aspects of hydrothermal alteration and geochemistry imply a two phase state.

Two-phase reservoir samples show extreme variations in gas composition. A plot of CO_2 vs. H_2S concentrations for all steam samples corrected to represent total produced fluid compositions (Fig. 6) indicates five distinct groupings having recognizable gas concentrations and H_2S/CO_2 ratios. Two of these groups represent the liquid-only regions in the northern and southeastern regions of Coso. They plot in the extreme lower, left-hand corner of this diagram. Steam-rich well data typically fall on a linear array having an H_2S/CO_2 ratio of approximately .015, but a small cluster of two-phase wells (all located in the south-central portion of the field near the common corner of sections 17,18,19 and 20; Fig. 1) indicate somewhat lower ratios. Steam-rich wells tapping the shallow steam "cap" in the northern region of Coso form another cluster at relatively low gas concentrations.

Data from wells in the northern steam "cap" appear compatible with reservoir boiling and steam separation (at temperatures less than 275° C) from liquids equivalent to those in nearby single phase wells.

Utilizing the gas partition equations of Giggenbach, (1980), it can be easily shown that gas concentrations and ratios of the <u>southwestern</u> two-phase wells cannot be produced by boiling any known Coso single-phase liquid at reasonable reservoir temperatures. A gas concentration trajectory (arrow) is illustrated as an example (Fig. 6).

In order to identify fluids produced from homogeneous sources we have cross plotted well-head gas and solute concentrations (Fig. 7). On such a diagram, progressive partitioning between coexisting steam and liquid phases traces an hyperbolic curve as boiling proceeds. Single phase reservoir production data provide examples of such curves. Asymptotes of such curves give starting reservoir solute and gas concentrations.

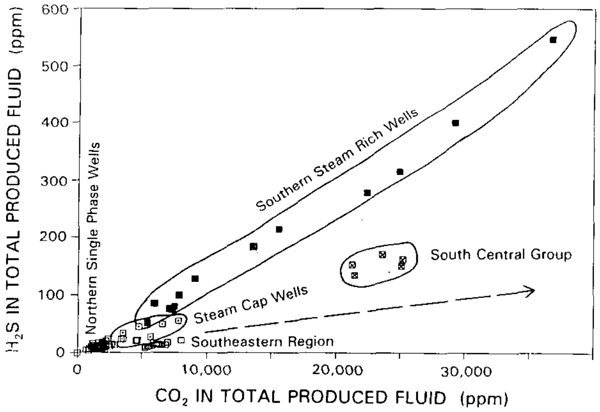


FIGURE 6. H_2S vs. CO_2 content of total production from Coso wells. Regional groupings have been indicated and an approximate 300° C. boiling trend (arrow) for known Coso reservoir liquids is shown.

Although data is sparse, there appears to be no simple correlation between CO_2 and Cl- concentrations in the samples from southwestern Coso wells. There is thus no single homogeneous reservoir fluid from which these wells produce. It is therefore most reasonable to view their gas concentrations (the linear array on Fig. 6) as a mixing line between known Coso geothermal fluids and a relatively homogeneous vapor having concentrations of CO_2 and H_2S of at least 40,000 and 600 ppm respectively. This steam component is most likely contributed directly to production from gas-rich steam in the reservoir. The small group of south-central wells shown on Fig. 6 appear to have a somewhat more complex origin. As shown on Fig. 7, these analyses follow a well defined hyperbolic curve implying as much as 30 % steam loss. Such compositions illustrate boiling of a liquid with Cl^- of approx. 3500 ppm and CO_2 of approx. 25,000 ppm. Unless this curve is fortuitous, it most likely represents boiling of an homogeneous mixture of southwestern and southeastern liquids.

SUMMARY

Interpretation of data from well-head sampling of geothermal fluids at Coso provides an excellent 3-dimensional picture of the natural state distribution of dissolved solids and gases across the field. Gas concentrations and ratios in particular, permit us to evaluate potential mechanisms for producing the diverse chemical signatures seen in Coso fluids.

Two distinct fluids occupy single-phase reservoir regions in the northern and southeastern portions of the field, and it appears unlikely that these fluids could have been produced directly from a common parent since their distinctive chemical signatures preclude evolution from a single hydrothermal liquid by boiling or dilution alone. At least two chemically distinct geothermal end members are required.

A third geothermal fluid is required to provide the observed deep reservoir steam which has extremely high H_2 and H_2S concentrations. Fluids sampled early in the production history of the Coso field represent natural state mixtures of these three end member liquids, steam produced by reservoir boiling, and residual boiled liquids.

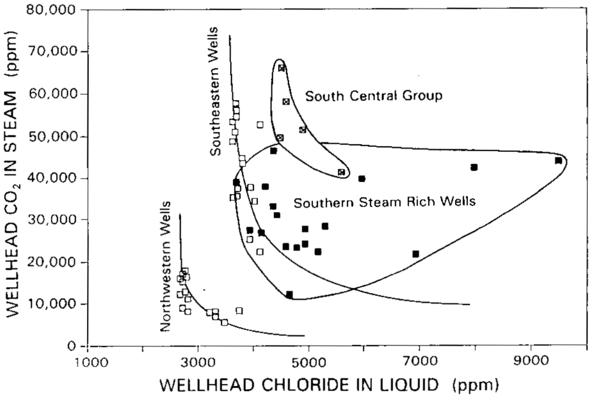


FIGURE 7. Wellhead concentrations of Cl in liquid and CO_2 in steam have been plotted. Hyperbolic curves produced by progressive boiling of homogeneous liquid regions are shown. Scattered data indicates variable boiling and mixing of different reservoir fluids.

The wide variations in reservoir chemistry document the effects of natural state flow, boiling and mixing in the Coso field and provide natural tracers with which to monitor production induced changes in the reservoir.

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