

Application of Fluid Inclusion Stratigraphy Analysis to Geothermal Systems

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## APPLICATION OF FLUID INCLUSION STRATIGRAPHY ANALYSIS TO GEOTHERMAL SYSTEMS

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**SUMMARY** – We report on the application to geothermal systems of Fluid Inclusion Stratigraphy (FIS) analysis developed for the oil industry. Borehole cuttings are collected at 6 m spacing and fluid inclusion gases analysed in vacuum by mass spectrometry; the cost is comparable to other logging methods at about US\$6,000 to US\$10,000 per well. Geothermal system FIS analyses show fracture locations and indicate general fluid inclusion gas chemistry and gas ratios from which fluid type, seal locations and fluid boiling are inferred. Locations of fluids with elevated H<sub>2</sub>S and benzene are determined. Fence diagrams are constructed that show geothermal system fluid stratigraphy.

### 1. INTRODUCTION

Procedures for bulk analysis of drill cuttings fluid inclusions was patented by Dr. Michael Smith and AMACO in the early 90's for the purpose of mapping subsurface rock (Hall, 2002). Today Fluid Inclusion Technologies (FIT), Broken Arrow, OK, offers Fluid Inclusion Stratigraphy (FIT) analysis. A second lab was purchased and made the property of Chevron Oil Company. The principal application of FIT analyses is to find oil pay zones. We hypothesized that FIS analyses can be used to map geothermal systems because alkaline chloride reservoir fluids, steam-heated waters, and shallow bicarbonate waters have different gas chemistries. The cost of an FIS analysis per well is US\$6,000-US\$10,000, which is less than most common logging methods. Hence the promise of geothermal system FIT analysis is that it can yield information about locations of reservoir fluids, fractures and cold water entrants that can aid in decisions on well completion.

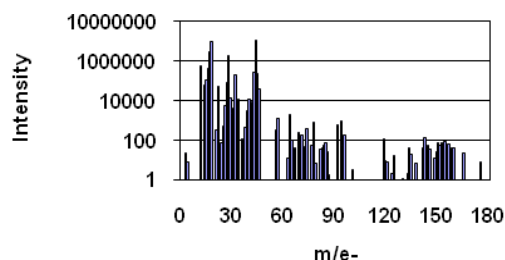
Mapping geothermal fluids by FIT analysis is not as simple as mapping hydrocarbon-bearing fluids. Hydrocarbons are trapped in mineral overgrowths formed during fluxing of hydrocarbon-bearing fluids. Hydrocarbon mass spectra are easily recognized and differ markedly from groundwater gaseous species that maybe in pre-existing inclusions. Geothermal waters, on the other hand, have similar gaseous species as groundwaters, and therefore are distinguished by differences in gas chemistry, gas concentrations (gas/water ratio), and gas ratios like N<sub>2</sub>/Ar. Of added concern is the occurrence of inclusions that predate the present geothermal system, and the effect they have on geothermal system FIT analyses. Our working hypothesis is that fluid inclusions in geothermal system country rock are being continually destroyed because of high strain rates (Moore et al. 1987), and that there should be a high density

of Recent fluid inclusions on and near fractures systems transporting geothermal fluids. This study also addresses the obstacle of interpreting mass-processed FIT analyses that are not calibrated against known gas mixtures, and in general how to best present FIT analyses for interpretation. Here we discuss FIT analyses of 36 wells from 5 geothermal fields and show how these analyses can be used to map geothermal fluids, identify fractures, and determine if wells can be productive.

Distinctive gases assemblages are used to determine fluid types. Reservoir fluids that are deep circulating alkaline chloride waters (Henley, 1984) typically have N<sub>2</sub>/Ar ratios > air, CO<sub>2</sub>/CH<sub>4</sub> > 10, H<sub>2</sub>S that is in near equilibrium with pyrite and magnetite, and propene > propane (Norman et al., 1996, Norman and Musgrave, 1997; Norman et al., 2004). Shallow cooler fluids have N<sub>2</sub>/Ar ratios typical of meteoric waters that are 32 to 54 (although boiling can increase this ratio to about 100), and generally have propane > propene. Steam-heated waters have elevated amounts of the more soluble gas species such as H<sub>2</sub>S, CO<sub>2</sub>, and benzene. Steam caps have inclusions rich in gaseous species and have much less water than assemblages of aqueous inclusions (Moore et al., 2001). Fluids from organic-species-rich rock commonly have elevated concentrations of organic compounds. Mixed fluids are postulated to have the shared characteristics of several fluid types. Boiling creates inclusions with trapped vapour, which results in higher gas/water ratios than assemblages of aqueous inclusions. Condensation results in higher concentrations of more soluble gaseous species that include H<sub>2</sub>S, CO<sub>2</sub> and aromatic organic species; boiling and condensation both result in increased CO<sub>2</sub>/N<sub>2</sub> ratios.

## 2. METHODS

Analyses are performed by first cleaning the samples, if necessary, then crushing a gram-size sample in a vacuum. The volatiles released are pumped through multiple quadrupole mass spectrometers where molecular compounds are ionized and separated according to the mass/charge ratio ( $m/e^-$ ). Electronic multipliers detect the signal, which is processed creating a mass spectrum for each sample. The output data for each sample is the magnitude of mass peaks for masses 2 to 180. A volatile like  $\text{CO}_2$  has a gram formula weight of 44 and will be measured by a peak at mass 44. FIT's lab returns the raw data within three weeks, however upon request this time can be reduced to a few days. Typical mass spectra for geothermal cuttings show mass peaks up to  $\sim 160 m/e^-$  with intensities ranging up to 8 orders of magnitude (Fig. 1). Analysis of hundreds of replicate analyses combined with analysis of NM Tech fluid inclusion standards HF1, SC1, and SB1 indicate a FIT precision of about 26%. Most details of FIT analyses are proprietary, however examination of FIT analyses indicate their mass spectra show less ionization fragmentation than standard mass spectra done with a 70V ion acceleration voltage (NIST, 2007).



*Figure 1: FIT analysis of chips from Coso well 39C-10 5420 ft (1652 m) illustrating peak intensities varying by up to 8 orders of magnitude and mass peaks that extend to  $> m/e^- 160$ .*

## 3. RESULTS

We plot analyses on mud log plots using the Rockware LOGGER<sup>®</sup> software using two graphs. Graph 1 shows mass peaks of common aqueous species and their fragments illustrating changes in gas chemistry with depth (Fig. 2). The data are separated by type and colour-coded. Within each group analyses are arranged by molecular weight. Columns are labelled by species and/or mass of the peak. Common inorganic species He,  $\text{H}_2\text{O}$ ,  $\text{N}_2$ , Ar, and  $\text{CO}_2$  are plotted in blue. Organic alkene and alkane compounds from methane to hexane are plotted in red. Sulphur species  $\text{H}_2\text{S}$  (mass 34) and  $\text{SO}_2$  (mass 48) are plotted in yellow. The column labelled  $\text{SO}_2^+$  is mass 64 the principal peak for  $\text{SO}_2$ , however we observe organic peak interferences on mass 64. Aromatic

hydrocarbons are plotted in grey; mass 50 is a common aromatic species fragment, the other peaks represent cyclopentane, benzene, and toluene.

Graph 2 (Fig. 3) shows gas ratios that we use to interpret volatile source. Graph 2 the “Fluid” group in blue which includes total water, total gas and the gas/water ratio which are used to infer fluid boiling and steam caps. The “magmatic” group of volatile ratios, illustrated in red are the indicators of deep circulating fluids that have a magmatic component, which include the  $\text{N}_2/\text{Ar}$  if  $> 100$ ,  $\text{CO}_2/\text{CH}_4$  if  $> 10$  and two composite ratios R1 and R2 defined respectively as  $(\text{N}_2/\text{Ar} + \text{CO}_2/\text{CH}_2)/(\text{propane/propene (mass 43/mass 39)})$  termed Ratio 1, and  $(\text{N}_2/\text{Ar} + \text{CO}_2/\text{N}_2)$  called Ratio 2. In green are plotted ratios indicating surficial or crustal fluids that include  $\text{N}_2/\text{Ar}$  if  $< 100$ ,  $\text{CO}_2/\text{CH}_4$  if less than 10, propane/propene (mass 43/mass 39 and  $1/\text{R1}$ ). The last group in orange,  $\text{H}_2\text{S}$ ,  $\text{H}_2\text{S}/\text{water}$ , and  $\text{CO}_2/\text{N}_2$  are used to determine condensate. We plot analyses with a smooth curve linking data points. That leads to some confusion particularly in plots of  $\text{N}_2/\text{Ar}$  ratio. Ideally when an  $\text{N}_2/\text{Ar}$  peak is plotted on the “Magmatic” scale (Fig. 3) there should be no  $\text{N}_2/\text{Ar}$  information plotted on the “Crustal” scale, but because of the peak smoothing feature this is not always the case.

Scaling for each mass peak or gas ratio is determined by calculating the mean and standard deviation for measurements from several wells generally comprising 2000 or more analyses. Each mass or mass ratio is scaled so that the graph maximum is the mean  $+2\sigma$ , and that scaling is used for all subsequent analyses done for that geothermal system.

Of particular concern is the interpretation of mass peak 28. The molecular weights of  $\text{N}_2$ , CO,  $\text{C}_2\text{H}_4$ , and organic fragment  $\text{C}_2\text{H}_4^+$  are all 28. In addition the principal gaseous species in geothermal waters is  $\text{CO}_2$  and when ionized in a mass spectrometer it yields a mass 28 fragment  $\text{CO}^+$ . Carbon monoxide is a minor species at geothermal temperatures and organic species commonly are at ppm concentrations (Norman et al., 2004), hence the principal interference when measuring  $\text{N}_2$  using peak 28 is the  $\text{CO}_2$  fragment. In order to establish that mass peak 28 is mainly  $\text{N}_2$  we plot mass peak 28 vs. 14, a principal fragment peak of  $\text{N}_2$ , and mass peak 28 vs. 44, the principal peak of  $\text{CO}_2$ . The strong correlations between mass peaks 14 and 28 indicate they both represent  $\text{N}_2$ . The test is routinely done for all analyses. The low ionization fragmentation in FIT analyses explains why we can use peak 28 to estimate  $\text{N}_2$ . Mass peak 32 correlates with 16 indicating both peaks represent  $\text{O}_2$ . Hence we use mass 15, a major fragment of  $\text{CH}_4$ , to estimate that species. Oxygen is a minor

gas in the background; it could be from air trapped in chip fractures. However, mass 28 and 32 do not correlate indicating that neither the 28 or 32 peaks are not both air. The mass 32 peak is generally so low that the  $^{18}\text{O}$  peak interference with the  $\text{H}_2\text{S}$  peak at mass 34 is less than 1%.

Two Beowawe, Nevada wells, 57-13 and 77-13 were provided. Well 77-13 drilled in 1984 intersects a Basin and Range structure at 5,500 ft (1672 m) and produces from beneath the fault. Well 57-13 was drilled in December 2005 and January 2006 to 10,500 ft (3200 m) to intersect the fault at a different location. It could not be established if the fault was intersected. FIT analysis of the drill cuttings from the two wells was done during which the drill rig was held on standby. Figure 4 shows the results.

We assume the peaks in mud log plots represent fractures (Fig. 2 & 3). Fluids fluxing along fractures should generate primary inclusions in deposited minerals and secondary inclusion in pre-existing minerals. This supposition is confirmed by systematically sampling inclusions across 20 fractures in geothermal drill core. Rock near fractures has higher amounts of inclusion volatiles (Dilley and Norman, 2007). Figure 5 shows an analysis of Steamboat well 87-29 plotted alongside a log showing open fractures. FIT analyses show the open fractures, and in addition the analysis show locations of fractures now mineralized and closed.

#### 4. DISCUSSION

The water peak is used to compare the number of inclusions opened for analysis, because fluid inclusions typically are 99%+ water. Water is poorly measured by FIT. The small burst of water vapour released when inclusions are crushed strongly sorbs onto vacuum system walls, which attenuates the 18 peak. FIT measures peak heights rather than integrating the peak, hence an FIT ratio of peaks 18/44 that should be about 100 is typically about 1 (Fig. 1). Neither the less we find the water measurement useful for indicating if material is inclusion rich or poor in aqueous inclusions, and to illustrate relative gas/water ratios. Figure 3 illustrate that both the water peak and water/total gas ratio show considerable variation from analysis to analysis.

To determine fluid stratigraphy, mudlog plots are examined and lines are drawn separating vertical intervals that exhibit similar chemistry. For Coso well 15A-17 (Figs. 3 & 4) we draw lines at 2500 ft (762 m) and 4900 ft (1762 m). The upper and middle zone differs in relative amounts water, argon, heavy organic species, total gas, gas/water and sulphur species. There is dramatic change in  $\text{N}_2/\text{Ar}$  and gas/water at 2500 ft. At 4900 ft the amounts of sulphur species, aromatic species, and

$\text{H}_2\text{S}/\text{water}$  decrease. The high gas/water ratio and high total gas in the upper unit argues for a steam cap. Some water peaks low in the unit can be explained as condensate. The elevated  $\text{N}_2/\text{Ar}$  ratio suggests the volatiles are from boiling deep fluids not found at greater depth in the well. This suggests that the upper steam and condensate originate elsewhere.

The middle fluid has the characteristics of steam-heated water with elevated sulphur species, elevated aromatic species, and elevated  $\text{CO}_2/\text{N}_2$ . The  $\text{N}_2/\text{Ar}$  ratios of this fluid indicate a shallow ground water source. The lower unit has  $\text{N}_2/\text{Ar}$  like the middle unit but appears to not have been exposed to a significant steam flux. The few fractures in the lower unit, no evidence of boiling, and low  $\text{N}_2/\text{Ar}$  suggest this well would at best be a marginal producer of low enthalpy fluids below 4900 ft. Production is favoured in the middle unit because of the greater fracture density.

Sharp changes in fluid chemistry are interpreted as seals. In reality these may be clay caps. Certainly there is impermeable boundary at 2500 ft (762 m) in Coso well 15A-17 because of the dramatic changes in fluid gas chemistry over 20 feet depth. We have looked for changes in gas chemistry in 14 Coso wells coincidental with changes in rock type and found none (Dilley et al., 2003).

Production intervals, cold water entrants, and well quality can be inferred from the plots. Wells that do not produce generally show some combination of few fractures, lack of evidence for fractures with fluids typical of the reservoir fluids, or show numerous fractures of fluids with gas chemistry typical of shallow waters. Interpretation of wells in each system improves by examination of multiple wells and having as much information as possible about the field. Locations of high  $\text{H}_2\text{S}$ - and benzene-bearing fluids can be inferred from FIS analyses so the fractures that produce such fluids can be cased off.

Fluid stratigraphy can be traced to adjacent wells. We have constructed fence diagrams for the Coso field where 24 wells have been analysed. There is not room to show such diagrams, but fence diagrams for the Coso field and a 3-D model may be found in Norman (2005).

Coso well 68-20 was used as an injection hole for 4 years until it lost permeability. This well and the redrill well 68-20RD alongside 68-20 were analysed (Norman et al., 2005). Injection fluids were gas free. FIT analysis of well 68-20RD show lower gas/water ratios that is pronounced at the injection point and below. These analyses indicate up to 50% of the original inclusions were destroyed or replaced by gas-free liquid. This

supports our working hypothesis that geothermal fluid inclusions are in part ephemeral.

The FIT analyse for Beowawe production well 77-13 (Fig. 4) shows a major fracture at about 5,500 ft. We assume that is the Basin and Range fault that appears to be a fractured zone about 500 ft (152 m) wide not accounting for the unknown fault dip. Below the fault the water signal (light blue column) remarkably increases indicating many more aqueous inclusions in the rock unit in the footwall rocks. The well 55-13 analyse is remarkable similar which indicates that both wells cut a similar structure. The major difference between the analyses is that the organic peaks are much more pronounced in the 53-13 analysis. Both show high amounts of light organic and aromatic compounds on the major fractures, both show a wide fracture zone and both show water in analyses of footwall chips. We reported that the fault was intercepted at almost the same depth as the older drill hole, which turned out to be correct.

We used several approaches to verify interpretations of fluid type during the initial phases of this work. Interpretations of Coso wells were made without benefit of logging and the results presented to Coso geothermal field scientists and engineers for critique. Temperature logs are also used to verify interpretations. Hot water entrants and cold water entrants into a well inferred from temperature logs are compared to FIT interpretations. Figure 5 shows excellent agreement between the temperature log and the FIT analysis that shows a seal at 230 ft (70m).

## 5. CONCLUSIONS

Fluid Inclusion Stratigraphy can be applied to geothermal wells and shows stratigraphy in geothermal fluids and identifies fluid type. It shows location of fractures and major faults, boiling and location of steam caps. Fence diagrams can be constructed that illustrate geothermal system structure.

## 6. ACKNOWLEDGMENTS

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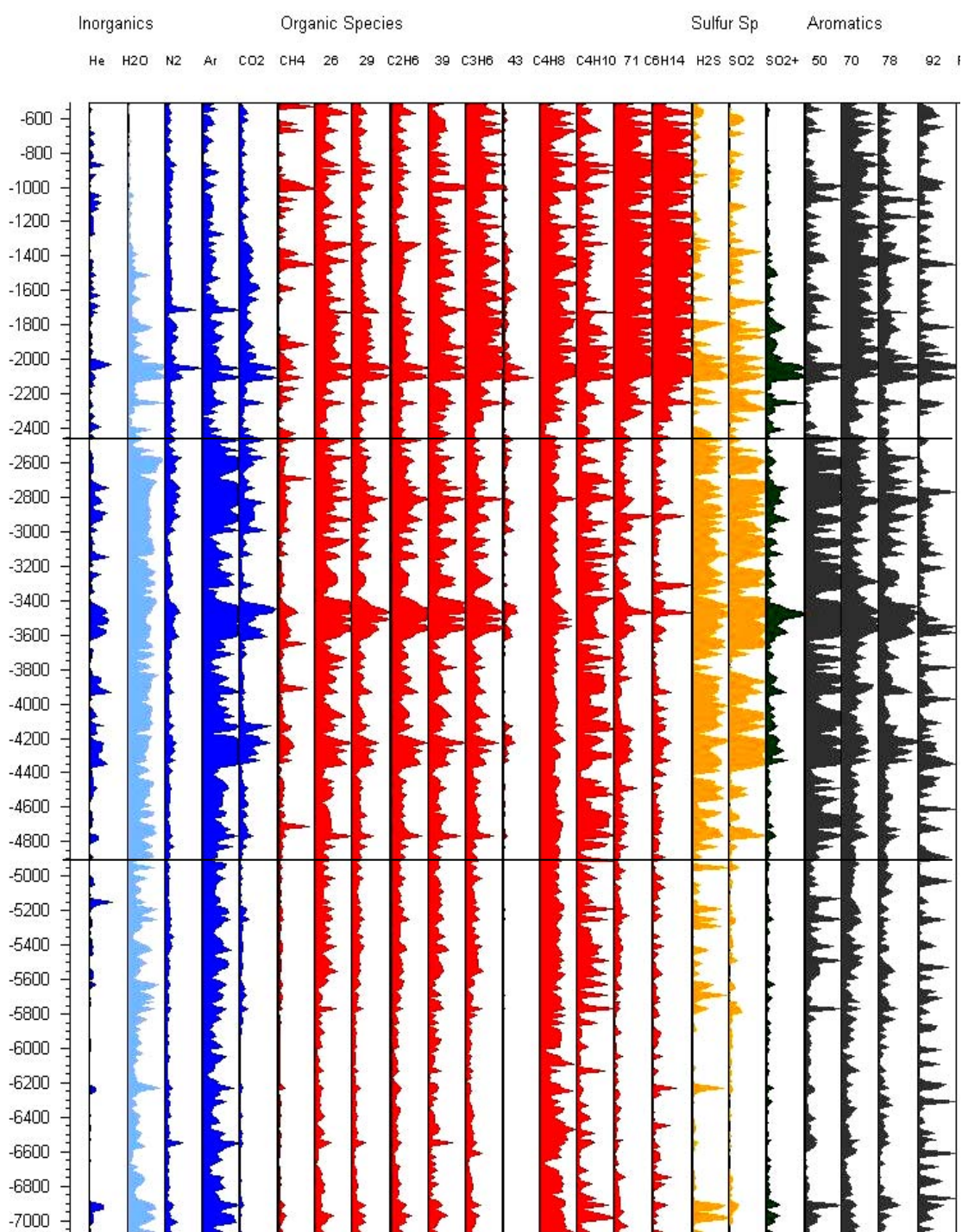


Figure 2: Analysis of Coso borehole 15A-17 that shows the intensity of the principal mass peaks plotted versus depth in feet. Columns are labelled where space permits with the species represented by the column below; data for mass peak 18 is labelled H<sub>2</sub>O, the column for mass peak 44 is labelled CO<sub>2</sub>, etc. Note that mass 43, which is a strong secondary peak for propane, is mostly blank.



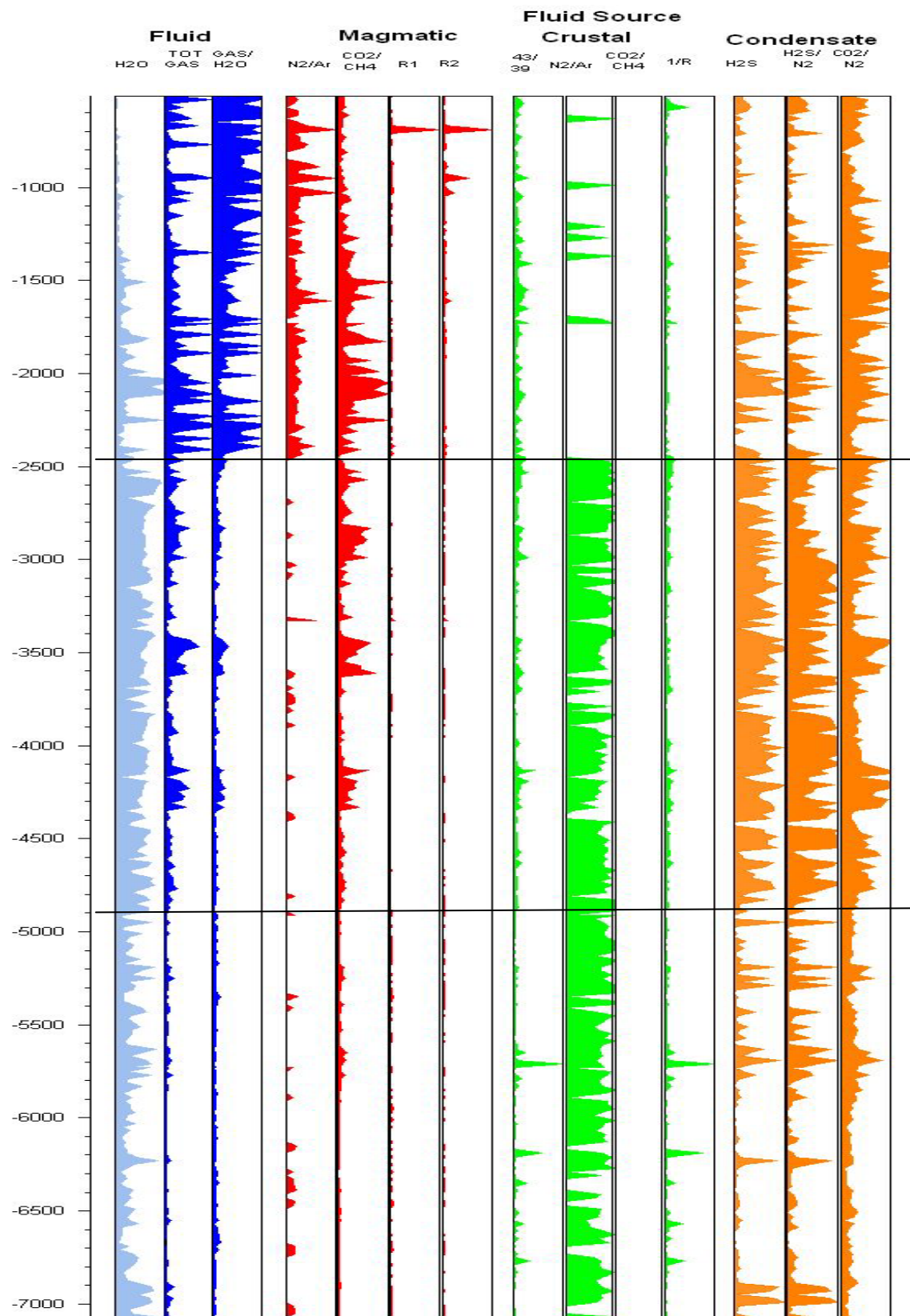


Figure 3: Analysis of Coso bore hole 15A-17 showing the relative intensity of gas ratios and species used to interpret fluid source. R1 and R2 are explained in the text.

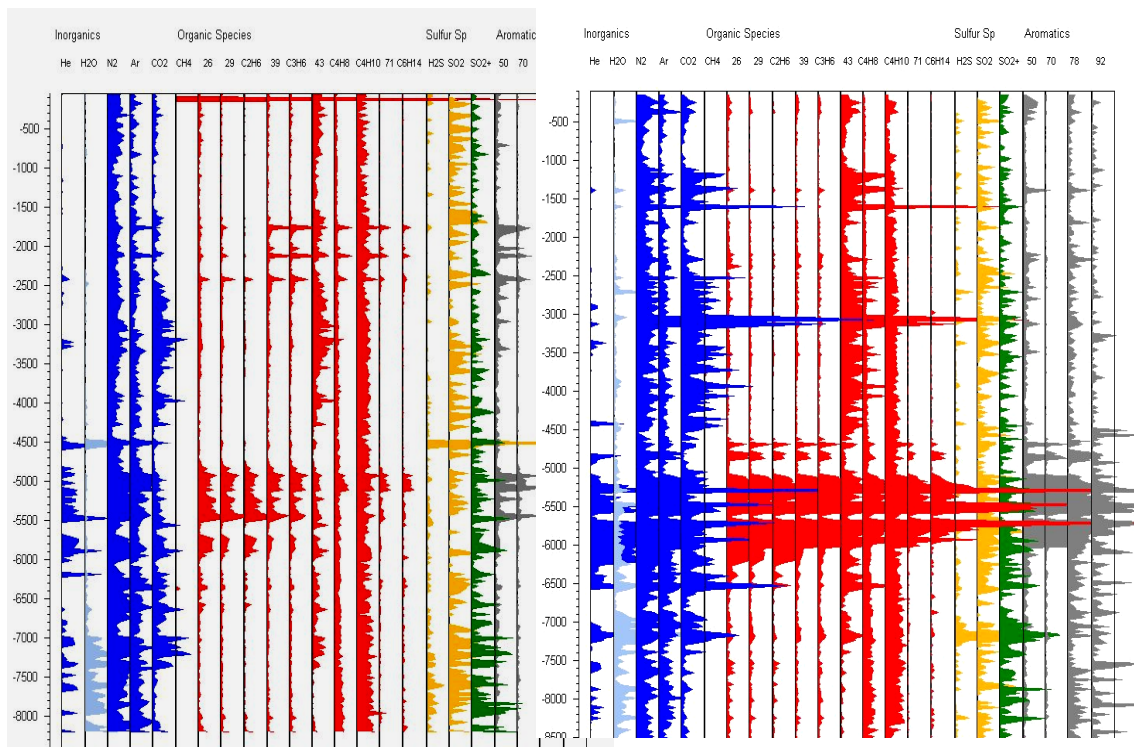


Figure 4: Analyses of Beowawe, NV wells. Analysis on the right is the production well 77-13 drilled in 1984. The analysis on the right is the new hole drilled in 2006. The Basin and Range fault at 5,000 to 5,500 ft is evident in well 77-13 that appears to be wide fracture zone. Borehole 53-13 must cut the same structure at a slightly greater depth.

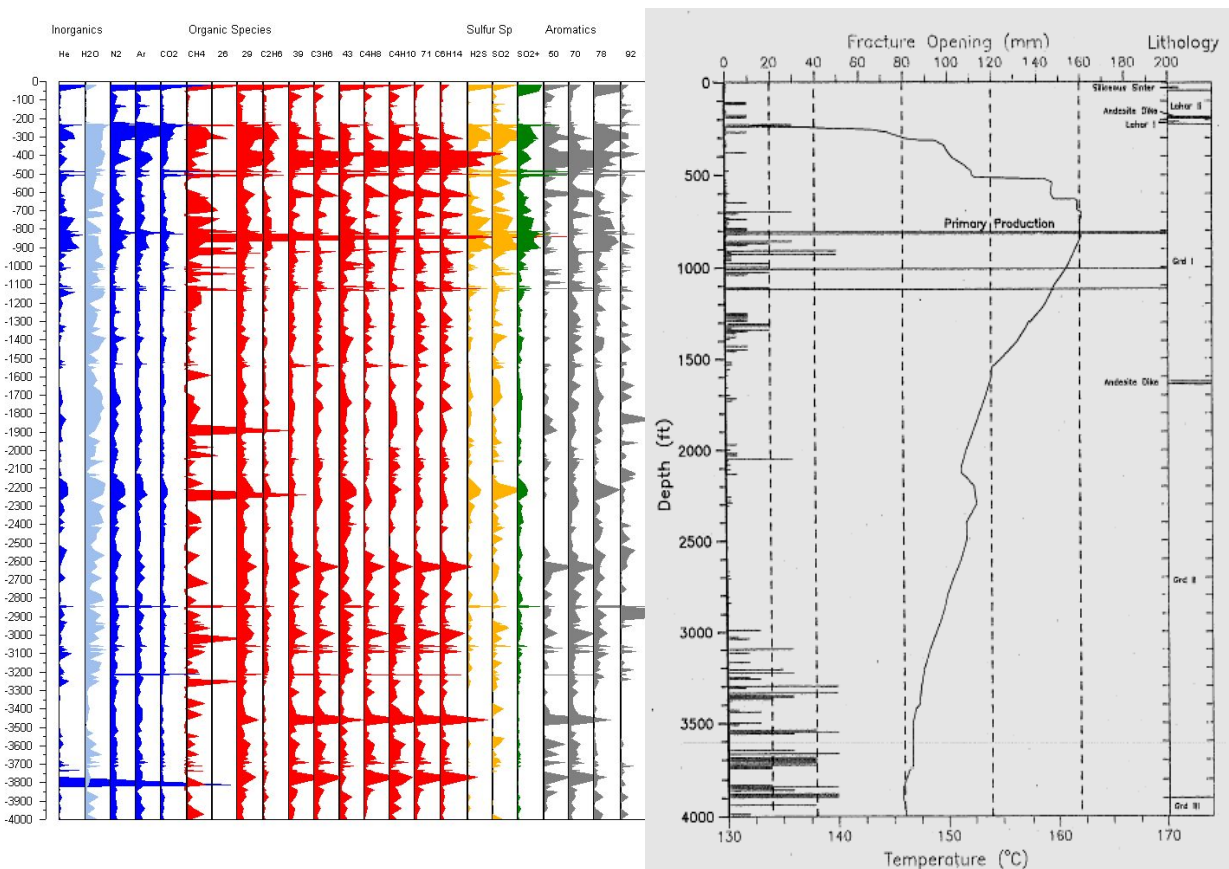


Figure 5: FIS log (right) and temperature and fracture fracture log for Steamboat Springs Well 87-29. background peak in mass spectrometers, or it maybe from air trapped in drill chip fractures.