Final Report for the Project Entitled
Creation of an Enhanced Geothermal System through
Hydraulic and Thermal Stimulation

DE-FC07-01ID14186

August 15, 2001 through June 15, 2012

Peter Rose, Principal Investigator
Energy and Geoscience Institute at the University of Utah
Executive Summary

This report describes a 10-year DOE-funded project to design, characterize and create an Engineered Geothermal System (EGS) through a combination of hydraulic, thermal and chemical stimulation techniques. Volume 1 describes a four-year Phase 1 campaign, which focused on the east compartment of the Coso geothermal field. It includes a description of the geomechanical, geophysical, hydraulic, and geochemical studies that were conducted to characterize the reservoir in anticipation of the hydraulic stimulation experiment. Phase 1 ended prematurely when the drill bit intersected a very permeable fault zone during the redrilling of target stimulation well 34-9RD2. A hydraulic stimulation was inadvertently achieved, however, since the flow of drill mud from the well into the formation created an earthquake swarm near the wellbore that was recorded, located, analyzed and interpreted by project seismologists.

Upon completion of Phase 1, the project shifted focus to a new target well, which was located within the southwest compartment of the Coso geothermal field. Volume 2 describes the Phase 2 studies on the geomechanical, geophysical, hydraulic, and geochemical aspects of the reservoir in and around target-stimulation well 46A-19RD, which is the deepest and hottest well ever drilled at Coso. Its total measured depth exceeding 12,000 ft. It spite of its great depth, this well is largely impermeable below a depth of about 9,000 ft, thus providing an excellent target for stimulation. In order to prepare 46A-19RD for stimulation, however, it was necessary to pull the slotted liner. This proved to be unachievable under the budget allocated by the Coso Operating Company partners, and this aspect of the project was abandoned, ending the program at Coso.

The program then shifted to the EGS project at Desert Peak, which had a goal similar to the one at Coso of creating an EGS on the periphery of an existing geothermal reservoir. Volume 3 describes the activities that the Coso team contributed to the Desert Peak project, focusing largely on a geomechanical investigation of the Desert Peak reservoir, tracer testing between injectors 21-2 and 22-22 and the field’s main producers, and the chemical stimulation of target well 27-15.
Volume 1

Final Report for the Portion of the Project Focused on the East Compartment of the Coso Geothermal Field

April, 2006

Creation of an Enhanced Geothermal System through Hydraulic and Thermal Stimulation

DE-FC07-01ID14186

Peter Rose¹, Principal Investigator; Steve Hickman⁴, Co-Principal Investigator; Jess McCulloch³, Co-Principal Investigator; Nick Davatzes⁴, Joseph M. Moore¹, Katie Kovac¹, Mike Adams¹, Mike Mella¹, Phil Wannamaker¹, Bruce Julian⁴, Gillian Foulger⁴, Dan Swenson⁵, Shekhar Gosavi⁵, Ashish Bhat⁵, Keith Richards-Dinger⁶, Frank Monastero⁶, Ralph Weidler⁷, Stefan Baisch⁷, Ahmad Ghassemi⁸, Thomas Kohl⁹, and Thomas Megel⁹

¹EGI, University of Utah
³Coso Operating Company
⁴U.S. Geological Survey
⁵Kansas State University
⁶GPO, Naval Air Weapons Station
⁷Q-con
⁸University of North Dakota
⁹Geowatt
Table of Contents

INTRODUCTION ........................................................................................................................................5
EXECUTIVE SUMMARY ..........................................................................................................................6
FIELD EXPERIMENTS ..............................................................................................................................11
   Fracture and Stress Analysis (Steve Hickman, Nick Davatzes, and Judith Sheridan) ...............11
      Summary of results from structural and stress analysis ...........................................................11
      Faults and fractures of the Coso Geothermal Field and East Flank ......................................16
      Image data analysis for natural fractures and stress directions ..............................................18
         Natural fractures visible in image logs of well 38C-9 ............................................................21
         Measurements of stress orientations from borehole image logs .........................................24
      Direct measurements of East Flank stress magnitudes ............................................................30
         Hydraulic fracturing stress magnitudes in well 38C-9 ............................................................31
         Hydraulic fracturing stress magnitudes in well 34-9RD2 ......................................................33
      Summary of hydraulic fracturing experiments .......................................................................34
PETROLOGY AND PETROGRAPHY (Katie Kovac and Joe Moore) ........................................37
   Background and Objectives .............................................................................................................37
   Petrology and Petrography of Well 38C-9/38C-9ST ..................................................................38
   Petrology and Petrography of Well 34A-9 ....................................................................................42
   Petrology and Petrography of Well 34-9RD2 .............................................................................46
   Fluid Inclusion Studies ...................................................................................................................48
   X-Ray Diffraction Studies ..............................................................................................................53
   Thermal Modeling of the Coso East Flank Compartment ...........................................................55
   References ......................................................................................................................................59
MICROSEISMS (Bruce Julian and Gillian Foulger) .................................................................60
   Background and Objectives .............................................................................................................60
   Microearthquake Monitoring ........................................................................................................61
      Permanent U.S. Navy seismometer network .............................................................................61
      Portable network .........................................................................................................................64
   Microearthquake Hypocenter Location .......................................................................................69
   Time-Dependent Seismic Tomography .......................................................................................72
      Acquisition and selection of initial data ....................................................................................72
      Inversion for best one-dimensional structure .........................................................................76
      Inversion for best three-dimensional structure .......................................................................81
      Summary of time-dependent tomography results ..................................................................88
   Earthquake Moment Tensors .......................................................................................................89
      Objectives of moment tensor analysis .....................................................................................89
      Sensor polarities and orientations ..............................................................................................90
      Results .......................................................................................................................................94
   The EGS Experiment in Well 34-9RD2: Integrated Interpretation .............................................97
      Background .................................................................................................................................97
      History of the injection test ........................................................................................................98
      Relative relocation results ..........................................................................................................100
      Moment tensor results ..............................................................................................................101
      Summary ....................................................................................................................................105
   Software Development ................................................................................................................107
      Earthquake source-mechanism determination .........................................................................107
      Three-dimensional visualization ..............................................................................................109
      Major programs written or significantly modified to date .......................................................111
   Publications and presentations ...................................................................................................113
   References ......................................................................................................................................113
MAGNETOTELLURICS (Phil Wannamaker) ...............................................................................114
   Background and objectives ........................................................................................................114
   Accomplishments ........................................................................................................................115
Coupled simulator compared with the deliverability model in TOUGH2 .......................................................... 194
Simulation of fluid flow in a sample well at East Flank .................................................................................. 195
Simulation of fluid flow with a coupled TOUGH2-HOLA simulator .............................................................. 198

T2STR .................................................................................................................................................................. 201
Loose backward coupling ................................................................................................................................. 201
Fully coupled implementation ......................................................................................................................... 203
Verification of fully coupled implementation ............................................................................................... 207
Modeling of fractured rock mass .................................................................................................................. 219
Five spot example ............................................................................................................................................ 227

References ......................................................................................................................................................... 233

Effects of Cold Water Injection on Fracture Aperture and Injection Pressure (Ahmad Ghassemi) .................. 234

Background and Objectives ............................................................................................................................ 234
Injection/Extraction for an Arbitrarily Shaped Fracture ............................................................................... 234
1.0 Introduction

The Coso geothermal field is an excellent setting for testing Enhanced Geothermal System (EGS) concepts. Fluid temperatures exceeding 350°C have been measured at depths less than 10,000 ft and the reservoir is both highly fractured and tectonically stressed. However, some of the wells within the reservoir are relatively impermeable. High rock temperatures, a high degree of fracturing, high tectonic stresses and low permeability are the qualities that define an ideal candidate-EGS reservoir. We have therefore assembled a team of capable scientists and engineers for the purpose of developing and evaluating an approach for the creation of an EGS within the Coso reservoir. In addition, the Navy Geothermal Program Office is providing valuable data from a regional Coso seismic survey and a localized east flank microseismic study.

Key to the creation of an EGS is an understanding of the relationship among natural fracture distribution, fluid flow, and the ambient tectonic stresses that exist within the resource. Once these relationships are determined, if is possible to design a hydraulic and thermal stimulation of a candidate injection well as the first step in the creation of a heat exchanger at depth. The success of the experiment can then be quantified through hydraulic, microseismic, geomechanical, and geochemical measurements. From the lessons learned at Coso, it will be possible to design and create an EGS wherever appropriate tectonic, thermal and hydraulic conditions exist, thereby allowing geothermal operators to greatly extend their developmental reach beyond the relatively few known geothermal resources.

The objective of the EGS project at Coso is to stimulate one or more low permeability injection wells through a combination of hydraulic, thermal and chemical methods and to hydraulically connect the well(s) to at least one production well. Thus, the objective is not only to design and demonstrate an EGS on the periphery of an existing geothermal reservoir, but to understand the processes that control permeability enhancement. The primary analytical tools used include borehole logs for imaging fractures and determining regional stresses, petrographic and petrologic analyses of borehole cuttings, petrophysical measurements of core samples, geophysical methods including microseismology and magnetotelluric (MT) studies, structural analysis, fluid-flow modeling, and geochemical modeling. Lessons learned at Coso will make it possible to design and create an EGS wherever appropriate tectonic, thermal and hydraulic conditions exist, thereby allowing geothermal operators to greatly extend their developmental reach beyond the relatively few naturally occurring hydrothermal resources.

The initial focus for the EGS project at Coso was the east margin of the field where injection wells had been drilled into high-temperature, low-permeability rock in close proximity to some of the field’s most productive wells (see Figure 1.0). These wells of marginal injectivity provided excellent laboratories for studying hydraulic stimulation techniques that, if proven successful, could be of great utility both for EGS activities but for conventional geothermal programs as well. Unfortunately, a suitable target for hydraulic stimulation experiments was never identified within the East Flank section of the reservoir. Nevertheless, well 34A-9, which had previously been stimulated under low-wellhead pressures, was shown through recent circulation testing to have been transformed into an excellent injection well.
Figure 1.0. Plan view of the Coso field showing the East Flank compartment. The trajectories of the production wells are shown in red, whereas the injection wells are colored blue. Abandoned wells are in green.

1.1 Executive Summary

This report describes the EGS R&D program on the East Flank compartment of the Coso geothermal field during the first four years of the Coso/EGS cooperative agreement. Section 2 describes the tools and methods developed and demonstrated for the East Flank field experiments, including wellbore image analysis, fracture and stress analysis, petrology and petrography, microseisimics, magnetotellurics, hydraulic stimulation under low-wellhead pressures, and circulation testing. Section 3 describes the various models that were developed and calibrated for simulating the geomechanical, geochemical, and fluid flow processes involved in the design and evaluation of an EGS reservoir.
In the East Flank of the Coso Geothermal Field, integrating borehole measurements of stress and maps of modern faulting with detailed examination of fault rocks reveals how fault zone evolution and loading interact with fluid flow. Active faults trending NNW-SSE to NNE-SSW that offset Quaternary to Holocene sediments are well oriented for normal slip in the current stress field, where the mean $S_{hmin}$ orientation is $108° \pm 24°$ in a transitional strike-slip to normal faulting stress regime. These structures bound regions of intense micro-seismicity and are complexly associated with surface hydrothermal activity. WNW-ESE trending faults are also associated with distinct regions of enhanced seismicity but are only associated with surface hydrothermal activity where they intersect more northerly trending normal faults. The WNW-ESE trending faults show no evidence for Quaternary slip at the surface and are poorly oriented in the modern stress field. These results together with stress magnitudes measured in the East Flank of the field suggest that the most productive portions of the Coso geothermal field are in stress environments conducive to normal faulting. Analysis of fractures seen in image logs from East Flank wells using our stress orientations and magnitudes indicates that increasing fluid pressure within the reservoir by 500 psi or more would induce shear failure on existing fractures, thereby increasing reservoir permeability. Analysis of focal mechanisms for the region surrounding the 46A-19RD well suggests a stress environment similar to that seen in the East Flank.

In detail, the mineralogy and microstructure of fault rock obtained from core and surface outcrops reveals three fault rock types: (1) Fault rock consisting of zeolites, amorphous silica, and kaolinite that contains large connected pores, dilatant brittle fractures, and dissolution textures. (2) Fault rock consisting of foliated layers of chlorite and illite-smectite separated by slip surfaces, which accommodates slip through ductile shearing and folding. (3) Fault rock consisting of poorly sorted angular grains, characterized by large variations in grain packing (pore size), and crack-seal textures resulting from repetitive brittle failure, dilation, and precipitation of quartz or calcite. Clay-rich fault rocks mitigate dilation during slip, produce frictionally weak fault zones with low permeability whereas fault zones healed by calcite or silica preserve the frictional strength of the fault and promote recurrent brittle failure that regenerates permeability. At Coso, these different fault rocks are respectively associated with a high permeability upper boiling zone in the geothermal system, a conductively heated “caprock” at moderate to shallow depth associated with low permeability, and a deeper convectively heated region associated with enhanced permeability. Thus, which minerals form, and the rates at which they grow is also a key element in targeting regions for permeability enhancement as part of an EGS experiment. In 46A-19RD, cuttings analysis indicates only minor hydrothermal alteration at reservoir depths, indicating that dilatant brittle failure should dominate during injection-induced reservoir stimulation, thereby increasing permeability. The anticipated mineralogy at depth together with the favorable stress environment inferred from focal mechanism inversions in this area suggest that 46A-19RD should be an ideal candidate for EGS reservoir stimulation.

Petrographic and petrologic studies, as presented in Section 2.2, were implemented to 1) construct the overall geologic framework of the East Flank; 2) document and characterize geothermal and older fluid flow paths; and 3) aid in the interpretation of FMS and borehole televiewer logs. Cuttings and thin sections from many East Flank wells were studied. Studies of these samples provided data including: rock type and mineralogy, relative amount of overall...
alteration, relative amounts and mineralogy of the veining, the presence of open-space fillings, and presence of brecciation. In addition, fluid inclusion and x-ray diffraction studies were implemented to assist in separating different thermal events, and thus in assembling the thermal history of the system.

In this work, the dominant host rock lithologies were characterized, a comprehensive paragenetic sequence of the vein minerals was created, and a basic geologic model of the East Flank was constructed. Evidence of several episodes of hydrothermal activity has been preserved in the reservoir rocks, and fluid inclusion data (previous quarterlies; Kovac et al., 2005; Adams et al., 2000) as well as other data suggest that temperatures beneath the East Flank of the field are rising (Kovac et al., 2005; Bishop and Bird, 1987; Lutz et. al, 1999; Manley and Bacon, 2000). These investigations have contributed to a greater understanding of the geothermal system, the reservoir lithology of the East Flank, and the interplay between the two.

The aim of microseismicity program (Section 2.3) is to use microearthquakes to study processes occurring in the Coso geothermal area, both during normal operations and during EGS injection experiments. Data were obtained from two seismometer networks, the US Navy’s permanent telemetered borehole network and a supplemental network of portable surface seismometers deployed to optimize coverage of particular injection experiments. The Navy network is of high quality, but still required significant work in preparation for EGS experiments. The orientations of the horizontal sensors were not known, and have now been determined from seismic-wave measurements. In addition, a few borehole sensors that had malfunctioned over the years have been replaced with surface sensors. We initially designed the portable network using three-dimensional seismic ray tracing to account for detailed structure in the area in order to provide optimal coverage of well 34-9RD2.

To provide rapid information on earthquake occurrence and location, we are operating an EarthWorm/EarlyBird computer system at China Lake to monitor telemetered data from the permanent Navy network in real time. Information on the geometry of failure regions, provided by high-resolution hypocenter locations, are valuable supplements to seismic source mechanisms for diagnosing physical processes at work (for example shear faulting vs. tensile cracking). We have optimized existing algorithms for measuring relative arrival times of seismic waves and have used them to determine high-resolution relative hypocenter locations to facilitate their application to injection experiments.

Applying local-earthquake seismic tomography to data from the permanent Navy seismometer network, we have obtained a new three dimensional model of seismic wave speeds in the geothermal area and have studied possible changes in wave speeds between 1996 and 2004. The three-dimensional model is valuable for such things as designing portable seismometer networks, and determining hypocenter locations. Temporal variations detected are dominated by a decrease in the wave-speed ratio $V_P/V_S$ at shallow depth, reflecting primarily an increase of $V_S$ with respect to $V_P$. This change probably reflects of a decrease of pore-fluid pressure and/or the drying of argillaceous minerals.
Drilling in preparation for the injection experiment at well 34-9RD2 encountered a highly permeable zone on March 2, 2005, among whose effects was a swarm of microearthquakes that migrated upward, northward, and slightly eastward from near the bottom of the well. Most of the largest events occurred within a 2-minute interval. The seismic source mechanisms (moment tensors) during this short interval involve volume increases, and differ strongly and systematically from those of earlier and later microearthquakes. High-resolution hypocenter locations define a plane striking NNE (20°) and dipping steeply (75°) to the WNW (Fig. 5.3). This orientation, in combination with the moment tensors, identifies this plane as a locus of tensile failure.

Section 2.4 describes the magnetotelluric studies that were conducted with the objective of characterizing the East Flank electrical resistivity structure. A grid of 102 five-channel MT soundings plus a dense MT array profile of 52 bipoles was acquired over the Coso east flank to define geometry, bounds and controlling structures in the existing production area and to help select wells for EGS stimulation. This work was funded by the U.S. Dept. of Energy/GTP and the Dept of Navy/GPO. High quality data were obtained under uniquely difficult ambient noise conditions through use of novel ultra-distant remote referencing procedures. Two-dimensional inversion of the dense array profile by Co-I Wannamaker revealed a steeply west-dipping low-resistivity zone beneath the east flank interpreted to correspond with high fracture porosity and permeability of the main production zone. Ongoing 2-D and 3-D inversion efforts by G. Newman and coworkers at LBNL in conjunction with Wannamaker are confirming this structure and defining its N-S bounds. The northern bound appears to lie coincident with the lineament joining Coso Hot Springs to just north of Devil’s Kitchen, while the southern bound lies just south of well 86-17. These images should provide substantial value in concentrating future exploration and development efforts in the Coso field.

As described in Section 2.5, a hydraulic stimulation experiment was successfully conducted in East Flank well 34A-9 in 1993/1994. A circulation test, complete with microseismicity monitoring, was conducted in 2004 as part of this program in order to determine the degree of connectivity of 34A-9 to surrounding production wells. This test demonstrated that the stimulation of a tight injection using low volumes of injectate under very low wellhead pressures (less than 100 psi) can have a very strong positive effect on reservoir permeability.

Section 2.6 describes the design and preparation of the field experiment involving injection well 34-9RD2. The original plan was to reline and deepen the well followed by the hydraulic-stimulation of the newly drilled section. Unfortunately, upon redrilling a very permeable set of fractures was intersected and the hydraulic stimulation experiment had to be redirected towards a different well-target. Nevertheless, the experiment provided invaluable understanding of the fracturing and stresses within the Coso field as well as an excellent dry run for the microseismicity monitoring program. Likewise, a new vapor-phase tracer was demonstrated as part of the subsequent circulation test.

In Section 3.2 on Geochemical Monitoring, it is shown that artificial tracers can be used to monitor changes in permeability and to determine presage boiling within a producing field. Also in this section, a reactive-transport modeling study was conducted in order to predict the extent of mineral dissolution and/or precipitation on permeability. Injection water chemistry can have a
tremendous impact on the success or failure of an injection operation. The chemical interactions between host rocks and fluids, by causing the dissolution and precipitation of minerals, can either enhance or destroy permeability and porosity in the area of interest. Reactive chemical transport simulation of injection should be a useful tool aiding in decisions relating to reservoir management. To assess these interactions and their potential effects on the Coso Enhanced Geothermal Systems (EGS) experiment, modeling efforts using the program TOUGHREACT have been initiated. TOUGHREACT is a numerical simulation program for chemically reactive non-isothermal flows of multiphase fluids in porous and fractured media.

The techniques developed can be applied to any injection well of interest on the East Flank. The initial model was created to simulate injection into well 34-9RD2. Host rock and fracture mineralogies were taken directly from petrographic studies. Sensitivity studies were performed to examine the effects of changes in pH, temperature, and composition of injection fluid. This model generally agrees with post-injection observations from the field. Significant amorphous silica, and minor amounts of calcite, quartz, and anhydrite are shown to precipitate while only calcite shows dissolution in the fractures. Both the model results and field experience suggest that amorphous silica precipitation is an important factor in the performance of a stimulation experiment at Coso.

In Section 3.3, the code HEX-S is used to simulate the development of fracture permeability using a combination of stochastic and deterministic fractures. Input for the code was created using data from the East Flank well 34-9RD2.

The objective of the Kansas State University team (Section 3.4) was to provide coupled thermal-hydraulic-mechanical analysis tools that enable quantitative understanding and prediction of thermal effects on flow in the reservoir. The goal was to apply these tools to the analysis of thermal stimulation of wells in the reservoir. Using a combination of analysis and testing, the goal was to clearly identify the conditions under which thermal stimulation is significant and to predict the magnitude of the change resulting from such stimulation.

To accomplish this, it was decided to incorporate stress coupling with the TOUGH2 code. TOUGH2 is a program that is used to calculate multi-phase, multi-component, non-isothermal flow in porous media. It uses a modified dual-permeability approach to represent flow in fractured media. The strengths of the code include: use of the integral finite difference approach which can accommodate general geometry, implementation of many different equations of state for different component mixtures, and coupled heat transfer.

A dual mesh approach was used to add stress capability to TOUGH2. The node at the center of the integral finite difference cell becomes a corner node in a finite element mesh used for the stress calculation. This allows an elegant way to use the integrated finite difference method for the part of the solution it is best suited for (mass and heat transport) and a finite difference method for the part of the solution it is best suited for (deformation and stress).

A second part of the implementation was to couple a well-bore simulator (HOLA) with the flow calculation. This is needed for simulation of the Coso reservoir, where there can be considerable
local draw-down near the wells. In the end, the software coupling was completed and several verification problems run.

In Section 3.5, a 3D boundary element model for heat extraction/thermal stress was coupled with a 3D elastic displacement discontinuity method to investigate the fracture opening and slip in response to pressure and cooling of the rock under a given in-situ stress field. Using this approach, the effects of each mechanism on rock stress and fracture slip was estimated. The results of displacement analysis have indicated that under typical field conditions, a substantial increase in fracture slip can be observed when thermal stresses are taken into account. The amount of slip would depend on the rock properties, fracture orientation, in-situ stress, pressure, injection rate, and injection temperature.

For conditions of the Coso Geothermal Field, the predicted slip is on the order of several cm’s for a few months of injection/extraction at the rates proposed. The results have shown that the fracture slip causes a substantial fracture permeability enhancement due to increasing fracture aperture.

2.0 Field Experiments

2.1 Fracture and Stress Analysis (Steve Hickman, Nick Davatzes, and Judith Sheridan)

2.1.1 Summary of results from structural and stress analysis

The Coso geothermal field is located along the western edge of the Eastern California Shear Zone (Figure 1.1), subjected to both strike-slip and normal faulting. The field is situated in diorite, quartz diorite, granodiorite, and minor basalt above a partially molten magma body at depths as shallow as 4-5 km (Wicks et al., 2001; Monastero et al., 2005; Unruh and Hauksson, 2003; Manley and Bacon, 2001). These depths correspond to a cut-off in seismicity that is presumed to represent the brittle-ductile transition (Figure 1.2) (Monastero et al., 2005). At the surface, intrusion of the magma body has resulted in Pliocene to recent rhyolites domes and basalt flows (Duffield et al., 1980, Figure 1a). Unruh et al. (2002) and Monastero et al (2005) suggest that Coso lies within the right (releasing) step between the right lateral Little Lake fault zone to the SW and the Wild Horse Mesa fault to the NE which are associated with strike-slip focal mechanisms. This zone accommodates 6.5±0.7 mm/year dextral shearing (McCluskey et al., 2001; Monastero et al., 2005).
Figure 1.1: DEM image of the Southwestern United States and tectonic map of the Eastern California Shear Zone. After Unruh (2002).
Barton et al. (1995, 1998) have shown that optimally oriented, critically stressed fractures control permeability in areas of active tectonics. This suggests that critically stressed fracture sets are likely to be responsible for the majority of the geothermal production in the Coso Geothermal Field. A detailed analysis was required in order to develop a geomechanical model of the reservoir, to determine which fractures are optimally oriented and critically stressed for shear failure, and determine their role in reservoir permeability. The geomechanical model includes pore pressure (P_p), uniaxial compressive rock strength (C_0), and the magnitudes and orientations of the principal stresses including the maximum horizontal stress (S_{max}), the minimum horizontal stress (S_{min}), and the vertical stress (S_V). These are derived from in situ pore pressure measurements, laboratory rock strength tests, wireline log data, hydraulic fracturing (minifrac) test results, and observations of wellbore failure visible in image logs. Only through fracture and wellbore failure analyses of image data, correlated petrographic analyses, and identifying critically stressed fault orientations and fault orientations in fluid flow intervals can we then understand the effects of subsequent stimulation experiments on fracture permeability. The results of these studies are summarized in the following paragraphs, with detailed discussion later in this report of the data in section 2.1.3 and the analysis in section 3.1.

In this study we integrate measurements of stress and maps of modern faulting with detailed examination of fault rocks to investigate fault zone evolution and fluid flow in the fault-hosted, fracture-dominated geothermal system contained in granitic rocks of the Coso Geothermal Field, CA. Vertically averaged stress orientations measured from boreholes across the field are fairly uniform and are consistent with focal mechanism inversions of earthquake clusters for stress and incremental strain. Active faults trending NNW-SSE to NNE-SSW are well oriented for normal slip in the current stress field, where the mean S_{min} orientation is 108° ± 24° in a transitional strike-slip to normal faulting stress regime. These structures bound regions of intense microseismicity and are complexly associated with surface hydrothermal activity. Another group of faults trending WNW-ESE are also associated with distinct regions of enhanced seismicity but are only coincide with surface hydrothermal activity where they intersect more northerly trending normal faults. These faults show no evidence for Quaternary slip at the surface and are poorly oriented in the modern stress field. These results together with stress magnitudes measured in the East Flank of the field suggest that the most productive portions of the Coso geothermal field are in stress environments most conducive to normal faulting. In addition, significant horizontal principal stress rotations are recorded by drilling-induced structures in borehole image logs. These variations in the azimuth of induced structures suggest local stress heterogeneity induced by active fault slip and are consistent with the high rates of seismicity observed in the geothermal field.
Normal faults divide the geothermal field into three main geologic sub-regions (Figure 1.3): the Main Field, a central spine of exposed bedrock which includes the East Flank region, and Coso Wash. The Main Field is associated with high seismicity rates, high temperatures (>640°F at <10,000 ft depth), and Quaternary rhyolite domes (Bishop and Bird, 1987). The spine of exposed bedrock extends north to south. Its intensely normal faulted eastern margin hosts the East Flank reservoir. With the exception of the East Flank region which is associated with high temperatures and seismicity, the central region is largely aseismic and cool (Lutz et al., 1996). The East Flank also stands out from the rest of this area because of the high normal fault density roughly located on the footwall side of a step between two Coso Wash normal fault segments. Coso Wash is a series of sub-basins associated with segments of the Coso Wash fault and experiences the least seismicity and low temperatures (Davatzes and Hickman, 2005b). The intersection of the N to NNE normal faults with the WNW faults dissects all three regions of the geothermal field into rhombohedral fault-bounded blocks.

Figure 1.3: Sub-regions of the Coso Geothermal Area are distinguished by fluid temperature, seismicity, and heat flow and bounded by normal faults and strike-slip faults.
A faulting regime that is transition from normal-slip to strike-slip in the East Flank of the field is suggested by hydraulic fracturing stress tests that measure $S_{hmin}$ and constraints on $S_{Hmax}$ from borehole breakouts and rock strength. Holocene sediments offset by modern basin-bounding normal faults suggest that these normal faults play a major role the modern deformation field. These measurements are also consistent with inversions of seismicity in the upper 0.5 to 2.5 km of the field, which indicate that the East Flank and southern portion of the Main Field are actively extending. Thus, these results suggest that well 46A-19RD is well situated for EGS stimulation through injection-induced shear failure to enhance permeability in a hot but low permeability portion of the Main Field. Hydraulic fracturing stress test results show that the magnitude of $S_{hmin}$ is relatively low and slightly above that predicted for normal faulting failure. Borehole failure analysis of well 38C-9 (which are equally applicable to well 34-9RD2) and simple frictional faulting theory indicate that this value of $S_{hmin}$ and approximate bounds on $S_{Hmax}$ are consistent with crustal strength being controlled by normal to strike-slip faulting. Fracture failure analyses using this improved Coso stress model indicate that normal faulting failure will not occur under ambient conditions, but can be induced through increases in reservoir pressure in excess of 500 psi. Strike-slip failure can potentially be induced by lesser increases in reservoir pressure but is difficult to evaluate because of poor constraints on $S_{Hmax}$.

Outcrop and hand-sample scale mapping, XRD analysis, and SEM secondary electron images of fault gouge and slip surfaces at different stages of development (estimated shear strain) are used to investigate the processes responsible for the development and physical properties of these distinct fault rocks. In each type of fault rock, mineral dissolution and re-precipitation in conjunction with the amount and geometry of porosity changes induced by dilation or compaction are the key controls on fault rock development. In addition, at the contacts between slip surfaces, abrasion and resulting comminution appear to influence grain size, sorting, and packing. Macroscopically, we expect the frictional strength of these characteristic fault rocks to differ because the processes that accommodate deformation depend strongly on mineralogy. Frictional strength of quartz-dominated fault rocks in the near surface and in the reservoir should be greater (~0.6) than that in the clay-dominated cap rock (~0.2-0.4). Similarly, permeability should be much lower in foliated clay-rich fault rocks than in quartz-rich fault rocks as evidenced by larger, more connected pores imaged in quartz-rich gouge. Which minerals form, and the rates at which they grow is also a key element in determining variations in the magnitude and anisotropy of fault zone properties at Coso. Mineral stability is a function of loading, strain rate, temperature, and fluid flow conditions. Consequently, we suggest that the development of fault-zone properties depends on the feedback between deformation, resulting changes in permeability, and large-scale fluid flow leading to dissolution/precipitation of minerals in the fault rock and adjacent host rock (Figure 1.4). The implication for Coso is that chemical alteration of otherwise low-porosity crystalline rocks appears to determine the distribution and temporal evolution of permeability in the actively deforming fracture network at small to moderate scales as well as along major, reservoir-penetrating fault zones.
**Figure 1.4:** Schematic showing how cycles of deformation and chemical reactions along faults can control the evolution of fault zone strength, frictional behavior, and hydrologic properties. This geomechanical model provides a first step in studying the mechanical interactions and permeability of fault zones, their natural evolution, and their response to engineered stimulation. In addition, this model is a critical element of the stimulation strategy that will be applied to Enhanced Geothermal Systems (EGS) well 46A-19RD in the southwest portion of the geothermal field in 2006. This next phase of the analysis will integrate our newly developed understanding of the fault rock properties, the stress state, and characteristics of the earthquakes that occur within and adjacent to the geothermal field.

### 2.1.2 Faults and fractures of the Coso Geothermal Field and East Flank

In this section we attempt to integrate existing fault maps and observations with our own field observations within the active geothermal field to define the fault geometry. However, for brevity we do not present an exhaustive discussion of the rich data set available nor do we discuss conditions at the boundary of the geothermal field. In addition, the full three-dimensional geometry of these faults and their mechanical relationships are subjects of on-going research.

Faults within the CGF can be broken into two distinct groups based on their geometry and inferred style of faulting. One group consists of WNW trending and minor NE trending faults (Figure 2.1a). Many of these faults extend well outside the field and form prominent lineaments. These faults are interpreted as dextral and sinistral strike-slip faults respectively by Duffield *et al.* (1980) and Roquemore (1984). Activity on these faults is not entirely clear at this time. They are exposed most often in bedrock and do not clearly offset any Quaternary sediment, but are associated with diffuse micro-seismicity in the geothermal field and with some minor geomorphic expression. The relationship of the diffuse cloud of seismicity to the faults is difficult to interpret at this time, but this problem may be solved by the efforts of the Navy.
Geothermal Program Office and the U.S. Geological Survey to more accurately relocate these earthquakes. At this time, we interpret these faults to be relatively inactive.

The other group consists of normal faults that dominantly trend N to NNE and dip both west and east (Figure 2.1a). The most prominent of these fault systems is the Coso Wash normal fault which coincides with the eastern margin of the geothermal field. It is composed of several en-echelon NNE-SSW trending segments variably connected by NW-trending, probably oblique-slip, faults. Normal faults appear to have been active in the Quaternary based on geomorphic expression (Angela Jayko, pers. comm. 2004), offset hydrothermal deposits (Hulen, 1978), and offset basalt flows (Figure 2.1a). A subset of this normal fault population also offsets Holocene basin sediments (Unruh and Streig, 2004), creates local sediment catchments, and is associated with seismicity (Figure 2.1b). Thus, we interpret these faults to be actively slipping.

The normal faults divide the geothermal field into three main geologic sub-regions (Figure 1.3): the Main Field, a central spine of exposed bedrock which includes the East Flank region, and Coso Wash. The Main Field is associated with high seismicity rates, high temperatures (>640°F at <10,000 ft depth), and Quaternary rhyolite domes (Bishop and Bird, 1987). The spine of exposed bedrock extends north to south. Its intensely normal faulted eastern margin hosts the East Flank reservoir. With the exception of the East Flank region which is associated with high temperatures and seismicity, the central region is largely aseismic and cool (Lutz et al., 1996). The East Flank also stands out from the rest of this area because of the high normal fault density roughly located on the footwall side of a step between two Coso Wash normal fault segments. Coso Wash is a series of sub-basins associated with segments of the Coso Wash fault and experiences the least seismicity and low temperatures (Davatzes and Hickman, 2005b). The intersection of the N to NNE normal faults with the WNW faults dissects all three regions of the geothermal field into rhombohedral fault-bounded blocks.
Figure 2.1: (a) Tectonic map of the east flank of the Coso geothermal field over shaded relief image of topography. Location of alteration, fumaroles, and steaming ground is based on new mapping and results from Hulen (1978), Duffield et al. (1980), Whitmarsh (1998a, b), Jayko (Personal communication, 2004), and work by Unruh and Streig (2004). (b) Minimum horizontal stress orientations inferred from borehole image logs from Geomechanics International (2003), Sheridan et al. (2003), Sheridan and Hickman (2004) and Davatzes and Hickman (2005a). Wells discussed in this paper are indicated, as are stresses and incremental strains inferred from clusters of seismicity from 1980 to 1995 (Feng and Lees, 1998) and 1980 to 1998 (Unruh et al., 2002). Both analysis combine data from the Southern California Seismic Network with the local seismic array at Coso maintained by the Navy Geothermal Program Office.

2.1.3 Image data analysis for natural fractures and stress directions

Electrical and acoustic image logging tools provide an invaluable opportunity to characterize the fracture populations that typically control fluid flow in geothermal systems. However, these tools detect fractures by measuring different properties of the borehole wall. Fractures interpreted from electrical image logs are identified by contrasts in conductivity between the fracture and the...
adjacent borehole wall. By contrast, fractures in acoustic image logs are associated with changes in borehole wall surface roughness or acoustic reflectivity. In both types of logs, fractures with the largest apparent apertures are often—but not always—observed to dominate subsurface fluid flow in geothermal fields (Barton et al., 1998; Sheridan and Hickman, 2004). Wells in the East Flank of the Coso Geothermal Field have been imaged using the ABI85 High Temperature Borehole Televiewer (ABI85), Formation Micro Imager (FMI), Hot Hole Formation Micro Scanner (FMS), and Electrical Micro-Imager (EMI).

Electrical image logs were obtained in wells 34-9RD2 and 58A-10 using the FMS tool (Figure 2.2a) that has been used extensively throughout the Coso Geothermal Field. Electrical image logs in wells 38A-9, 38B-9, 38C-9, and 83-16 were produced by some combination of FMS and either FMI or EMI tools. Electrical images are produced by placing pads with arrays of electrodes maintained at a constant electrical potential against the borehole wall, and measuring the current drop as the electrodes travel along the borehole wall (Figure 2.2a) (Ekstrom et al., 1987). Data from multiple electrodes are combined to produce electrical conductivity images. Because a current is being passed into the borehole wall, this technique actually measures the properties of a volume of rock within a few inches of the borehole wall. The azimuthal coverage of the image and its resolution is determined by the size and number of electrodes, their arrangement, the pad dimensions, and the borehole diameter. Resolution approaching 5 mm was attained in many wells with the FMS tool, and the image spanned about 40% of the borehole circumference within four equally spaced strips. The FMI and EMI tools provide greater, but still incomplete azimuthal coverage. Overall image quality is strongly related to pad contact and thus is sensitive to borehole shape and roughness, and to mud cake (Hearst et al., 2000). This tool can operate at temperatures up to 200°C for up to 1 hour, with longer operating times at lower temperatures.

The acoustic log used in this study was produced by a new state-of-the-art borehole televiewer (BHTV) built by Applied Logic Technologies (ALT) under joint funding from the Department of Energy and Navy Geothermal Program Office in collaboration with Sandia National Lab and the U.S. Geological Survey (Figure 2.2b photograph). The new BHTV is specifically designed for use in geothermal wells up to 300°C can operate at temperatures of 275°C for approximately 12 hours. This study combines results from two BHTV tools from ALT, the ABI85, which includes a combined temperature sensor, and the prototype.

Acoustic image logs are produced by bouncing an ultrasonic acoustic pulse from the borehole wall (Zemaneck et al., 1970) (Figure 2.2b). The tool uses a transducer that both emits and records the acoustic pulse. The travel time of the pulse from the transducer to the wall and back indicates the dimensions of the borehole and the relative position of the tool. The energy of the returning pulse, recorded as amplitude, is a function of the degree of scattering of the pulse due to the borehole shape and rugosity as well as the acoustic impedance contrast between the borehole fluid and wall. Complete azimuthal scans of the borehole wall are composed of 72, 144, or 288 acoustic pulses directed by a rotating mirror.

Each pulse has an optimal footprint of 5 to 7 mm. Two images are available for analysis: (1) two-way travel time (proportional to borehole radius and the fluid velocity) and (2) amplitude. Image quality is sensitive to borehole shape and tool position. Smooth, cylindrical boreholes
with a well-centered tool return maximum acoustic energy because of the resulting high incidence angle and low scattering of the acoustic beam. Departures from this ideal degrade the image quality. BHTV logs were collected in 58A-10 with vertical pixel dimensions of 5 to 7 mm and azimuthal pixel dimensions of 2.5°, about 3.5 mm. BHTV image logs were processed using two different programs: WellCad™ by ALT and Imager™ by Geomechanics International (GMI).

Figure 2.2: (a) Photograph of Schlumberger Hot Hole Formation Micro-Scanner (FMS) tool and cartoon of current transmitted into borehole wall modified from Ekstrom et al. (1987) used to create the micro-resistivity image of the borehole wall. (b) Photograph at the top depicts the acoustic head of the ABI85 Borehole Televiewer used at Coso. Below is a cartoon of the acoustic wave emitted by the transducer which is focused on the borehole wall by a spinning mirror. The
travel time of the pulse from the transducer to the borehole wall and back is measured as is the strength of the returning acoustic pulse. Some energy is scattered at the “window” by the slight acoustic impedance contrast between the oil in the tool, the “window” of the tool, and the fluid in the borehole.

For a detailed comparison of the differences in analyzing natural fracture populations from image logs obtained from resistivity versus acoustic image logging tools please refer to Appendix A.

2.1.3.1 Natural fractures visible in image logs of well 38C-9

Electric Micro Imager (EMI) data were acquired in two intervals in well 38C-9, from 690–3,726 feet measured depth (MD) and 5,881–9,408 feet MD. The EMI tool provides good data for detecting macroscopic fractures that intersect the wellbore and cut across lithologic or stratigraphic contacts, allowing for analysis of natural fractures (Figures 2.3a and 2.3b). GMI•Imager™, designed specifically for the analysis of digital wellbore image data, was used to interpret natural features in the EMI image data for the Coso wells.

Figure 2.3: Examples of EMI image data from Coso 38C-9. (a) Natural fractures, (b) fracture with a significant apparent aperture.

Planar features detected in electrical image data are the result of the electrical conductivity contrast between the feature and the host rock and appear as sinusoids on unwrapped 360° views
of the image data (e.g., Figure 2.3a). The true dip, true dip direction, and fracture density for all natural fractures were tabulated (Figures 2.4a, 2.4b, 2.4c, and 2.5a, 2.5b, 2.5c) taking into account the deviation of the borehole from vertical and the deviation direction. We also identified a subset of fractures with a significant apparent aperture (Figure 2.3b) in this well and analyzed their orientations (Figures 2.4d, 2.4e, 2.4f, and 2.5d, 2.5e, 2.5f). The apparent aperture observed in electrical image logs results from a high electrical conductivity contrast that can represent either the presence of a highly conductive fluid (e.g., drilling mud), or a highly conductive vein-filling material resulting from hydrothermal alteration. Thus, at least in some cases, fractures with significant apparent aperture due to mud infiltration may be acting as fluid flow pathways.

**Figure 2.4:** Coso 38C-9 fracture analysis results for the shallow logged interval, 690 to ~3,500 feet measured depth (MD). (a) True dip, (b) true dip direction, (c) fracture density of all natural fractures. (d) Apparent aperture, (e) true dip, (f) and true dip direction for fractures with a significant apparent aperture.
Figure 2.5: Coso 38C-9 fracture analysis results for the deep logged interval, 5,881–9,408 feet MD. (a) True dip, (b) true dip direction, (c) fracture density of all natural fractures. (d) Apparent aperture, (e) true dip, (f) and true dip direction for fractures with a significant apparent aperture.

Figure 2.6: True dip versus true vertical depth (TVD) for natural fractures in Coso East Flank wells.
Dips of all fractures range from moderate to steep (Figures 2.4a and 2.5a). Vertical fractures are observed where the wellbore deviation from vertical increases. Dip azimuths are bimodal, ENE to NNW in the shallow interval (Figure 2.4b) and NE and NW in the deeper interval (Figure 2.5b).

Dip azimuths of fractures with significant apparent aperture (Figures 2.4f and 2.5f) tend to mimic the dip azimuths of the bulk fracture population (Figures 2.4b and 2.5b), but they have steeper dips in the deep interval (Figure 2.5e compared to 2.4e) and when compared with the bulk fracture population (Figure 2.5a compared to 2.4a).

Summary plots show true dip (Figure 2.6) and true dip direction (Figure 2.7) versus true vertical depth for all wells analyzed in the Coso East Flank EGS project (38A-9, 38B-9, 38C-9, 83-16, and 86-17) prior to 2005. A more detailed analysis of these earlier data is presented in Sheridan et al., 2003 (Appendix B). Similar fracture sets are observed in most of the Coso East Flank wells where there are mainly two dip directions (Figure 2.7), but the dominance of one dip direction over the other varies from well to well and can also vary with depth within a single well. However, the strike of these dominant fracture sets mimics map-scale faults (Figure 2.1a) in the East Flank area.

2.1.3.2 Measurements of stress orientations from borehole image logs

Details of the stress state that these faults are subjected to have been revealed through the analysis of borehole image data and hydraulic fracturing stress measurements (Geomechanics International, 2003; Sheridan et al., 2003 (Appendix B, detailed data recorded in Appendix C);
Drilling-induced failure of the rock adjacent to the borehole wall results from the concentration of tectonic stress around the free surface of a borehole as well as immediately ahead of the drill bit (Figure 2.8). Field studies have demonstrated that these induced structures reliably record the orientations of the horizontal principal stress axes (see Moos and Zoback, 1990; Zoback et al., 2003; Davatzes and Hickman, 2005, Davatzes and Hickman, 2006). Three types of drilling-induce structures are recognized: (1) breakouts, (2) tensile fractures and (3) petal-centerline fractures (see Davatzes and Hickman, 2005a (Appendix A) for details). Breakouts are patches of the borehole wall that undergo compressive failure and occur in pairs oriented along the minimum horizontal principal stress ($S_{hmin}$) azimuth (Figure 2.8). In contrast, tensile failure of the borehole wall or ahead of the drill bit produces pairs of tensile fractures (Figure 2.8) and petal-centerline fractures (Figure 2.8) respectively that strike along the maximum horizontal principal stress ($S_{Hmax}$). These structures can be identified and their azimuthal orientations measured from oriented images of the borehole wall reflectivity, microresistivity and radius, providing a means to infer the direction of the horizontal principal stress axes.

**Figure 2.8:** Drilling-induced structures visible in borehole image logs indicating the modern orientation of the principal horizontal stresses. Along the top, examples of induced structures and their geometric relationships are illustrated by representative image logs and sketches. In the ABI85 amplitude image, breakouts appear as paired irregularly shaped patches 180° apart and offset 90° from tensile fractures, which appear as paired borehole axis-parallel or en echelon lineations 180° apart. In resistivity-based image logs borehole wall breakouts appear as
pairs of irregularly fuzzy (“out-of-focus”) patches. Petal fractures appear as smoothly curving chevrons in the ABI85 amplitude image and are difficult to recognize in resistivity-based image logs due to the partial imaging of the borehole wall. The arms of the chevrons merge with pairs of centerline fractures oriented parallel to the borehole axis, but with variable azimuthal separation. Note that the borehole images are un-wrapped from a full 360° view, thus planar structures intersecting the borehole appear as sinusoids. Along the bottom of the figure, the angular relationships of these induced structures to the horizontal stresses are illustrated.

Studies before 2005 did not distinguish tensile fractures from petal-centerline fractures and were limited to resistivity based imaging tools that incompletely image the borehole wall. However, the relatively low standard deviations in these data sets suggest that they can be incorporated with the more precise data sets generated during 2005 and 2006 that use both the new Borehole Televiewer tool as well as the resistivity based tools. The detailed analyses of the East Flank wells analyzed prior to 2005 are included as Appendices B and C; these results are integrated into the final data analysis and discussed in the following text. The potential shortfalls of these analyses are discussed in detail in Appendix A.

Image logs were checked against borehole deviation surveys and other overlapping image logs to verify accurate image orientations. Borehole deviation over the interpreted intervals range from 3º to 15º which allowed us to neglect corrections required for highly deviated boreholes (Peska and Zoback, 1995). Following the method of Davatzes and Hickman (2005a) the orientation of $S_{\text{hmin}}$ was determined from the average of pairs of petal-centerline fractures or tensile cracks. Thus, tensile fractures of either kind were only picked when they occurred as pairs. Mean orientations of $S_{\text{hmin}}$ are calculated by averaging the orientation of induced structures weighted by their cumulative lengths. Each type of structure was given equal value in this analysis. For brevity we only present stress directions from wells 38C-9, 34-9RD2, and 58A-10 for which data on stress magnitudes is discussed in Section 2.1.3.2 and 3.1.2. Additional detailed analyses of stress directions measured in other wells are available in Appendices B and C.

Analyses of image logs acquired in 34-9RD2 and the other East Flank wells and 58A-10 reveal extensive suites of drilling-induced petal-centerline fractures, tensile borehole wall fractures, and to a lesser extent borehole wall breakouts. No breakouts were observed in the East Flank well 34-9RD2 (Figure 2.9), which is similar to the analysis of nearby well 38C-9 in which only one breakout was seen (Figure 2.10) (Sheridan and Hickman, 2004). However abundant tensile fractures and petal centerline fractures indicate that the azimuth of $S_{\text{hmin}}$ in proximity to the well is bimodal (Figure 2.9a). The dominant mode is 099º ± 18º, and a subsidiary mode with limited vertical extent is 176º ± 15º (Figure 2.9b). In well 38C-9, observations of drilling induced tensile fractures and a single breakout indicate that the azimuth of $S_{\text{hmin}}$ is 101º ±17º (Figure 2.11). (Note that well 38C-9 was analyzed prior to the recognition of petal-centerline fractures. As a result, the analysis does not take into account this source of error. However, the small standard deviation indicates that petal-centerline fracture did not adversely affect the estimation of the stress direction.) In Coso Wash well 58A-10, breakouts are more prevalent but are narrow and shallow. Overall, they represent a small percentage of the total length of induced structures. Near well 58A-10, $S_{\text{hmin}}$ is oriented along an azimuth of 108º ± 15º (Figure 2.11a).
Figure 2.9: Well 34-9RD2 (a) Rose diagram of induced structure orientations weighted by structure length in 5° bins. (b) Depth distribution and orientations of $S_{\text{hmin}}$ inferred from drilling-induced structures in well 34-9RD2 (location in Figure 2.1). Depth units are measured depth (MD). Some tensile cracks could not be distinguished between petal centerline cracks and borehole wall tensile fractures and are correspondingly marked.
Figure 2.10: Well 38C-9 (a) Rose diagram of induced structure orientations weighted by structure length. (b) Depth distribution and orientations of $S_{hmin}$ inferred from drilling-induced structures in well 38C-9 (location in Figure 2.1; Legend in Figure 2.9).
Figure 2.11: Well 58A-10 (a) Rose diagram of induced structure orientations weighted by structure length in 5º bins. (b) Depth distribution and orientations of $S_{hmin}$ inferred from drilling-induced structures in well 58A-10 (location in Figure 2.1; Legend in Figure 2.9). (c) Cumulative length of breakouts of different angular width.
We integrated the data from wells 34-9RD2, 38C-9, and the other East Flank analyses (Appendices B and C) with data from Coso Wash including well 58A-10 and existing analyses conducted by Geomechanics International (2003) after careful quality checking to investigate the variation of stress orientations in the East Flank and Coso Wash. In general, the mean azimuth of $S_{hmin}$ in wells throughout both areas is $\sim 108^\circ \pm 24^\circ$ (Figure 2.1b). This orientation is consistent with the N- to NNE-striking normal faults that seismicity and/or geomorphology indicate are currently active (Figure 2.1a). Inside the East Flank, stress orientations indicate somewhat greater heterogeneity than in Coso Wash. Wells 38A-9, 38C-9, and 34-9RD2 indicate stress orientations more similar to the Coso Wash wells. However, wells 38B-9, 83-16, and the subsidiary mode in 34-9RD2 (Figure 2.9) suggest that $S_{hmin}$ is oriented approximately NNW-SSE.

Detailed examination of variations in borehole failure orientations with depth reveals numerous localized stress rotations, such as the prominent rotations at about 5100 ft measured depth (MD) in well 34-9RD2 (e.g., Figure 2.9b) and at 9700 ft MD in well 58A-10 (Figure 2.11b). Our preliminary modeling of these local rotations in $S_{hmin}$ (not presented here) suggests that they result from slip on faults, indicating active deformation in the crust of the East Flank and adjacent Coso Wash. The range of rotations up to $70^\circ$, suggesting fault slip at a variety of scales consistent with micro-seismicity and the abundant large-aperture faults visible in image logs (Sheridan and Hickman, 2004; Geomechanics International, 2003; Davatzes and Hickman, 2005a).

In addition to our borehole analyses, several studies have mapped spatial variations in the local state of stress or incremental strain by inversion of spatially clustered populations of earthquake focal mechanisms (Feng and Lees, 1998; Unruh et al., 2002). The orientations of the least principal compressive stress or extension direction predicted by these methods are generally uniform within the geothermal field (Figure 2.1b) and similar to borehole measurements. Due to the low rates of seismicity, results for Coso Wash are not available for comparison with borehole results. However, stress directions indicated by extensive borehole observations in Coso Wash are consistent with extension accommodated by adjacent N- to NNE-striking faults such as the Coso Wash fault segments.

### 2.1.3.3 Summary of faults, fractures, and stress orientations

Stress orientations from both borehole data and earthquake focal mechanism inversions suggest a consistent remote horizontal stress orientation where $S_{hmin}$ is $\sim 108^\circ \pm 24^\circ$ throughout the productive geothermal field. The image analysis for 38C-9 shows a preponderance of moderate to steeply dipping fractures, dipping towards either the northeast or northwest, similar to results from other wells in the area. These fracture orientations are consistent with analyses of other East Flank wells and with the larger faults in the geothermal field. At the reservoir scale, normal faults trending N-S to NNE-SSW appear to be most active based on the offset of Quaternary to Holocene sediments and are well oriented relative to the current azimuth of $S_{hmin}$.

### 2.1.4 Direct measurements of East Flank stress magnitudes
We used a variety of techniques to determine the magnitude of $S_{h\text{min}}$ and $S_{H\text{max}}$ in the East Flank. The magnitude of $S_{h\text{min}}$ was determined from a hydraulic fracturing stress test conducted previously in well 38C-9 (Sheridan and Hickman, 2004) and a new test conducted in well 34-9RD2 in February 2005 (presented here for the first time). In addition, upper bounds on the magnitudes of $S_{H\text{max}}$ were obtained through borehole failure analyses based upon the presence or absence of breakouts in wells 34-9RD2, 38C-9, and 58A-10 (well locations in Figure 2.1). The stress model developed from these results is discussed in Section 3.1.1.

2.1.4.1 Hydraulic fracturing stress magnitudes in well 38C-9

As done in other geothermal fields (see Hickman et al., 1998, 2000), following cementation of the casing at a depth of 3,684 feet MD, a 57-foot long pilot hole was drilled out the bottom of the well in which to conduct the hydraulic fracturing test. The entire casing string was pressurized to induce a hydraulic fracture in the uncased pilot hole (Figure 2.12). Repeated pressurization cycles were then employed to extend this fracture away from the borehole. Pressures and flow rates were measured at the surface and a high-accuracy, temperature-compensated, quartz pressure gauge was suspended 42 feet above the center of the test interval to provide a continuous record of downhole pressure during this test.

![Figure 2.12: Schematic illustration of a hydraulic fracturing (minifrac) test.](image-url)
Following Hickman and Zoback (1983), the magnitude of the least horizontal principal stress, $S_{\text{Hmin}}$, was determined from the instantaneous shut-in pressure (ISIP), or the pressure at which the pressure-time curve departs from an initial linear pressure drop immediately after the pump is turned off and the well is shut in (Figures 2.13a and 2.14). The interpretation of the 38C-9 hydraulic fracturing test was complicated by the fact that a highly permeable interval of the formation was encountered during drilling of the 57-foot pilot hole, causing rapid fall off in the standing water level in the well both prior to conducting the hydraulic fracturing and between pumping cycles (Figure 2.13b) and rapid pressure decays during hydraulic fracturing shut in periods (Figure 2.13a). In spite of this rapid decay in shut-in pressure, by expanding the time scale we were able to make six determinations of the ISIP (Figure 2.14). As discussed in Hickman et al. (1988), the observation that the values determined for ISIP were relatively repeatable and insensitive to variations in pump rate immediately preceding shut in (Figure 2.13a) indicates that viscous pressure losses within the hydraulic fracture near the borehole had a negligible effect on the ISIP values and that we are obtaining a good measure of $S_{\text{Hmin}}$ magnitude. Thus, analysis of the hydraulic fracturing data from well 38C-9 shows that the magnitude of $S_{\text{Hmin}}$ at 3,703 feet TVD is 2,645 ±77 psi (Figure 10). Using an estimated granite density of 2.63 gm/cm$^3$ indicates that the magnitude of $S_{\text{Hmin}}$ at this depth is about 0.63 of $S_V$. This is at the high end of the range observed within the producing portions of the Dixie Valley Geothermal Field, where $S_{\text{Hmin}}/S_V$ ranges from 0.45–0.62 at depths of 0.4–2.5 km (Hickman et al., 1998, 2000).

![Graph](image)

**Figure 2.13:** (a) Surface pressure and flow rate records from the hydraulic fracturing test conducted in well 38C-9. (b) Expanded scale showing rapid drop in borehole water level between pumping cycles due to high test-interval permeability.

Downhole pumping pressures were recorded during a stepwise change in flow rate in the last cycle of this test in an attempt to detect changes in the permeability of the test interval resulting from closure of the hydraulic fracture near the wellbore. However, interpretation of this portion of the test is ambiguous owing to the very high test-interval permeability encountered and the currently low reservoir pressure at this depth.
In a hydraulic fracturing test, the magnitude of $S_{H_{\text{max}}}$ is sometimes determined using a fracture initiation, or breakdown, criteria derived for pure mode I tensile fractures initiating in intact (i.e., un-fractured) rock along the $S_{H_{\text{max}}}$ direction. However, as was the case in similar tests conducted in the Dixie Valley Geothermal Field (Hickman et al. 1998, 2000), borehole image logs conducted in well 38C-9 show pervasive pre-existing fractures at a variety of orientations. Thus, as described in section 3.1.1, we derive upper bounds on the magnitude of $S_{H_{\text{max}}}$ using our measured $S_{h_{\text{min}}}$ value and the near-absence of borehole breakouts in this well.

**Figure 2.14:** Expanded view of shut-in pressure decay at the end of the 3rd cycle, showing how the instantaneous shut-in pressure was determined.

### 2.1.4.2 Hydraulic fracturing stress magnitudes in well 34-9RD2

As done in well 38C-9, following cementation of the casing at a depth of 7903 ft measured depth (MD), a 79-foot-long pilot hole was drilled out the bottom of the well in which to conduct the hydraulic fracturing test. A drill-pipe-deployed packer (RTTS tool) was then set in the cased hole at a depth of 7869 ft MD and the pipe was pressurized to induce a hydraulic fracture in the uncased pilot hole. Repeated pressurization cycles were then employed to extend this fracture away from the borehole (Figure 2.15a). Pressures and flow rates were measured at the surface and extrapolated to depth using a fluid pressure profile determined immediately before the hydraulic fracturing in conjunction with a high-accuracy, temperature-compensated quartz pressure gauge run inside the drill pipe to a depth of 7479 ft MD. This gauge encountered a restriction in the pipe internal diameter at this depth and had to be removed before the test could begin.

Again, the magnitude of $S_{h_{\text{min}}}$ was determined from the instantaneous shut-in pressure (ISIP) (Hickman and Zoback, 1983), or the pressure at which the pressure-time curve departs from an initial linear pressure drop immediately after the pump is turned off and the well is shut in (Figure 2.15b). Although we typically run a hydraulic fracturing test for multiple cycles to check for repeatability of the ISIP, the RTTS tool failed in the middle of the third cycle, allowing fluid to bypass the packer and flow out the top of the casing. However, the ISIP determined from the second cycle was very distinct (Figure 2.15b) and the observation that the pumping pressure in cycle 3 just before the RTTS tool failed had leveled out at close to the value attained in cycle 2 suggests that viscous pressure losses within the hydraulic fracture near the borehole were very small and that the ISIP from the second cycle is a good measure of $S_{h_{\text{min}}}$ (see discussion of the
relation between pumping pressure and ISIP in Hickman and Zoback [1983] and Hickman et al. [1988]). Thus, using directional surveys to convert from MD to total vertical depth below ground level (TVD), our analysis of the hydraulic fracturing data from well 34-9RD2 shows that the magnitude of $S_{\text{hmin}}$ at 7817 feet TVD is 5635 ± 200 psi.

![Figure 2.15](image)

**Figure 2.15:** (a) Surface pressure and flow-rate records from the hydraulic fracturing stress measurement conducted in well 34-9RD2 at a measured depth (MD) of 7903-7982 ft. For the first two cycles, fluid was pumped into the well at flow rates of 1-2 barrels/min for about 1 minute, the well was shut in and the pressure monitored for about 5 minutes, and the wellhead was vented to the drill sump (flowback) to drain the hydraulic fracture prior to the next cycle. This test was terminated prematurely after the RTTS packer failed in the middle of the third cycle. Fluid was pumped to the drill sump (bypassing the well) between cycles 1 and 2 in an unsuccessful attempt to reactivate a malfunctioning flow meter. (b) Expanded view of cycle 2 from this test, showing how the instantaneous shut-in pressure (ISIP, also shown in Figure 5a) was determined. Note how the pressure flattens out and then drops slightly during pumping, indicating that the hydraulic fracture has reopened and is propagating away from the borehole prior to shut in.

### 2.1.4.3 Summary of hydraulic fracturing experiments

Two hydraulic fracturing experiments were completed in the East Flank. Together they define a gradient in depth for $S_{\text{hmin}}$ which is an integral part of the stress model for the East Flank and critical to defining the tectonic regime. These measurements guided the modulation of fluid pressures to induce shear failure on existing fractures within the reservoir as part of the EGS stimulation strategy in the attempted stimulation of well 34-9RD2 and will contribute to the successful stimulation of EGS well 46A-19RD in 2006.
2.1.5 References


Moos, D. and Zoback, M.D., (1990), Utilization of observations of well bore failure to constrain the orientation and magnitude of crustal stresses: Application to continental, deep sea drilling project, and ocean drilling program boreholes, Journal of Geophysical Research, 1000(B), 12791-12811.


Sheridan, J. and Hickman, S., (2004), In situ stress, fracture and fluid flow analyses in well 38C-9: An enhanced geothermal system in the Coso geothermal field, 29th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 26-28, SGP-TR-175, 8 pp.


2.2 Petrology and Petrography (Katie Kovac and Joe Moore)

2.2.1 Background and Objectives

Petrographic and petrologic studies were implemented to 1) construct the overall geologic framework of the East Flank; 2) document and characterize geothermal and older fluid flow paths; and 3) aid in the interpretation of FMS and borehole televiewer logs. Where possible, the intervals chosen for study were selected because the corresponding FMS data were fair-to-good in quality.

Cuttings and thin sections from many East Flank wells were studied. Chipboards and thin sections were created and analyzed for key intervals in the wells. Studies of these samples provided data including: rock type and mineralogy, relative amount of overall alteration, relative amounts and mineralogy of the veining, the presence of open-space fillings, and presence of brecciation. In addition, fluid inclusion and x-ray diffraction studies were implemented to assist in separating different thermal events, and thus in assembling the thermal history of the system.

Lithologically, the East Flank is dominated by quartz diorites, granodiorites, and granites. The quartz diorites and granodiorites are considered to be Mesozoic in age. These host rocks comprise part of the Sierra Nevada batholith (Duffield et al., 1980). Field relationships and age dates indicate that the granite intrusions are younger than the other rock types (Moore et al., 2004; Kurilovitch et al., 2003; Duffield et al., 1980). Also, young felsic dikes occur in the area, which are represented by thin microgranite intervals in some wells.

As a result of this work, a detailed understanding of the thermal structure of the reservoir has emerged. Evidence of several episodes of hydrothermal activity has been preserved in the reservoir rocks, and preliminary fluid inclusion data (previous quarterlies; Adams et al., 2000) as well as other data suggest that temperatures beneath the East Flank of the field are rising (Bishop and Bird, 1987; Lutz et al., 1999; Manley and Bacon, 2000).
In this work, a comprehensive paragenetic sequence of the vein minerals was created, the dominant host rock lithologies were characterized, and a basic geologic model of the East Flank was constructed. Petrographic and mineralogic work on the core and thin sections, fluid inclusion studies, and geochemical data were employed. These investigations have contributed to a greater understanding of the geothermal system, the reservoir lithology, and the interplay between the two.

### 2.2.2 Petrology and Petrography of Well 38C-9/38C-9ST

A total interval of 5000 ft to depth (9000 ft) was chosen for the composite detailed study interval on this well. This interval was chosen in order to complement data and observations from the geophysical studies. Chipboards were constructed from 4000 ft to depth; thin sections were made every 50 feet for 5000 ft to depth (Figures 2.16, 2.17, 2.18, 2.19). In this well, the dominant rock type was metamorphic hornblende biotite quartz diorite. The hornblende diorites are the dominant rock type present. The biotite quartz diorite was fairly rare; at this time it seems that this rock type is more common in the shallow intervals.

Towards the middle of the interval, the microgranite gets more pervasive, finger ing into about four main sections starting at around 6800 ft. Alteration was generally moderate, although there were several locations where it was stronger than was commonly seen in other wells. Compared with the trends noticed in other wells, the diorites showed the strongest pervasive alteration in this well in the 5000-7500 ft interval. Zones of lost circulation reported on the mudlogs were noted and plotted with the petrographic data. Roughly, the lost circulation zones correlate to zones with much veining and often open-space crystals. (This interval seemed to have the most quartz veining and open-space quartz crystals of any of the study wells, as well as more pyrite/chalcopyrite (not shown)). Figures 2.16 and 2.19 show a summary of veining with depth for the studied intervals. Open space crystal locations also are shown in Figures 2.16 and 2.19. In this well there were proportionately more quartz crystals than calcite crystals compared to most prior studied wells’ ratios.
Figure 2.16. Rock type and veining data from 5000 ft to 7500 ft for 38C-9 & 38C-9-ST.
Figure 2.17. Veining vs. depth for well 38C-9 from 6000 ft to depth.
Figure 2.18. Comparative lithologies of the three wells of the 38 pad for the studied interval.
The interval from 3600 ft to depth (9730 ft) in well 34A-9 was analyzed. Both thin sections and chipboards were created and studied from available cuttings. The usual petrographic and petrologic data were collected, including rock type, amount of pervasive alteration, amount of veining, open space crystal locations, and other observations. Summary plots of some of the petrographic observations made are shown in Figures 2.20 and 2.21. The detailed charts of the key observations for this well are shown in Figures 2.22-2.24. As in the middle portion of well 34-9RD2, this well contained a substantial interval of granite from approximately 5100-6250 ft. This well had more quartz veining than usual for the study wells, and many small, euhedral quartz crystals were found. Several intervals contained especially large amounts of veining, such as: 4600-4700 ft, 7450-70 ft, 9100 ft, and 9570-90 ft. This well was also unusual in that deep adularia veining was found. Adularia was found with euhedral quartz, which suggests boiling. Adularia was found by thin section identification at 7350 ft, 7570 ft, 7600 ft, 7630 ft, and 9710 ft. More epidote veining than usual was identified. Also, wairakite, which is extremely rare in the study wells, was found at 9710 ft. In fact, at 9710 feet, the wairakite was found to postdate...
the assemblage quartz + sericite + iron-poor epidote + adularia +/- chlorite. A paragenetic chart developed specifically from observations on this study well is shown in Figure 2.25.

Figure 2.20. *Summary of petrographic observations made on well 34A-9.*
Figure 2.21. A summary of major veining observations made on well 34A-9.

Figure 2.22. Summary chart of observations on shallowest interval studied in well 34A-9.
Figure 2.23. Summary chart of observations for the middle interval of study well 34A-9.

Figure 2.24. Summary chart of observations on the deepest interval of study well 34A-9.
2.2.4 Petrology and Petrography of Well 34-9RD2

As this well was chosen for the initial hydrofracture experiment, it was the subject of detailed study. The chosen interval of study was from 3600 feet to depth (~7300 feet). Both thin sections and chipboards were created and studied for this interval from available cuttings. Figures 2.26 and 2.27 display a summary of rock type, pervasive alteration intensity, lost circulation, and veining information as a function of depth for the well. The color code for the rock types shown is as follows: dark green is hornblende biotite quartz diorite, pale green is metamorphic hornblende biotite quartz diorite, yellow is biotite quartz diorite, orange is biotite granodiorite, pink is granite, red is microgranite, lavender is metasediments, and light blue is nearly total veining.

The large section of granite shown from approximately 5000 ft to 6800 ft was the longest continuous granitic section encountered in any of the study wells. Usually granite is less common than the other rock types. The unusually long granitic intervals in wells 34A-9 and 34-9RD2 probably indicate proximity to an intrusion. The granite contained occasional metasediments that appeared to be marl. In some places, the granite was more altered than usual (see figures), although usually it was still less altered than the other major rock types. There were a number of zones that show at least some lost circulation in the well, but below about 5600 ft there is almost none. Granitic intervals seem to correlate with zones of negligible lost circulation and also generally a decrease in the amount of veining. Open space crystals were found intermittently throughout the interval and were, as usual, most commonly calcite. However, both in this well and in well 34A-9 quartz crystals were more abundant than usual.
Figure 2.26. Depth versus rock type, pervasive alteration intensity, lost circulation, quartz veining, calcite veining, chlorite veining, hematite veining, and open space crystal locations for well 34-9RD2 from 3600-5300 ft. Scales with no numbers plot only presence or absence of a feature. See text for a description of rock types.
Figure 2.27. Depth versus rock type, pervasive alteration intensity, lost circulation, quartz veining, calcite veining, chlorite veining, hematite veining, and open space crystal locations for well 34-9RD2 from 5300-7310 ft. Scales with no numbers plot only presence or absence of a feature. See text for a description of rock types.

2.2.5 Fluid Inclusion Studies

Fluid inclusion samples were collected, prepared, and analyzed for many East Flank wells. All of the inclusions found in these samples were two-phase (liquid and vapor) at room temperature. Homogenization temperatures and salinities of the inclusion fluids calculated as weight percent NaCl equivalent (Bodnar, 1993) were determined. For example, Figure 2.28 summarizes relationships between depth, homogenization temperature, and salinity for inclusions from well 34-9RD2. The measured downhole temperatures and boiling point to depth curve for a 0% salinity, gas-free fluid are also shown for comparison. Salinities are coded by symbol size.

Inclusions in calcite had the lowest temperatures and salinities. Temperatures of homogenization in calcite varied between 150 and 215°C, and salinity varied between 0.9 to 2.7 weight % NaCl equivalent, which is generally the higher end of calcite salinities as measured in other wells. Quartz varied in homogenization temperatures between 175 and 213°C, and salinities varied between 1 and 4 wt. % NaCl equivalent. The primary inclusions in quartz had higher salinities
than the secondary inclusions in quartz. The inclusions in epidote had by far the highest
measured temperatures and salinities. Homogenization temperature was approximately 268°C
while salinity was approximately 11 wt. % NaCl equivalent.

Figures 2.29 and 2.30 show temperature versus depth and temperature versus salinity for all
measured East Flank inclusions. Samples are coded according to morphology, where triangle =
scalenohedral calcite, square = blocky calcite, circle = sealed vein calcite, diamond = quartz and
asterisk = epidote. Samples are also coded according to paragenetic stage, where white = Stage
1, dark grey = Stage 2, black = Stage 3 and light grey = Stage 4. Salinity varies from 0 to about
10 wt. % NaCl equivalent for all inclusions. Temperature varies more than 200 degrees, with the
coldest inclusions 117°C and the hottest 327°C. It is evident that both temperature and salinity
span a wide range of values for vein minerals from the East Flank.

Histograms of salinities determined on calcite- and quartz-hosted inclusions suggest that several
(three or more) distinct populations of fluids were trapped (Figures 2.31 and 2.32). Data from all
studied East Flank wells were employed. See Appendix J for a summary of fluid inclusion data
collected on corehole 64-16. More than half of the inclusions trapped in calcite recorded
salinities between 0.5 and 1% NaCl equivalent; furthermore, over 70% of all calcite inclusions
have salinities less than 1 weight percent equivalent.

Salinities in quartz-hosted inclusions also define several populations with salinities tending to be
higher than in the calcite. Less than 25% of the inclusions have salinities of 1 weight percent
NaCl equivalent or less. Significantly, almost 20% of the quartz inclusions had salinities of 5 wt.
% NaCl equivalent and higher. Thus the fluid inclusion data provide a record of water-rock
interactions that involved fluids with a wide range of compositions. The earliest fluids trapped in
quartz and calcite deposited during Stage 1 had the highest salinities of about 8-10 weight
percent NaCl equivalent. The youngest thermal event is represented by the lowest salinity fluids,
which are usually equal to or less than 1 weight percent NaCl equivalent.

Homogenization temperatures in calcite ranged between 137-215°C. In quartz, they ranged
between 175-215°C. From the fluid inclusion data in conjunction with the paragenetic data, it is
evident that most of the inclusions that are considered to be relatively late-stage (more recent)
have temperatures which are lower than present day temperatures and salinities of about 1 wt. %
NaCl equivalent (Kovac et. al, 2004). Meanwhile, some of the older inclusions in minerals like
episode, quartz, and some calcite have temperatures well above present day, and salinities that in
episode are as high as 11 wt. % NaCl equivalent. These are not presumed to be related to the
current geothermal system. This pattern is inferred to suggest the system is currently reheating.

Figure 2.33 shows the generalized fluid evolution path for the upper several thousand feet of the
field. For each paragenetic stage, a representative temperature and salinity were selected.
Generally, salinity has decreased over time; temperature has generally decreased, although it
follows a more circuitous path, ending in modern reheating.
Figure 2.28. Depth vs. temperature of homogenization for inclusions from well 34-9RD2. Symbol size correlates with salinity. See text.

Figure 2.29. A summary of fluid inclusion homogenization temperature versus depth for East Flank inclusion data.
Figure 2.30. A summary of homogenization temperature versus salinity for East Flank fluid inclusions.

Figure 2.31. Relative Frequency of salinity in calcite fluid inclusions.
Figure 2.32. Relative frequency of salinity in quartz fluid inclusions.

Figure 2.33. Generalized fluid evolution over time, with average values for the upper several thousand feet portion of the East Flank.
2.2.6 X-Ray Diffraction Studies

Both bulk and clay mineralogy with depth were analyzed for many of the East Flank wells by X-ray diffraction methods (Lutz, 1997; Lutz, unpub. data; Kovac et al., 2005). The usual x-ray preparation and analysis methods described in Moore and Reynolds (1989) were used. The abundances of chlorite, smectite, illite-smectite, and illite + mica as a percentage of the bulk rock were determined. These minerals are especially significant because they have relatively restricted thermal stabilities. In theory, mineral stability will be a function of mineral chemistry. These temperatures of maximum stability are appropriate in application to a relatively wide range of igneous protoliths, including the dominant rock types (quartz diorites, granodiorites) of the Coso geothermal system. In active geothermal systems, smectite is stable up to temperatures of ~180°C, interlayered illite-smectite to temperatures ~225 °C, and illite and micas at greater temperatures (Henley and Ellis, 1983; Browne, 1984). Chlorite is stable between ~120-200+°C, and the transition from a smectite-dominated assemblage to a chlorite-dominated assemblage takes place between 150-200°C (Henley and Ellis, 1983; Robinson et al., 1999).

Cuttings samples were collected and analyzed for x-ray diffraction analysis. Some x-ray diffraction data was provided by S. Lutz (Lutz, 1997). The plot of clay minerals with depth for both wells is shown in Figure 2.34. Some trends become apparent in examining this plot. First, the amount of chlorite present in the clays is smaller from about 5000-7000 feet, which corresponds to the granite-dominated intervals. Secondly, the amount of smectite present in well 34-9RD2 is most substantial from 4800-5500 feet, also roughly corresponding to the top of the granite. Thirdly, the most abundant clays present are illite+mica and illite-smectite. Fourthly, (not shown on graph), there was no apparent trend in percent smectite in the illite-smectite with depth, indicating that this clay mineralogy is not reflecting the present-temperature regime.
Figure 2.34. Clay mineral abundances with depth for wells 34-9RD2 and 34A-9. The reference for the theoretical stability temperature ranges for the clay minerals is Henley and Ellis, 1983.

Bulk compositional data was also analyzed by x-ray diffraction. The summary plot of bulk clay data with depth alongside present day temperature with depth curves is shown in Figures 2.35 and 2.36. Fluid inclusion data for well 34-9RD2 was included for comparison on Figure 2.36. The present temperatures can be compared with the theoretical breakdown temperatures for smectite and illite-smectite (Henley and Ellis, 1983). The dashed lines indicate the inferred locations of disappearance of smectite and illite-smectite with depth. The present day temperatures are at least slightly hotter for the smectite (~20-40°C). In the case of illite-smectite in well 34A-9, the temperature difference is about 100°C, suggesting this mineral formed during an earlier, lower temperature thermal event. These relationships suggest recent heating of the field, which has not yet been recorded by the rocks.
2.2.7 Thermal Modeling of the Coso East Flank Compartment

The clay mineral distribution in well 64-16 compared to the present day temperatures is shown in Figure 2.35. The plot suggests that smectite is not stable below approximately 4000 ft, indicating temperatures around 180°C, and illite-smectite disappears at approximately 7000 ft, indicating temperatures around 225°C. When compared to the measured present day temperature estimates of about 230°C and 262°C, respectively, the clay minerals predict temperatures that are too low.

For well 51A-16, also shown in Figure 2.35, only the relative presence or absence of the clay minerals was determined, so these were plotted simply as present (1) or absent (0) (Lutz, unpub.data). In this well, both smectite and illite-smectite disappear at much shallower depths than in the other wells. For the case of smectite, the temperature predicted is slightly too high compared with the present day temperature (~160°C). For illite-smectite, the temperature predicted is too low compared with the present temperature (~260°C).

Wells 34A-9 and 34-9RD2 display similar relationships (Figure 2.36). In well 34-9RD2, the temperature predicted by the disappearance of smectite was slightly lower (180°C compared with ~200+°C) than the present day temperature (Kovac et al., 2005). However, the temperatures recorded by calcite hosted fluid inclusions in this well are in good agreement with the temperatures indicated by the clay mineralogy. Well 34A-9 yielded the highest present—day temperatures in the field. The temperature predicted by the disappearance of smectite was approximately 40°C too low compared with the present temperature (~220°C). The difference
between the measured temperature and the temperature predicted by the disappearance of illite-smectite shows even greater disparity. Here, the predicted temperature was approximately 100°C too low compared with the present-day temperature (over 325°C).

Figure 2.36. Percent of clay minerals of the bulk mineralogy with depth for wells 34-9RD2 and 34A-9 with depth. Present temperature curves for both wells as well as fluid inclusion data for well 34-9RD2 is also shown. The reference, for the theoretical stability temperature ranges for the clay minerals is Henley and Ellis, 1983.

High-temperature geothermal reservoirs typically have temperatures exceeding 250°C. Minerals stable at low to moderate temperatures such as smectite (<180°C; Henley and Ellis, 1983), illite-smectite (present between 180°C-225°C; Henley and Ellis, 1983), and stilbite (90°C-125°C; Browne, 1984), are typical of the caprock section. Minerals stable at higher temperatures, such as wairakite (230°C-300°C; Moore, 2004), epidote (250°C-350°C; Henley and Ellis, 1983), and illite (>225°C; Henley and Ellis, 1983) are characteristic of the reservoir portion of a geothermal system.

The smectite, illite – smectite, and illite zones are shown on a simplified cross-sectional view of the four wells, 34A-9, 34-9RD2, 51A-16 and 64-16 (Figure 2.37). The present day 100°C, 200°C, and 300°C isotherms are indicated as dashed lines on the figure (well 34-9RD2 was left
out in drawing the isotherms, as its temperature profile is considered to be inaccurate). It is evident that the temperatures predicted at depth by the clay minerals are sometimes too low in comparison with the present day temperatures. In the case of well 34A-9, the discrepancy is over 100°C. A possible explanation for the discrepancy is that the present temperatures reflect recent heating, and the clay minerals have not had a chance to equilibrate yet. Manley and Bacon (1999) found that at least over the past 0.6 Ma, the depth from which eruptions occur has decreased, and the temperatures of the erupting rhyolites themselves have gotten slightly hotter. These changes are consistent with prograde heating of the system.

Silicate minerals also indicate some apparent contradictions. Figure 2.37 shows locations where relevant silicate minerals such as smectite, wairakite, stilbite, and acicular epidote have been found in the four study wells. An interval containing stilbite was found in well 64-16 from ~4900 to 6900 ft. Stilbite indicates temperatures between 90-130°C (Browne, 1984). The present temperatures in this interval were between ~235-261°C. At depths deeper than ~7000 ft in wells 34A-9 and 51A-16, wairakite and acicular epidote (34A-9 only) were found. The temperature ranges implied by these minerals (230-300°C and 250-350°C, respectively) are much too low for well 34A-9, but are reasonable for well 51A-16. Temperatures from fluid inclusions were usually in good agreement with temperatures indicated by the clay and silicate minerals.

The locations of sinter, hydrothermal breccias, and major lost circulation zones are also noted on Figure 2.37. Siliceous sinter was observed at the Wheeler Prospect, adjacent to the 64-16 wellpad, indicating that geothermal fluids discharged at the surface in the past. This is consistent with the observation that quartz- and calcite- cemented hydrothermal breccias are present in the upper portion of the 64-16TCH core. Furthermore, much of the quartz from this zone was found to have varying salinities, which suggests boiling (Shepherd et al., 1985). It is likely that in the large-scale view of the geothermal field, almost all of well 64-16 (and certainly all of corehole 64-16TCH) represents the impermeable caprock of the system. Lost circulation zones usually indicate major fractures, which are capable of substantial fluid flow. Many of the major lost circulation zones encountered are found relatively deep in the East Flank wells. Some shallow and moderate interval lost circulation zones also exist. However, most of the production zones (lost circulation zones that produce fluid) occur deep in the drilled wells, usually ~7000-8000 ft.

Exactly where the caprock–reservoir boundary lies is unclear, as the different types of data disagree. In looking at the temperature profile for well 64-16, reservoir temperatures (around 250°C) are reached at approximately 5500 ft. At this depth, the temperature profile steepens, which would be consistent with convection-dominated heat transfer. The appearance of lost circulation zones at 8400 ft could indicate reservoir conditions. Illite-smectite disappears at approximately 7000 ft. Thus, depending on which data are considered, the caprock–reservoir transition could occur anywhere from 5500 – 8400 ft.

In well 51A-16, the present-day temperature profile would indicate the caprock–reservoir transition at approximately 3200 ft. Lost circulation zones begin at approximately 7000 ft. At 7000 ft, mineralogy consistent with reservoir conditions was also found (wairakite after ~7000 ft).
In well 34A-9, the present–day temperature profile indicates that the caprock–reservoir transition occurs at approximately 3500 ft. However, shallow lost circulation zones found in this well disappear around that depth, and afterwards only minor lost circulation is found after 5900 ft. From the mineralogy, it is unclear exactly where illite–smectite disappears, but it is presumed to disappear around 8300 ft. Reservoir minerals such as adularia, wairakite, and epidote were found in this well below ~7000 ft.

In all three wells, the present–day temperature profiles indicate that the reservoir-caprock transition occurs at shallower depths than indicated by the structural, fluid inclusion, and mineralogical data. Furthermore, the clay mineralogy, silicate mineralogy, and fluid inclusion temperatures all generally indicate lower temperatures than measured present-day temperatures. This indicates that the present system is superimposed on an older, lower temperature system, and currently the field is heating. Being cooler, the paleosystem had a deeper caprock-reservoir boundary than the present day system. Furthermore, most of the present day production zones lie within the reservoir portion of the paleosystem. Therefore, the structure of the paleosystem appears to have had an effect on the characteristics of the present geothermal system.
Figure 2.37. A simplified cross-sectional view across the four wells, 34A-9, 34-9RD2, 51A-16, and 64-16. The present-day isotherms are shown as the dashed lines as indicated. The smectite, illite-smectite, and illite zones are also shown. The inferred paleosystem boundary between the caprock and the reservoir based on the mineralogy is shown as the solid line in the figure. See text for further discussion.

2.2.8 References


### 2.3 Microseismics (Bruce Julian and Gillian Foulger)

#### 2.3.1 Background and Objectives

The purpose of this project is to improve our understanding of fracture systems and geothermal fluids at the Coso geothermal area and how they change in response to geothermal operations and hydraulic fracturing experiments conducted to produce an Engineered Geothermal System (EGS). To do this, we apply modern seismological methods to determine complete earthquake mechanisms, high-resolution hypocenter locations, and four-dimensional (time-varying three-dimensional) structure. The information to be gathered bears directly on:

- Fracture geometry (locations, dimensions, orientations, growth)
- Fracture type (shear faults vs. mode-I cracks; creation vs. reactivation)
- Stress and strain
- Host-rock porosity
- Fluid migration
- Pore-fluid state

In addition to applying state-of-the-art existing data analysis techniques to data collected on the U.S. Navy permanent seismometer network, major aspects of the work have been:
• development of advanced software for monitoring microearthquakes on a continuing basis,
• the integration of this software into the existing system that monitors seismicity at Coso,
• development of interface software so the techniques can be applied on a routine basis, and
• installing and operating densification networks to improve monitoring of specific, local EGS experiments.

2.3.2 Microearthquake Monitoring

2.3.2.1 Permanent U.S. Navy seismometer network

Sensor Orientations
Determining earthquake mechanisms from seismic wave polarities and amplitude ratios requires data from three-component seismometers of known orientation. Unfortunately, the orientations of the permanent horizontal-component borehole seismometers at Coso initially were not well known. It is possible to estimate these orientations, however, by analyzing seismograms of \( P \) phases from local earthquakes. These are longitudinal waves, so their particle motion is in the ray directions, which can be predicted if the earthquake locations and the local structure are known. The particle-motion direction with respect to a sensor can be determined directly from multi-component seismograms, enabling the orientation of the sensor to be inferred.

In collaboration with personnel from the U.S. Navy, we used this method to determine the orientations of seismometers of the permanent network. Figure 2.38 shows an example result, for station NV2.
Figure 2.38: An example of determining seismometer orientation from P-phase amplitude measurements. Each circle shows the sensor orientation (azimuth of the “north” component) inferred from measurements from one earthquake, and the abscissa gives the earthquake-to-sensor azimuth. The data for waves coming from many directions lead to consistent inferred sensor orientations. A small systematic dependence on wave-propagation direction is caused primarily by local three-dimensional structure, not accounted for in this analysis.

This work led to the recognition that several sensors are wired incorrectly. Figure 2.39, for example, shows inferred sensor orientations for station NV5, which have extreme and systematic variations with the direction to the earthquake. Figure 2.40 shows the same data, analyzed under the assumption that the two horizontal components are interchanged. (Equivalently, one of the horizontal sensors could have its polarity reversed.) We have now entered information on sensor orientation and wiring as functions of time into a database, and corrections for these errors are made automatically during seismogram analysis. The detailed results are discussed in Section 2.3.2.2 (below).

Figure 2.39: Same as Figure 2.38, but for a sensor that is wired incorrectly. The inferred sensor orientation varies strongly and systematically with the direction to the earthquake. This variation is expected if one horizontal component has a reversed polarity, or equivalently if the two horizontal components are interchanged. See Figure 2.40.
Figure 2.40: Same as Figure 2.39, but assuming that the horizontal components are interchanged. Inferred sensor orientations are now consistent.

Real-Time Monitoring
To be most useful in monitoring an EGS experiment, processed seismological information (hypocenter locations and source mechanisms) should be available in near-real time. Currently, however, site visits are needed to collect data from the portable seismometer network at Coso, so processed data from these stations are available only after a delay of several days. Data from the permanent U.S. Navy seismometers are telemetered to China Lake in real time, but the software in use there requires human interaction in the earthquake location process, which imposes a delay in the availability of the results.

To reduce these delays, we implemented an “EarthWorm” system for real-time automatic processing of telemetered data during injection experiments. EarthWorm (http://folkworm.ceri.memphis.edu/ew-doc/) is a hardware/software facility developed by the USGS over the last 15 years and is widely used in many seismic networks throughout the world. EarthWorm automatically detects events in real time, saves digital waveforms, picks $P$-phase arrival times, and computes earthquake locations using conventional methods. A companion software facility, EarlyBird, maintains a data base of derived data, including earthquake catalogs, provides interactive tools for rapidly searching and accessing the data, and automatically generates alarms to notify key personnel of significant earthquakes and swarms.

We are currently developing the facility to add automatic high-resolution hypocenter- and source-mechanism determination (See Section 2.3.2.2, below) to EarthWorm.
2.3.2.2 Portable network

Determining full moment-tensor microearthquake mechanisms requires data from seismograms well distributed over the upper focal hemisphere (well distributed around the earthquakes). For earthquakes in the Coso southwest and east flank areas however, the U.S. Navy’s permanent seismometer network provides good coverage for only part of the upper hemisphere. In order to monitor the EGS experiment at wells in these areas, we collaborated with the U.S. Navy in deploying portable seismometers to supplement the permanent network to the east of the geothermal field.

Designing a geometrically optimal network requires knowledge of how the earthquake focal sphere is mapped onto the Earth’s surface by seismic rays. In designing the portable networks, we computed this mapping by numerically tracing seismic rays through three-dimensional models of upper-crustal structure of the Coso area, assuming that the earthquakes induced by the planned EGS experiments occur near the bottoms of the wells stimulated. We used the results to choose optimal seismometer locations.

We designed two different networks. The first, operated in 2004 and 2005, focused on the east flank area, to monitor earthquakes near well 34-9RD2. The second, which was not complete at the end of 2005, is focused on well 46A-19RD in the southwest part of the field. It was being installed at the time of writing (March, 2006).

East-Flank Deployment (Well 34-9RD2)

Figure 2.41 shows an example of mapping of the upper focal hemisphere onto the Earth’s surface for earthquakes in the east flank area at Coso. For a one-dimensional crustal model (i.e., wave-speed varying with depth only), the closed curves would comprise concentric circles and the radiating lines would be straight. The distortion of these circles and lines seen in Figure 2.41 results from refraction of the seismic waves by three-dimensional heterogeneities in the crust, and is analogous to the distortion of an image produced by light transmitted through a distorted lens.
Figure 2.41: Map showing the upper focal sphere of an earthquake, as projected onto the Earth’s surface along seismic rays computed using a three-dimensional crustal model for Coso (Wu and Lees, 1999). The earthquake in this example is located 3 km below the surface at well 34-9RD2. The outward-radiating curves are lines of constant take-off azimuth on the focal sphere, spaced 30° apart. The closed curves are lines of constant “incidence angle” i, measured from nadir, spaced 10° apart. Horizontally departing rays (i = 90°) extend off the map to the west and northeast. The small-scale complexity of the pattern for rays departing toward the south and southeast reflects the sensitivity of ray paths to structural details in the model, which are imperfectly known. Similarly, the simplicity of the pattern for rays to the northwest reflects a lack of structural information for that area in the model.

We used information like that shown in Figure 2.41 to choose optimal portable-seismometer locations. Figure 2.42 shows both networks, permanent and portable, that monitored the March 2005 EGS experiment at the east flank. Table 1 gives the sensor coordinates.
Figure 2.42: Seismometers at the Coso geothermal area at the end of 2005. Red lines: borehole traces; green squares: permanent seismometers of the Navy network; yellow triangles (B01, B02, B3-B5 and C1-C10): temporary portable seismometers deployed to improve coverage of earthquakes near well 34-9RD2. The U.S. Navy stations and portable stations B01 and B02 were continuously telemetered to China Lake. In some cases, portable instruments were moved to quieter sites; at most 16 portable sites were occupied at any one time. Data from two portable sites (B01 and B02) were telemetered to China Lake in real time. Data from other sites were recorded on computer disks deployed in the field and downloaded periodically.
### Table 1 – Seismometer Stations

<table>
<thead>
<tr>
<th>Code</th>
<th>Latitude</th>
<th>Longitude</th>
<th>Elevation (m)</th>
<th>Type†</th>
<th>Telemetry</th>
</tr>
</thead>
<tbody>
<tr>
<td>B01</td>
<td>36:02:34.36</td>
<td>-117:46:55.62</td>
<td>1161</td>
<td>T</td>
<td>Y</td>
</tr>
<tr>
<td>B02</td>
<td>36:02:30.65</td>
<td>-117:45:42.22</td>
<td>1091</td>
<td>T</td>
<td>Y</td>
</tr>
<tr>
<td>B3</td>
<td>36:01:39.15</td>
<td>-117:44:56.18</td>
<td>1068</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>B4</td>
<td>36:00:45.71</td>
<td>-117:46:16.19</td>
<td>1101</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>B5</td>
<td>36:01:42.07</td>
<td>-117:47:14.68</td>
<td>1220</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C1</td>
<td>36:04:00.16</td>
<td>-117:47:32.07</td>
<td>1550</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C10</td>
<td>36:02:53.43</td>
<td>-117:48:31.46</td>
<td>1337</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C2</td>
<td>36:03:56.24</td>
<td>-117:45:37.87</td>
<td>1157</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C3</td>
<td>36:03:37.95</td>
<td>-117:44:34.03</td>
<td>1149</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C4</td>
<td>36:02:22.47</td>
<td>-117:43:42.32</td>
<td>1267</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C5</td>
<td>36:01:20.27</td>
<td>-117:43:55.77</td>
<td>1213</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C6</td>
<td>35:59:33.76</td>
<td>-117:46:02.69</td>
<td>966</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C7</td>
<td>36:00:25.17</td>
<td>-117:47:24.48</td>
<td>1249</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C8</td>
<td>36:01:34.34</td>
<td>-117:48:54.51</td>
<td>1424</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C9</td>
<td>36:02:49.18</td>
<td>-117:48:24.00</td>
<td>1330</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>CE1</td>
<td>36:00:47.16</td>
<td>-117:48:09.00</td>
<td>1194</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>CE2</td>
<td>36:02:01.32</td>
<td>-117:47:17.88</td>
<td>1244</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>CE3</td>
<td>36:00:52.20</td>
<td>-117:49:11.28</td>
<td>1260</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>CE4</td>
<td>35:59:59.28</td>
<td>-117:48:08.28</td>
<td>1316</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>CE5</td>
<td>36:00:29.52</td>
<td>-117:45:51.12</td>
<td>1035</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>CE6</td>
<td>36:02:01.19</td>
<td>-117:46:21.81</td>
<td>1130</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>CE7</td>
<td>36:03:01.80</td>
<td>-117:48:16.56</td>
<td>1240</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>CE8</td>
<td>36:03:04.32</td>
<td>-117:50:19.32</td>
<td>1200</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NS10</td>
<td>35:59:56.60</td>
<td>-117:44:42.70</td>
<td>1060</td>
<td>T</td>
<td>Y</td>
</tr>
<tr>
<td>NS5</td>
<td>36:05:02.04</td>
<td>-117:45:12.96</td>
<td>1170</td>
<td>T</td>
<td>Y</td>
</tr>
<tr>
<td>NV1</td>
<td>35:58:57.72</td>
<td>-117:45:53.64</td>
<td>776</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NV10</td>
<td>35:59:56.60</td>
<td>-117:44:42.70</td>
<td>960</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NV2</td>
<td>36:01:31.80</td>
<td>-117:37:16.68</td>
<td>1551</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NV3</td>
<td>36:08:29.04</td>
<td>-117:41:15.36</td>
<td>1947</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NV4</td>
<td>36:02:51.72</td>
<td>-117:44:25.08</td>
<td>1103</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NV5</td>
<td>36:05:02.04</td>
<td>-117:45:12.96</td>
<td>1070</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NV6</td>
<td>35:58:56.28</td>
<td>-117:48:27.36</td>
<td>1439</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NV9</td>
<td>36:00:27.36</td>
<td>-117:45:05.40</td>
<td>1070</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>W1S</td>
<td>36:03:05.76</td>
<td>-117:59:44.52</td>
<td>1224</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>W2S</td>
<td>36:06:59.04</td>
<td>-118:00:11.16</td>
<td>1336</td>
<td>P</td>
<td>Y</td>
</tr>
</tbody>
</table>

† T: Temporary; P: Permanent
Southwest Deployment (Well 46A-19RD)

During 2006, an EGS experiment will take place at well 46A-19RD, in the southwestern part of the Coso field. This well is on the periphery of the permanent and east-flank networks, and furthermore is significantly deeper than the east-flank wells, so re-deploying several of the portable seismometers is necessary. In choosing new locations, we followed the same procedure described above, and traced rays through a three-dimensional crustal model to determine the best locations for additional, temporary stations. For this exercise, we were able to use a better crustal model, which we had derived as part of the tomography module of our work (see Section 2.3.4). Figure 2.43 shows the planned layout of the new network.

Figure 2.43: Planned layout of seismometers to monitor earthquakes near well 46A-19RD, shown in blue. Red lines: roads. Green squares: permanent seismometers of the U.S. Navy network. Yellow triangles: portable seismometers that will be retained. Red triangle: re-deployed portable seismometers. Black lines: Upper focal hemisphere for microearthquakes near the bottom of well 46A-19RD, as mapped onto the Earth’s surface by seismic rays. Theoretical rays computed from our three-dimensional tomographic model are spaced by 10° in “take-off angle” (measured from nadir) and 30° in azimuth.
2.3.3 Microearthquake Hypocenter Location

Although complete moment-tensor microearthquake mechanisms provide far more information than traditional fault-plane solutions do, including information about volume changes, that is important in geothermal monitoring, like fault-plane solutions, moment tensors are ambiguous and cannot uniquely identify the physical processes involved in earthquakes. It is thus critical to supplement moment tensors with additional information that can help identify these physical processes. Microearthquake hypocenter locations, if they are measured with high accuracy, can provide spatial images of seismic failure zones that are valuable for this purpose.

Traditionally, earthquakes are located individually, by fitting the arrival times of seismic waves at many seismometers. This method is subject to strong bias caused by wave-propagation effects in the incompletely known three-dimensional structure in the Earth. Recently developed methods greatly reduce this bias by fitting arrival-time differences and locating earthquakes relative to one another. Such methods yield accurate relative locations of nearby earthquakes, though they do not substantially improve absolute locations. A further substantial improvement, made by Waldhauser and Ellsworth (2000) involves simultaneously locating many (up to thousands) of earthquakes simultaneously, and greatly reduces the effects of random observational errors. Application of this method at other geothermal areas has demonstrated its usefulness in resolving seismically active geological structures, for example enabling us to distinguish tensile faults from shear faults at the Long Valley caldera, California, geothermal system (Foulger and others, 2004).

Figure 2.44 shows preliminary results of applying both kinds of methods to microearthquakes at Coso, using data from the permanent seismometer network recorded during injection experiments at well 51B-16 in September 2003. The Waldhauser-Ellsworth locations resolve microearthquake clusters near the injection well, as well as small northeast-southwest features in the general seismicity. The resolution is much better than single-event locations provide.
Figure 2.44: Comparison of conventional (above) and high-resolution (below) earthquake epicenters at Coso for September 2003, based on hand-measured times from the permanent U.S. Navy seismometer network. The high-resolution locations are more tightly clustered and resolve better northeast-southwest trends.
The existing implementation of the Waldhauser-Ellsworth method, the computer program hypoDD, can locate a large number of earthquakes simultaneously (up to about 10,000 on current computers), but suffers from several limitations:

- Limited speed and capacity
- Excessive memory requirements
- Inability to add earthquakes without re-processing the entire catalog
- Inability to improve the locations of diffuse earthquakes

A major effort of this project has been optimizing this algorithm and adapting it for studies of highly active areas such as Coso. The modified program, hypocc, is significantly faster and its earthquake-handling capacity is increased by an order of magnitude. It is also more flexible, and can be used to obtain high-resolution hypocenters of earthquakes as they happen, without the time-consuming necessity of relocating the entire catalog of events, which currently contains several tens of thousands of earthquakes. We will use this new program to locate microearthquakes during forthcoming hydraulic stimulation experiments at Coso in 2006. The hypocenters displayed on the web site http://cosomeq.wr.usgs.gov were computed using hypocc.

Although the Waldhauser-Ellsworth method can analyze hand-measured arrival times like those found in conventional earthquake catalogs, it performs best with relative arrival times measured by cross-correlating digital seismograms. The cross-correlation method uses the shapes of entire seismic waveforms, whereas hand-measured times use only their initial portions, which are of low amplitude and subject to large measurement errors. During 2004, we wrote software to make measurements of this kind using data from both the permanent and temporary Coso seismometer networks. Figure 2.45 shows results from applying this software to seismograms from the August 2004 injection experiment, and clearly illustrates its superiority over hand measurement.
Figure 2.45: Examples of measuring relative arrival times of seismic waves by cross-correlating digital seismograms. These vertical-component seismograms show P phases (the first-arriving waves) observed at portable station B01 from eleven earthquakes that occurred on 7 August 2004 near well 34A-9 during injection tests. The seismograms on the left are aligned by arrival times determined visually by a human analyst. On the right, the same seismograms are aligned using relative arrival times measured by waveform cross-correlation. The vertical lines are positioned arbitrarily and are provided as visual aids. The visually determined times (left) are based on the small high-frequency initial disturbances, which are highly variable from event to event and are sensitive to noise contamination. The cross-correlation times (right), in contrast, use the shape of the entire signal, and are more accurate and reliable. The improvement in alignment is obvious, for example between the third and fourth traces and between the bottom two traces. Each trace is about 0.26 seconds long, and consists of 0.13 seconds of signal plus about 0.13 seconds of zero padding. Relocation of the earthquakes using the arrival times determined using computer cross-correlation will reduce the relative location errors from 100s to 10s of meters.

2.3.4 Time-Dependent Seismic Tomography

2.3.4.1 Acquisition and selection of initial data

Earthquake location catalog files and arrival time measurement files for each year 1992 – 2004 inclusive were downloaded from the U.S. Navy database over the Internet. The earthquake location catalog files contain, for each earthquake, the calculated time of occurrence, latitude, longitude, depth below the surface, root-mean-square (RMS) arrival time residual, azimuthal
gap, number of $P$- and $S$-phase arrival time measurements used in the location, and auxiliary data. There is one arrival-time measurement file for each earthquake. These files contain the measured arrival-times of $P$- and $S$-phases at each station at which the earthquake was recorded well, along with codes that indicate the analyst-judged quality of each measurement.

Data for the years 1992 - 1995 suffered from various problems, including poor location quality as a result of early, lesser quality of the seismic network, and complexities in the data archive. As a result, we concentrated on the data from years 1996 - 2004. The seismic stations at the Coso geothermal area were located by U.S. Navy personnel using DGPS (differential GPS) and the locations are accurate to a few tens of meters. These station locations were provided by Dr. Keith Richards-Dinger at the U.S. Navy.

The earthquakes are clustered in the center of the network, which is also the most intensely exploited part of the geothermal area. The total annual numbers of earthquakes in the U.S. Navy catalogs are given in Table 2.

**Table 2 – Total Numbers of Earthquakes in each Year in U.S. Navy Catalog**

<table>
<thead>
<tr>
<th>Year</th>
<th>Number of earthquakes</th>
</tr>
</thead>
<tbody>
<tr>
<td>1992</td>
<td>4,896</td>
</tr>
<tr>
<td>1993</td>
<td>5,461</td>
</tr>
<tr>
<td>1994</td>
<td>3,570</td>
</tr>
<tr>
<td>1995</td>
<td>4,500</td>
</tr>
<tr>
<td>1996</td>
<td>5,606</td>
</tr>
<tr>
<td>1997</td>
<td>4,003</td>
</tr>
<tr>
<td>1998</td>
<td>6,651</td>
</tr>
<tr>
<td>1999</td>
<td>8,439</td>
</tr>
<tr>
<td>2000</td>
<td>9,947</td>
</tr>
<tr>
<td>2001</td>
<td>5,140</td>
</tr>
<tr>
<td>2002</td>
<td>6,504</td>
</tr>
<tr>
<td>2003</td>
<td>5,025</td>
</tr>
<tr>
<td>2004</td>
<td>12,653</td>
</tr>
</tbody>
</table>

The entire earthquake data set contains many poorly recorded events that degrade data quality. A subset of the best events, which are suitable for tomographic inversions, was thus selected. Several different quality measures were used in this selection process, including the number of arrival times, root-mean-square arrival time and azimuthal gap. The numbers of earthquakes that passed these quality control tests are shown in Table 3, and the distribution of epicenters for the six years 1998 - 2003 are shown in Figure 2.46.

**Table 3 – Numbers of Earthquakes that Passed Quality-Control Tests**
<table>
<thead>
<tr>
<th>Year</th>
<th>Number of earthquakes</th>
</tr>
</thead>
<tbody>
<tr>
<td>1992</td>
<td>881</td>
</tr>
<tr>
<td>1993</td>
<td>610</td>
</tr>
<tr>
<td>1994</td>
<td>1,489</td>
</tr>
<tr>
<td>1995</td>
<td>2,220</td>
</tr>
<tr>
<td>1996</td>
<td>1,904</td>
</tr>
<tr>
<td>1997</td>
<td>1,427</td>
</tr>
<tr>
<td>1998</td>
<td>2,277</td>
</tr>
<tr>
<td>1999</td>
<td>4,350</td>
</tr>
<tr>
<td>2000</td>
<td>4,368</td>
</tr>
<tr>
<td>2001</td>
<td>575</td>
</tr>
<tr>
<td>2002</td>
<td>1,894</td>
</tr>
<tr>
<td>2003</td>
<td>1,500</td>
</tr>
<tr>
<td>2004</td>
<td>6,127</td>
</tr>
</tbody>
</table>
Figure 2.46  Map of the Coso geothermal area showing locations of all earthquakes from the U.S. Navy earthquake location catalog files that occurred in the years 1998 – 2003 and passed the quality control tests. Seismic stations (green triangles) are also shown.
Additional filters were applied to winnow the data sets to optimize their suitability for tomographic inversion. For inversions for areas on the scale of the Coso geothermal area, a suitable number of earthquakes is a few hundred. This keeps program run times down to a practical level (less than ~ 1 hour per run) while yielding good structural resolution. We thus extracted from the sets of earthquakes that passed the quality control test, candidate subsets of a few hundred for each year that were well distributed throughout the target volume.

Earthquakes that were well outside the study area were rejected since long portions of the ray paths of such events lie outside the modeled volume. If they are included, structure outside of the volume of interest may be projected into the final inversion result. The area within which earthquakes were selected extended to an additional 2 km outside the main study area, this being both acceptable for the final three-dimensional tomography inversions and desirable in the case of this project, where many high-quality earthquakes lay just outside the geothermal area. The whole area was then subdivided into 196 squares, each 1 x 1 km in area. If a square contained fewer than 10 earthquakes, they were all selected, but if a square contained more than 10 earthquakes, they were ranked according to quality and the best 10 only were used.

### 2.3.4.2 Inversion for best one-dimensional structure

The program velest (v3.3) (Kissling and others, 1994) inverts earthquake travel-time data for a model parameterized as a stack of homogeneous layers. It is useful both in its own right and it provides the best a priori starting model for three-dimensional tomography.

As a starting model for velest, a crustal model calculated by E. Shalev (Sondi & consultants`; Shalev, 1994) was used. That model extends only to a depth of 2 km b.s.l., which is inadequate for the present work since the seismically active depth range may extend as deep as ~8 km b.s.l. It was thus extrapolated downward, yielding velocities similar to those currently used by the U.S. Navy for their routine earthquake location work.

Many inversions were performed using velest in order to explore parameter space and converge on the global minimum in the data. The integrity of the data was re-examined at various stages to eliminate outliers. Final inversions both with and without station corrections were performed for each of the 7 years 1997 – 2003 separately. The final RMS arrival-time residuals were in the range 0.031 - 0.048 s for inversions with station corrections, and 0.048 - 0.069 s for inversions without station corrections. This is to be expected, since the inversions with station corrections involved 49 free parameters compared with only 20 in the case of inversions without station corrections. The final numbers of earthquakes used for each year are given in Table 4.
Table 4 – Numbers of Earthquakes Used for Final velest Inversions

<table>
<thead>
<tr>
<th>Year</th>
<th>#eqs</th>
</tr>
</thead>
<tbody>
<tr>
<td>1997</td>
<td>504</td>
</tr>
<tr>
<td>1998</td>
<td>648</td>
</tr>
<tr>
<td>1999</td>
<td>742</td>
</tr>
<tr>
<td>2000</td>
<td>724</td>
</tr>
<tr>
<td>2001</td>
<td>735</td>
</tr>
<tr>
<td>2002</td>
<td>691</td>
</tr>
<tr>
<td>2003</td>
<td>801</td>
</tr>
</tbody>
</table>

The final results for \(V_P\), \(V_S\) and \(V_P/V_S\) are shown graphically in Figures 2.47a,b,c. Most of the final models are similar. Final \(V_P\) and \(V_S\) models (from which \(V_P/V_S\) models were calculated) were obtained by fitting smooth profiles to the bundles of models in the suites of final inversions, ignoring the result for \(V_P\) from 2001 without station corrections which was somewhat different from the others for reasons not well understood. The final models are shown by red triangles in Figures 2.47a,b,c and numerically in Table 5.
Figure 2.47a  Crustal structure results from final velest inversions; $V_p$. “w/ STs” signifies with station corrections, “w/o STs” signifies without stations corrections. Green triangles indicate the updated starting model obtained from preliminary inversions and the red triangles indicate the final one-dimensional model estimated by averaging by eye the results of the individual inversions. Note that there is a 1.5-km offset in depth, which was required to overcome technical restrictions in velest.
As Figure 2.47a but for $V_s$. 

Figure 2.47b
Figure 2.47c  As Figure 2.47a but for $V_p/V_s$. 

Coso velest $V_p/V_s$ models
Table 5 shows the final, numerical one-dimensional structural results, corrected for the temporary 1.5-km shift that was used during the calculations.

**Table 5 – Final Velocity Model with 1.5-km Shift Removed**

<table>
<thead>
<tr>
<th>Depth to top of layer, km b.s.l.</th>
<th>(V_P)</th>
<th>(V_S)</th>
<th>(V_P/V_S)</th>
</tr>
</thead>
<tbody>
<tr>
<td>-2.0</td>
<td>4.35</td>
<td>2.51</td>
<td>1.733</td>
</tr>
<tr>
<td>-1.5</td>
<td>4.55</td>
<td>2.56</td>
<td>1.777</td>
</tr>
<tr>
<td>-1.0</td>
<td>4.95</td>
<td>2.78</td>
<td>1.781</td>
</tr>
<tr>
<td>0.0</td>
<td>5.37</td>
<td>3.05</td>
<td>1.761</td>
</tr>
<tr>
<td>1.0</td>
<td>5.71</td>
<td>3.29</td>
<td>1.736</td>
</tr>
<tr>
<td>2.0</td>
<td>5.76</td>
<td>3.36</td>
<td>1.714</td>
</tr>
<tr>
<td>3.0</td>
<td>5.81</td>
<td>3.42</td>
<td>1.699</td>
</tr>
<tr>
<td>4.0</td>
<td>5.82</td>
<td>3.49</td>
<td>1.668</td>
</tr>
<tr>
<td>6.0</td>
<td>5.82</td>
<td>3.49</td>
<td>1.668</td>
</tr>
<tr>
<td>8.0</td>
<td>5.82</td>
<td>3.49</td>
<td>1.668</td>
</tr>
</tbody>
</table>

Wave speeds determined for \(V_P\) for the upper 2 km were slightly (as much as 0.12 km/s) lower than those obtained by Shalev et al. (1994) and currently used by the U.S. Navy for routine locations. Beneath this, the wave speeds obtained were substantially (up to 0.24 km/s) higher. A similar result was obtained for \(V_S\). A typical crustal value for \(V_P/V_S\) is 1.74. The average value obtained for the Coso area is 1.70. Beneath the shallowest level \(V_P/V_S\) increases to a maximum of 1.78.

The top ~ 2 km of the producing reservoir is characterized by \(V_P/V_S\) higher than 1.74. Beneath sea level an inversion occurs and values as low as 1.67 occur in the deepest levels sampled, which are at 4 – 8 km b.s.l. It is not clear what the geological significance of this is. It is most likely related to petrology since most geothermal processes of the kind likely to be occurring at Coso e.g., increase in steam content in pore fluids, are expected to decrease \(V_P/V_S\).

### 2.3.4.3 Inversion for best three-dimensional structure

The area chosen for imaging is a north-orientated square, 10 km on a side, with its northwest corner at 36˚N04.10706’, 117˚W50.65611’ and its southeast corner at 35˚N58.70000’, 117˚W44.00000’ (Figure 2.48). This area is 100 km\(^2\) in size and includes 13 of the 18 seismic stations of the U.S. Navy permanent network.

The program *simul2000A* (Evans and others, 1994; Thurber, 1983) was used to invert the data. This program uses a scheme where the compressional- and shear-wave speeds, \(V_P\) and \(V_S\), are parameterized by their values at nodes located at the intersections of orthogonal planes spaced at intervals of 2 km (or 1 km) horizontally and 1 km vertically. Nodes extend from 2 km above sea level (a.s.l.) to 10 km b.s.l. In this report we show structure only from 1 km a.s.l down to 4 km b.s.l. where the wave speeds are well determined. *simul2000A* uses an iterative, damped-least-
squares method to invert arrival times, simultaneously estimating earthquake locations and the three-dimensional $V_p$ and $V_p/V_S$ fields.

Data from years 1996 - 2004 were inverted. 1996 was the earliest year for which the seismic network, data collection and processing system at the U.S. Navy base at China Lake were stable and data throughout the year may be assumed to be of uniform quality and in a uniform format.

Figure 2.48 Map showing the square grid that encloses the area selected for the three-dimensional tomographic inversion. Red lines indicate the surface traces of geothermal boreholes, and green triangles indicate seismic stations.
Standard practice was in general followed. This involved starting with the one-dimensional model determined using velest and inverting the data on a grid with 2-km nodal spacings. The resulting 3-dimensional structure was interpolated to 1-km nodal spacings, and this model was used as a starting model to re-invert the data on a grid with 1-km nodal spacings. Damping values were chosen on the basis of “damping trade-off curves” (Evans and Achauer, 1993). In order to construct these, suites of one-iteration “damping” inversions were conducted with damping values set successively at 999, 100, 50, 20, 10, 5, 2, 1 and 0.1. Curves of data variance: model variance (“damping trade-off curves”) were then constructed for the inversion suite. The optimal damping value was the one that gave the largest data variance reduction. This method was used to select both $V_P$ and $V_P/V_S$ damping values. A detailed description of the inversion procedure is given in Foulger & Julian (2006).

The entire tomography work module involved performing some 500 inversions.

In order to obtain the best possible average three-dimensional structural model for the entire time period studied here (1996 - 2004) a large number of earthquake arrival times drawn from years 1997 - 2003 were combined in a data set named “AllData”. The data set comprised 4811 earthquakes, and a total of 79,822 $P$ and $S$ travel times. In order to study changes in structure from year to year, that might be cause by production, independent inversions were also conducted for each of the years 1996 – 2004 separately. The numbers of earthquakes used for each individual year are shown in Table 6.

**Table 6 – Numbers of Earthquakes Used for the Final simul2000A Inversions**

<table>
<thead>
<tr>
<th>Year</th>
<th>#eqs</th>
</tr>
</thead>
<tbody>
<tr>
<td>1996</td>
<td>496</td>
</tr>
<tr>
<td>1997</td>
<td>502</td>
</tr>
<tr>
<td>1998</td>
<td>638</td>
</tr>
<tr>
<td>1999</td>
<td>742</td>
</tr>
<tr>
<td>2000</td>
<td>724</td>
</tr>
<tr>
<td>2001</td>
<td>734</td>
</tr>
<tr>
<td>2002</td>
<td>650</td>
</tr>
<tr>
<td>2003</td>
<td>777</td>
</tr>
<tr>
<td>2004</td>
<td>906</td>
</tr>
</tbody>
</table>

The preferred results for the entire data set are those obtained on a grid with 2-km nodal spacing (Figure 2.49). These results may be considered to provide the best representation of the average three-dimensional structure of the Coso area for the period 1997 - 2003. Major anomalies that correlate with geological, morphological and geothermal features include a major negative $V_P$ and $V_S$ anomaly with a bipartite, hourglass shape in the east of the area extending throughout the depth slices –1 and 0 km b.s.l. This anomaly correlates closely with the Coso Wash and probably represents sedimentary valley fill. The results suggest that this valley extends from the surface to at least sea level in its northern part (the upper Coso Wash area) and at least to 1 km b.s.l, in its southern part (Coso Basin). Its vertical extent is thus 2-3 km beneath the upper Coso Wash area and 3-4 km beneath Coso Basin. This could be further studied using gravity modeling.
An anomaly of similar sign and depth extent is visible at −1 km b.s.l. in the northwest of the area. The central part of the entire area has average or high wave speeds except towards the bottom of the well-resolved volume, in the depth slice at 2 km b.s.l., where there is some evidence for a low- $V_p$, low- $V_S$ region.

The $V_p/V_S$ field shows a major negative $V_p/V_S$ anomaly at −1 km b.s.l. that correlates very closely with the geothermal well-field north of the latitude of seismic stations CE3 and CE1 (Figure 2.49). The well-field south of this latitude is characterized by high $V_p/V_S$ values at −1 km b.s.l. At sea level and deeper the shape of the $V_p/V_S$ anomaly changes. It becomes weaker and extends beneath the southern part of the well-field and is less extensive beneath the eastern part. At 1 km b.s.l. it is restricted in lateral extent and occupies a small area northeast of the well-field only. Below this, at 2 km b.s.l. a negative $V_p/V_S$ anomaly of larger extent underlies the east flank region, approximately beneath the saddle between the upper Coso Wash area and Coso Basin.

The negative $V_p/V_S$ anomaly that correlates with the geothermal field is characterized by high $V_p$ but even higher $V_S$. Thus it results from anomalously high $V_S$ rather than anomalously low $V_p$.

All the major features observed in the 2-km nodal spacing inversion, and described above, were also seen in the 1-km nodal spacing results. More fine detail is apparent in those results, however, and numerous smaller anomalies, along with higher amplitudes for some anomalies. The final weighted RMS arrival time for this inversion was only slightly lower than for the 2-km-nodal-spacing inversion, however, suggesting that little additional signal in the data is explained by the significantly more complex 1-km result.
Figure 2.49 The preferred results for the entire data set, obtained using a grid with 2-km nodal spacings and data from the period 1997 – 2003.
The objective of inverting each year separately was to investigate possible changes in structure with time that might be related to geothermal operations. Of particular interest is the negative $V_P/V_S$ anomaly that correlates with the geothermal field (Figure 2.49) which might be related to production. This anomaly, in the shallowest two depth sections at 1 and 2 km below surface, strengthened overall throughout the period 1996 – 2004 (Figure 2.50). The strengthening is irregular from year to year. This result may be compared with results from The Geysers geothermal field. There, a clear strengthening of a negative $V_P/V_S$ anomaly associated with steam extraction was detectable in inversions of data collected at 2-year intervals 1991 – 1998 (Gunasekera and others, 2003). During this period steam production was 7 - 9 x $10^{10}$ kg/yr (Barker and others, 1992). In comparison, fluid extraction from the Coso geothermal field for the period 1996 – 2004 has been fairly steady and approximately 4 x $10^{10}$ kg/yr, along with injection at a steady rate of approximately 2 x $10^{10}$ kg/yr. The net fluid loss rate is thus approximately 2 x $10^{10}$ kg/yr.

The fluid extraction rate at the Coso geothermal field is approximately half that at The Geysers, suggesting that, if all else were equal, significant growth of the negative $V_P/V_S$ anomaly on a time-scale of ~4 years might be expected. The effect of reinjection on structural change in geothermal reservoirs has not to date been studied anywhere, but it might be expected that if the injected fluid either contributes to the fluid extracted, or replenishes depleted regions of the reservoir, then the net fluid loss rate is the appropriate figure to consider in estimating the likely time-scales over which reservoir structure might significantly change seismically. If so, and the net fluid extraction rate is approximately 2 x $10^{10}$ kg/yr, it might be expected that clearly detectable changes would occur on a time scale of ~ 10 years.

Careful examination of Figure 2.50 shows that the negative $V_P/V_S$ anomaly is stronger in the last few years of the nine-year time period studied, compared with the first few years. This suggests qualitatively that the Coso geothermal field is behaving in a similar way to The Geysers field, but at a lower rate as a result of the much lower net fluid loss rate achieved by more modest production and significant reinjection.

The negative $V_P/V_S$ anomalies are associated with high and increasing $V_P$ and $V_S$, but $V_S$ increases at a greater rate than $V_P$. Processes expected to be associated with geothermal operations that can increase the value of $V_S$ compared with $V_P$ include a) steam flooding which lowers $V_P$ more than $V_S$ by increasing the compressibility of the pore fluid, b) decrease in fluid pressure, which raises $V_S$ more than $V_P$, and c) the drying of certain argillaceous minerals such as illite (Figure 2.51). All of these factors indicate reservoir fluid depletion, but only the latter two involve increases in the wave speeds. The temporal changes observed are thus consistent with pressure decrease and mineral drying in the reservoir, but not the replacement of liquid pore fluid with steam, unless this effect is camouflaged by stronger wave-speed increases caused by the other two processes. Precise determination of the exact processes at work requires detailed comparison of the results with operation history.
Figure 2.50  
Results for individual years separately, nodal spacing: 2 km.
Figure 2.51  Schematic figure illustrating the effects of processes caused by exploitation on $V_P$, $V_S$ and $V_P/V_S$. Long arrows indicate the dominant effect, and short arrows indicate subsidiary effects. The three processes have differing effects on $V_P$ and $V_S$ but all cause $V_P/V_S$ to decrease.

2.3.4.4  **Summary of time-dependent tomography results**

1. Compared with the crustal model currently used by the U.S. Navy for their routine earthquake locations, the average one-dimensional crustal structure of the Coso area determined in this project using velest features somewhat lower wave speeds at shallow depth and significantly higher ones at greater depth. Use of a model with higher wave speeds in general will typically result in shallower earthquake hypocentres being calculated.

2. The area is characterized by relatively high $V_P/V_S$ in the upper ~4 km, beneath which it is relatively low. This might be due to petrological variations.

3. Inversions of a 4811-earthquake data set comprising 79,822 P and S travel times at the 2-km-nodal-spacing level revealed low $V_P$ and $V_S$ wave speeds associated with fill in the Coso Wash extending to a depth of 2-3 km beneath the upper Coso Wash area and 3-4 km beneath Coso Basin. A $V_P/V_S$ low occupies the northern and eastern part of the geothermal field at ~1 km b.s.l., and the northern and southern parts of the field at sea level.

4. Independent inversions for each of the years 1996 - 2004 separately show an irregular strengthening in the negative $V_P/V_S$ anomalies at ~1 km b.s.l. and at sea level. This progressive reduction in $V_P/V_S$ results predominately from the progressive relative increase of $V_S$ with respect to $V_P$. Such a progressive increase is expected to result from processes
associated with geothermal operations such as decrease in fluid pressure and the drying of argillaceous minerals such as illite.

2.3.5 Earthquake Moment Tensors

2.3.5.1 Objectives of moment tensor analysis

Traditional fault plane solutions for earthquakes constrain motion normal to fault planes to be zero. Whereas this approach may be an adequate approximation for first-order studies in many shear-faulting regions, it is inappropriate for analysis of geothermal earthquakes. There, the involvement of fluids results in the opening and closing of underground faults and cavities to be the norm. It is necessary to resolve those components if the maximum information relevant to fluid flow is to be obtained from geothermal earthquakes. This information can only be obtained by inverting seismic data for complete moment tensors, which contain information on motions at the source in all three Cartesian directions.

Good moment tensors require a seismometer network that provides a good distribution of high-quality, calibrated, three-component stations surrounding the earthquakes of interest. As described above, in order to achieve this for the EGS experiments at the Coso geothermal area, the U.S. Navy network was supplemented with additional temporary stations. This network increased the station coverage, in particular in the neighborhood of planned injection experiment on the east flank.

In addition to major software development described in Section 2.3.7.3, moment tensor work focused on determination of seismic parameters associated with microearthquakes induced by injection into well 34-9RD2 on the east flank of the Coso geothermal area. This injection experiment was a primary experiment of the Enhanced Geothermal Systems (EGS) project. The location of well 34-9RD2 in the study area is shown in Figure 2.52.
Figure 2.52: Map showing wells of the east flank of the Coso Geothermal area, including well 34-9RD2 that was stimulated in the EGS experiment.

2.3.5.2 Sensor polarities and orientations

As for traditional fault plane solutions, the polarities of the vertical seismometer components are required. In addition, the orientations of the horizontal (“North” and “East”) components of the three-component stations are required. It proved to be a major task to assemble a reliable set of these data for the networks for the following reasons:

- The 22 permanent U.S. Navy stations are mostly in boreholes and thus the orientations of the horizontal components could not be measured directly in the field.

- These stations have been in place for a number of years and thus have a complex history of maintenance, and polarities and orientations may have changed with time.

- It was standard practice when deploying the temporary network stations to orient the “North” component to magnetic north using a compass. However, this was not always done, e.g., if the field party forgot to take a compass.
It transpired that some of the sensors used for the portable network stations were wired up wrongly (Section 2.3.2.1). Pathologies included the “North” and “East” components being swapped, and components being reversed (e.g., “East” being really “West”).

Polarity and orientation data were assembled using a number of methods which included:

- Inherited, earlier information from the permanent network,
- Tapping or dropping weights vertically onto the surface sensors, including portable network sensors,
- Studying suites of fault-plane solutions to determine if individual stations appeared to have consistent normal or reversed responses,
- Studying the response of horizontal sensor components to earthquake waves arriving from known azimuths,
- Studying the directions and amplitudes of first arrivals recorded from a blast fired April 6th 2005

For the three-year period 2003 - 2005 inclusive, the situation was complicated further by the possibility that the polarities and orientations of sensors at individual stations had changed during this period. The best data set available for March 2005 is given in Table 7.
### Table 7 – Polarities of Vertical Sensors and Orientations of Horizontal Sensors of Stations of U.S. Navy Permanent and Temporary Network Stations for March 2005

**Injection 3**
22nd Feb – 4th March, 2005
day 053-063

<table>
<thead>
<tr>
<th>Inj3 sensor</th>
<th>Inj3.polarity file</th>
<th>Orient’n of N compt</th>
</tr>
</thead>
</table>

#### Permanent stations

<table>
<thead>
<tr>
<th>Station</th>
<th>Injection</th>
<th>Orientation</th>
</tr>
</thead>
<tbody>
<tr>
<td>B01</td>
<td>-1</td>
<td>mag N</td>
</tr>
<tr>
<td>B02</td>
<td>L22</td>
<td>not known</td>
</tr>
<tr>
<td>CE1</td>
<td>-1</td>
<td>154</td>
</tr>
<tr>
<td>CE2</td>
<td>-1</td>
<td>198</td>
</tr>
<tr>
<td>CE3</td>
<td>-1</td>
<td>E compt bad</td>
</tr>
<tr>
<td>CE4</td>
<td>-1 (uncertain)</td>
<td>253</td>
</tr>
<tr>
<td>CE5</td>
<td>defunct</td>
<td>defunct</td>
</tr>
<tr>
<td>CE6</td>
<td>bad vertical</td>
<td>not known</td>
</tr>
<tr>
<td>CE7</td>
<td>-1</td>
<td>56</td>
</tr>
<tr>
<td>CE8</td>
<td>+1 (uncertain)</td>
<td>113 (uncertain)</td>
</tr>
<tr>
<td>NV10</td>
<td>not known</td>
<td>55</td>
</tr>
<tr>
<td>NS10</td>
<td>L22</td>
<td>93R</td>
</tr>
<tr>
<td>NV1</td>
<td>-1</td>
<td>49</td>
</tr>
<tr>
<td>NV2</td>
<td>+1</td>
<td>230</td>
</tr>
<tr>
<td>NV3</td>
<td>+1</td>
<td>303R</td>
</tr>
<tr>
<td>NV4</td>
<td>+1</td>
<td>51R</td>
</tr>
<tr>
<td>NV5</td>
<td>+1</td>
<td>77R</td>
</tr>
<tr>
<td>NS5</td>
<td>L22</td>
<td>80R</td>
</tr>
<tr>
<td>NV6</td>
<td>+1</td>
<td>10R</td>
</tr>
<tr>
<td>NV9</td>
<td>defunct</td>
<td>defunct</td>
</tr>
<tr>
<td>W1S</td>
<td>-1</td>
<td>209</td>
</tr>
<tr>
<td>W2S</td>
<td>+1</td>
<td>not known</td>
</tr>
</tbody>
</table>

**R = east component reversed**

#### Portable stations

<table>
<thead>
<tr>
<th>Station</th>
<th>Injection</th>
<th>Orientation</th>
</tr>
</thead>
<tbody>
<tr>
<td>B3</td>
<td>L22</td>
<td>-1 mag N+11˚</td>
</tr>
<tr>
<td>B4</td>
<td>L22</td>
<td>+1 mag N+13˚</td>
</tr>
<tr>
<td>B5</td>
<td>CMG3</td>
<td>+1 mag N</td>
</tr>
<tr>
<td>C1</td>
<td>L22</td>
<td>-1 mag N</td>
</tr>
<tr>
<td>C2</td>
<td></td>
<td>-1 mag N</td>
</tr>
<tr>
<td>C3</td>
<td></td>
<td>-1 mag N</td>
</tr>
<tr>
<td>C4</td>
<td>L22</td>
<td>-1 mag N</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>---</td>
<td>---</td>
<td>---------------</td>
</tr>
<tr>
<td>C5</td>
<td></td>
<td>CMG3</td>
</tr>
<tr>
<td>C6</td>
<td>+1</td>
<td>mag N</td>
</tr>
<tr>
<td>C7</td>
<td></td>
<td>mag N</td>
</tr>
<tr>
<td>C8</td>
<td>L22</td>
<td>mag N</td>
</tr>
<tr>
<td>C9</td>
<td></td>
<td>not operating</td>
</tr>
<tr>
<td>C10</td>
<td>L22</td>
<td>mag N</td>
</tr>
<tr>
<td>C11</td>
<td>Geospace</td>
<td>mag N</td>
</tr>
<tr>
<td>C12</td>
<td></td>
<td>mag N</td>
</tr>
</tbody>
</table>
2.3.5.3 Results

The quality of data recorded by the two networks was excellent. In particular the sensors of the permanent network installed in boreholes yielded impulsive P- and S-wave arrivals with little noise (Figure 2.53).

![Seismic Data](image)

**Figure 2.53:** 2 minutes of excellent, 3-component seismic data recorded at the U.S. Navy borehole seismometer CE1. Note the superb quality of S-wave arrivals, that enable excellent P:S-wave amplitude ratios to be measured and provide strong constraints on the moment tensors.

Moment tensors were obtained for a number of well-recorded earthquakes that occurred on the east flank, March 2005. The P-, SH- and SV-polarities, and P:SH and SH:SV amplitude ratio fields are shown for six examples in Figure 2.54.
22/20050222193415  FEASIBLE (L1 = -2.26311e-07)

22/20050222193443  OPTIMAL (L1 = 0.0899804)

03/20050303030743  OPTIMAL (L1 = 0.0237064)
Figure 2.54. Summary of the results for six well-recorded earthquakes that occurred on the east flank in March 2005. All circles represent upper focal sphere equal-area projections. For each earthquake, the upper three circles show P, SH and SV polarity plots, along with the best-fit nodal (zero P-wave amplitude) lines. Positive P-wave motion is outward, positive SH motion is to the right (clockwise) as viewed from above the source, and positive SV motion is upwards (towards the zenith). Positive motions are shown as filled circles, and negative motions as open circles. Squares represent down-
going rays plotted at the antipodal point on the upper focal hemisphere. Lower two circles: P:SH and SH:SV ratios, displayed using the convention shown in Figure A3 (Julian and Foulger, 1996).

Good moment tensors were obtained for a total of 38 earthquakes prior to, during, and following the March 2005 injection experiment. The earthquakes showed predominately volume increases, consistent with the opening of cracks and cavities in response to the injection of fluid into the formation beneath the East Flank. A full interpretation, joint with the results of relative relocations, is given below in Section 2.3.6.

2.3.6 The EGS Experiment in Well 34-9RD2: Integrated Interpretation

2.3.6.1 Background

Injection of fluids into critically stressed rock, or induction of such stress by injection under pressure, has the potential to create new cracks or extend pre-existing ones through the process of hydraulic fracture. This process is seismogenic and results in swarms of earthquakes caused by the breaking of rock along the flow path of the injected fluids. Analyzing these earthquakes is essentially the only way to obtain detailed information about the orientation of the cracks stimulated, their dimensions and mode of failure, and thus the immediate trajectory of the injected fluids once they leave the borehole. Information may also be obtained about the stress cycle accompanying the injection, i.e., stress before, during and following the injection. This information relates to the longer-term effects of the injection.

Traditional microearthquake analyses yield only a general picture of the effects of fluid injection. Standard earthquake locations are typically only accurate relative to one another at the level of hundreds of meters – many hundreds of meters for poor seismometer networks or a few for high-quality networks such as that operated at Coso. Locating injection-related earthquake sequences with such methods typically yields diffuse clouds of locations that may give some idea of the direction in which the fluids migrated, but little in the way of precise detail of the orientation of the permeability zone stimulated. There may also be systematic errors if a one-dimensional crustal model only is used. Likewise, traditional fault-plane analysis of earthquake mechanisms gives only a rough picture of the orientation of fractures stimulated (it cannot constrain volumetric components, i.e., crack opening or closure) and the local stress field.

We used a powerful combination of new techniques to study the injection test performed in well 34-9RD2 in March 2005. We calculated accurate relative hypocenter locations using hypocc (Section 2.3.2.1) along with highly accurate moment tensors for the largest earthquakes. We used a rich data set from stations both of the permanent U.S. Navy network and the temporary network (Section 2.3.2.2). By combining both types of result we were able to greatly reduce ambiguity concerning the orientation and mode of failure of the fractures stimulated. This module of work was highly successful, and it comprised a unique study and a proof of concept of the method.
2.3.6.2 History of the injection test

The EGS injector well 34-9RD2 was reworked, drilled and stimulated February - March 2005. Massive mud losses started late March 2nd, indicating that the drilling mud had been lost into the formation near the bottom of the well at ~2,660 m depth. Although this event had not been planned, it nevertheless comprised an injection, albeit of drilling mud rather than water as had been planned initially.

The mud injection stimulated considerable seismicity. Of the large, well-recorded earthquakes that were successfully processed, the first that might be associated with the injection operation occurred 2nd March, 22:20 hrs and had a magnitude of M 0.5. Including this earthquake, a total of 7 were successfully processed in the period 2nd March 22:20 - 3rd March 01:25.

Starting 3rd March, 03:07 hrs, an intense swarm of earthquakes occurred, the largest of which had a magnitude of M 2.6 (Figure 2.55) and was felt by personnel at the well head. This swarm lasted ~ 50 minutes, but most of the largest earthquakes occurred in the first 2 minutes (Figure 2.55). Earthquakes as small as magnitude M 0.3 were located. Two rotatable 3D views of the microearthquake locations are available at the password-protected web site http://cosomeq.wr.usgs.gov.
Figure 2.55: Magnitude-time plot for 1st - 29th March 2005. Each UTC day begins at the axis tick. Seismicity associated with the injection of drilling mud started about 23:00 UTC (14:00 PST) on March 2nd. The ticks on the lower plot are one hour apart.

The earthquakes selected for study were those that occurred during the month of March 2005 and whose epicenters lay within 1 km of the seismic station CE6, which was near to the head of well 34-9RD2 (Figure 2.56). The entire data set examined contained 204 earthquakes, of which a subset of the highest quality gave good relative relocations and moment tensors.

Figure 2.56: Map of the Coso geothermal area showing seismometer networks (green symbols), surface projections of wells (red lines). Earthquakes that occurred during March 2005 and whose epicenters lay within the blue circle were selected for study.
2.3.6.3 Relative relocation results

The results of relatively relocating the injection-related earthquakes are shown in Figure 2.57. The left panel shows locations from the U.S. Navy catalogue. These locations were obtained by processing each earthquake separately (Section 2.3.2.2). The locations form a diffuse cluster and little structure can be discerned. Furthermore, they are mostly located at or just below sea level (indicated by the intersection of the N, E and Down axes).

The right panel shows the relative relocations. Because of the nature of the calculations, only a subset of the best-recorded earthquakes are successfully relocated. More structure can be seen than in the U.S. Navy routine locations (right panel) and this is particularly clearly seen in the rotatable 3-D plots available on the website. The diagrams shown in Figure 2.58 are orientated in order to show best that the swarm earthquakes (plotted in yellow) delineate a plane, i.e. their distribution extends in and out of the plane of the page.

![Figure 2.57](image)

*Figure 2.57: Three-dimensional depiction of earthquake hypocenters. Green: pre-swarm earthquakes, yellow: swarm earthquakes, red: post-swarm earthquakes. Left: locations from U.S. Navy catalog, Right: relative relocations. Boreholes are shown in purple and the well bore of well 34-9RD2 is indicated. The N, E and Down axes intersect at sea level.*

Figure 2.58 shows more detail of the evolution in time and space of the swarm. During the earliest, most intense part of the swarm, seismicity migrated northwards, eastwards and up, indicating the geometry and chronology of rupture. The dimensions of the rupture plane are 600 m vertically and 700 m horizontally, and the plane strikes N 20°E.
Moment tensors were successfully obtained for all earthquakes within 1 km of seismic station CE6 during the month of March 2005 as follows:

- 7 earthquakes prior to the main swarm,
- 14 earthquakes during the main swarm, and
- 17 earthquakes following the main swarm
Figure 2.59 shows a typical result for a co-swarm event. This mechanism is consistent with failure on the N 20°E-trending plane delineated by the relative relocations, and it furthermore has a net explosive mechanism.

Figure 2.59: Moment tensor results for an earthquake that occurred 3 March 2005, 03:07:33 UTC. Circle at bottom right shows seismic stations on an equal-area, upper-hemisphere plot.

Figure 2.60 shows 8 example earthquakes from the 14 swarm earthquakes processed. There is great uniformity of moment tensor type. The seismic zone delineated by the relative relocations (red line) does not correspond to either possible shear fault plane suggested by the results, but is instead consistent with the crack-opening component.
Figure 2.60: Summary diagram showing 8 example moment tensors for earthquakes from the swarm. The red line indicates the orientation of the seismic zone revealed by the earthquake relocations.

Figures 2.61 and 2.62 show similar example results for the set of 17 post-swarm earthquakes that was successfully processed. These earthquakes clearly have different mechanisms, and Figure 2.62 shows that these mechanisms are also very variable, in contrast with the great uniformity of the swarm earthquakes.

Figure 2.61: As for Figure 2.59 but for an earthquake of 29 March 2005, 12:09:43 UTC.
The results are summarized in Figures 2.63 and 2.64, which show source-type plots and the orientations of the “pressure” and “tension” axes respectively. Several deductions may be made:

- The pre-, co- and post-swarm earthquakes represent different modes of failure.
- All the pre- and co-swarm earthquakes had explosive mechanisms, whereas some of the post-swarm earthquakes had implosive mechanisms.
- Some of the pre- and post-swarm earthquakes had +CLVD components whereas none of the co-swarm earthquakes did.

The pre-swarm earthquakes form a uniform set with pressure axes sub-vertical and tension axes sub-horizontal. This contrasts with the co-swarm earthquakes which mostly had P-axes ranging from sub-vertical to SW orientated and sub-horizontal, and T-axes sub-horizontal and trending dominantly WNW. The orientation of principal axes for the post-swarm earthquakes resembled the pre-swarm earthquake set but there was much more variation (Figure 2.64).

These results may be interpreted as follows.

Prior to the injection experiment seismicity was consistent with a homogeneous stress field with a sub-vertical orientation of greatest compressional stress and a sub-horizontal, WNW-NW orientation of least compressive stress. Subsidiary failure occurred in response to local occurrences NE-orientated least compressive stress. Mode of failure varied from near volume-conserving to explosive.

Introduction of fluid into the formation modified the stress field, as is shown by the different type of seismic failure. The swarm earthquakes are consistent with a greater influence of sub-horizontal, SW-orientated greatest compressional stress. +CLVD components in earthquakes are not well understood but may be related to compensated closure of cavities. If so, their absence in
the swarm earthquake mechanisms would be consistent with the mode of failure being limited to cavity opening.

The suite of earthquakes that occurred after the swarm activity indicated more varied orientations of principal stress than before. This suggests a) that the injection experiment released much of the deviatoric stress locally such that the maximum and minimum principal stresses were more nearly equal than before, and b) that the injection-induced stress-field modification lasted at least until the end of March, i.e., for at least a month following injection.

2.3.6.5 Summary

Figure 2.65 summarizes the relative-relocation and the moment-tensor results. The combined results suggest that, as fluid entered the formation, a pre-existing fault (zone) was activated, extended, widened and opened. This fault (zone) had a strike of N 20°E, was 700 m long and 600 m high. It extended from near the bottom of well 34-9RD2 in a NE direction. Rupture progressed from the lower, SW end of the fault (zone) to the upper NE end. This orientation is inconsistent with any shear interpretation of the moment tensors, but is consistent with the crack-opening component in the mechanisms.

We tentatively suggest an “ear of corn” model for growth of the fault (zone) (Figure 2.65). The pre-existing fault (zone) is represented by the “kernel” (red), which progressively extends and widens as the earthquake swarm progresses. Shear faulting on “wing faults” accompanies activation of the main fault (zone) and accounts for the observed shear components in the moment tensors. This interpretation is not unique, and would benefit from future re-examination in collaboration with structural geologists familiar with the geology of the Coso geothermal field.
Figure 2.63: The results in “source-type” space. The “source-type” plot depicts the moment tensor in a form that is independent of source orientation. All simple shear-faulting mechanisms, whether strike-slip, normal or reverse, plot at the central point labeled DC (= double couple). The vertical coordinate \( k \) ranges from \(-1\) (\(-V\)) at the bottom to \(+1\) (\(+V\)) at the top of the plot, and indicates the magnitude and sign of the volume change involved. Mechanisms with explosive (volume increase) components lie above the horizontal line through the central point DC, and mechanisms with volume decreases lie below it. Pure, spherically symmetric explosions plot at point \(+V\) and pure implosions plot at \(-V\). The left-right coordinate \( T \) ranges from \(-1\) on the left (\(+\text{CLVD}\)) to \(+1\) on the right (\(-\text{CLVD}\)) side of the plot, and indicates the type of shear involved, with simple shears lying on the vertical line \( T=0 \) through the central point DC and more complex pure shears lying to the right or left of this line. In particular, opening (closing) tensile cracks, which involve both shear and volumetric deformation, lie at the point \(+\text{Crack}\) (\(-\text{Crack}\)). The points \( \pm\text{CLVD} \) and \( \pm\text{Dipole} \) represent mathematically idealized force systems whose possible physical significance is not clear, but probably related to the opening and closure of cracks in the presence of compensating fluid flow.

Figure 2.64: Pressure (\(P\)) and tension (\(T\)) axes for the pre-, co- and post-swarm earthquakes, plotted on upper-hemisphere stereographic projections. The \(P\) and \(T\) axes give a rough indication of the orientation of the greatest and least principal stresses respectively.
2.3.7 Software Development

Seismological studies at Coso under this project have required the development of a significant amount of computer software.

2.3.7.1 Earthquake source-mechanism determination
The full (moment-tensor) mechanisms of microearthquakes provide a rich source of information about active processes in geothermal reservoirs. Most existing methods for determining moment tensors, however, are restricted to earthquakes larger than about magnitude 4, and thus are of little use in geothermal contexts. Only the amplitude-ratio method (Julian, 1986; Julian and Foulger, 1996) presently can provide accurate moment tensors for microearthquakes. Existing software based on this method is inefficient to use, however, involving several poorly integrated computer programs and requiring excessive user interaction and file manipulation, so that analyzing large numbers of microearthquakes is impractical.

A major task under this project is the design and implementation of efficient moment-tensor software with a modern graphical user interface (GUI). This software will be used both in research into microearthquake processes at Coso and elsewhere and routinely in computing moment tensors as part of the U.S. Navy’s seismic monitoring of the Coso field. During 2005 we evaluated several options for computer languages and GUI libraries to use and have chosen the one best suited to the task and begun the design and programming of the new software.

The new software, MEQmec, is being written in the C++ language and uses Qt (Dalheimer, 2002), a C++ class library and toolkit for writing portable graphical user interfaces. Using Qt offers several benefits: Qt is an exceptionally high-quality product, featuring a wealth of well-designed components. Qt programs run on all important kinds of hardware, including Apple Macintoshes, IBM PCs, and SUN workstations, and operating systems, including UNIX, LINUX, Win32, and MacOSX. Because C++ compilers generate native machine code, Qt programs execute efficiently.

Two primary capabilities are needed in determining earthquake mechanisms: (1) Measuring polarities, amplitudes, and frequencies from digital seismograms, and (2) inverting these measurements to determine the moment tensor. In the initial development of MEQmec, we are concentrating on the second of these functions; adequate facilities already exist for making the initial measurements. Figure 2.66 illustrates a prototype of the interactive window of MEQmec on a Macintosh computer. On other systems, the appearance of the window follows local conventions.
2.3.7.2 Three-dimensional visualization

A mundane, but critical, need in a project such as this is for tools for visualizing three-dimensional objects such as points (such as earthquake hypocenters), curves (well-bores), scalar fields (temperature, seismic-wave speeds), and tensor fields (stress). We have identified two computer facilities for this purpose, ParaView and LiveGraphics3D, and have written programs to convert Coso data into formats used by these programs.

ParaView ([http://www-vis.lbl.gov/NERSC/Software/paraview/docs/HTML/paraview.htm](http://www-vis.lbl.gov/NERSC/Software/paraview/docs/HTML/paraview.htm) and [http://www.paraview.org/HTML/Index.html](http://www.paraview.org/HTML/Index.html)) is an open-source visualization application, developed with the support of the National Nuclear Security Administration's (NNSA) Advanced Simulation and Computing (ASC) program and the Sandia National Laboratories (SNL), Los Alamos National Laboratory (LANL), and Lawrence Livermore National Laboratory (LLNL). ParaView runs on Windows, Mac OS X, and UNIX operating systems, and makes powerful three-dimensional visualization available on all commonly used types of workstations. Because ParaView source code is freely available and not proprietary, its continued availability cannot be threatened by such factors as changes in corporate policy.
ParaView is a compiled program, so it executes efficiently, and it supports parallel processors, so it can be applied to extremely large data sets when necessary. Even with a single processor, our tests show that response is essentially instantaneous when displaying 100,000 earthquake hypocenters on a laptop computer. Figure 2.67 shows an example of a ParaView display.

Figure 2.67: ParaView display showing the distribution of seismic compressional-wave speeds at Coso as determined in the tomographic study described above in Section 2.3.4. The user can interactively rotate the view, change the color scale, and move the plane of the cross-sectional slice. The volume shown is 10 X 10 km horizontally and 11 km deep. View is to the southwest.
At the same time, *ParaView* has disadvantages: it is large and complex, and installing it on a computer can be a sizeable task. For communicating results rapidly to other workers on the EGS project, we have set up a secure password-protected web site, [http://cosomeq.wr.usgs.gov](http://cosomeq.wr.usgs.gov), that displays interactive rotatable three-dimensional microearthquake hypocenter images using the public-domain program *LiveGraphics3D* ([http://wwwvis.informatik.uni-stuttgart.de/~kraus/LiveGraphics3D](http://wwwvis.informatik.uni-stuttgart.de/~kraus/LiveGraphics3D)). This program is much less efficient than *ParaView*, but it is adequate for displaying small numbers (hundreds) of microearthquakes and, because it runs on any web browser, requires no special installation. Figure 2.57 shows an example of a *LiveGraphics3D* display.

### 2.3.7.3  Major programs written or significantly modified to date

**Earthquake Source-Mechanisms**
- **MEQmec** – Graphical user interface to program *focmec*

**Earthquake Hypocenter Location**
- **cat2dt** – Generate time-difference data from earthquake catalog
- **hypocc** – Simultaneously locate clusters of earthquakes
- **libttb3d** – Body-wave travel-time library for three-dimensional Earth models
- **libttplyr** – Body-wave travel-time library for plane-layered Earth models
- **qloc** – Locate earthquakes one at a time
- **toonpics** – Refine relative phase times by waveform cross-correlation

**Data Access and Display**
- **coso23d** – format Coso earthquake catalog for viewing with *LiveGraphics3D*
- **coso2xyz** – format Coso earthquake catalog for viewing with *IFRIT* (obsolete)
- **cosoextract** – Get seismic-wave reading data for specified Coso earthquakes
- **cosofetch** – Look up Coso earthquakes in any time interval
- **cosomap** – Plot earthquakes and other geophysical data on map of Coso area.
- **cosowells** – Look up traces of geothermal well boreholes
- **hdd2xyz** – format *hypocc/hypoDD* hypocenters for viewing with *IFRIT* (obsolete)
- **hdd2vtk** – format *hypocc/hypoDD* hypocenters for viewing with *ParaView*
- **qselect** – Select earthquakes satisfying user-defined criteria
- **simul2vtk** – Convert tomographic models for viewing with *ParaView*
- **wells2vtk** – Format well-bore traces for viewing with *ParaView*

**Seismic Tomography**
- **cosoqual** – Estimate quality of arrival-time data for Coso-format seismic events
- **simulspread** – Evaluate resolution of tomographic models

**Data Management**
- **qmatch** – Match earthquakes in two catalogs by origin times
- **segymmerge** – Extract continuous-time data from REFTEK data-logger files
These programs are available on request from B.R. Julian at the U.S. Geological Survey (julian@usgs.gov).
2.3.8 Publications and presentations


2.3.9 References


Dalheimer, M.K., 2002, Programming With Qt (Second ed.): Köln, Germany, O'Reilly, 499 p.


### 2.4 Magnetotellurics (Phil Wannamaker)

#### 2.4.1 Background and objectives

Electrical resistivity is a primary physical property of the Earth which can be strongly affected by geothermal processes. The geometry, bounds and controlling structures in existing production can be understood much more clearly if the electrical resistivity structure is accurately imaged.

At Coso, production data suggest abrupt northern and southern bounds to the entire system plus a possible partitioning of the east flank reservoir from the main west-central field. This can be verified through a detailed magnetotelluric (MT) survey with moderately dense coverage and a 3D analysis.

To this end, we have acquired through subcontract 58 MT soundings in an approximate grid distribution centered over the east flank area. In cooperation with this effort, the Geothermal Program Office (GPO) of the U.S. Dept. of the Navy funded 44 five-channel soundings plus a contiguous array line 6 km long for complete response sampling in the north-central Coso area which will be interpreted jointly with the EGS data. The total sounding map is shown in Figure 2.68.
Figure 2.68. Location map for Coso MT survey with diamond symbols denoting five-channel MT sites (geology including interpreted reservoir compartmentalization after Adams et al., 2000, and Whitmarsh, 2002) MT data sites funded by DOE/EGS are in blue, and by Navy/GPO in purple. Dense MT array line is in orange. Principal alteration areas of Devil’s Kitchen (DK), Coso Hot Springs (CHS), and Wheeler Prospect (WP) also shown.

2.4.2 Accomplishments

Most of the five-channel MT stations were taken in calendar 2003 by contractor Quan tec Geoscience using novel remote referencing techniques under direction of Co-I Wannamaker.
In short, serious non plane wave effects in Phase I of the survey were suppressed using the permanent MT observatory at Parkfield, CA. For Phase II, an ultra-distant remote reference was set up near Socorro, NM, some 1000 km to the east. Survey and reference time series were linked through fast ftp internet connection in cooperation with Coso Operating Company and the New Mexico Institute of Mining and Technology. This procedure and its successful results were reported in detail in Wannamaker et al. (2004, SGP Proc.). Remaining sites in the Navy portion plus the dense array survey were taken in the spring of 2004 using the Parkfield observatory as a reference. These results are of high quality also.

Figure 2.69. Location map for various remote references used in the Coso MT survey in order to effectively overcome interference from the BPA DC intertie (red line). Locations are Coso Hot Springs (CHS), Centennial Flat (CEN), Panamint Valley (PAN), Amargosa Valley (AMG), Parkfield (PKD), Salt Lake City, (SL), and Socorro (SO). Field acquisition modules and time series downloading in Socorro area shown at right. Coso Hot Springs and Reftek recording module shown at left.

Wannamaker edited and formatted the dense MT array line of 52 soundings deployed in an E-W orientation across the northern portion of the producing field for analysis. These data were inverted using a 2-D array algorithm developed by the P.I. under DOE support (Figure 2.70) (Newman et al., 2005, Proc. SGP). The cross section nicely traces the surficial overburden layer in the western portion of the line, abruptly deepening to the east as one crosses into Coso Wash valley. Below this overburden, there is a conspicuous, steeply west-dipping, moderately low resistivity zone roughly located below the northward projection of the east flank producing trend.
It is tempting to correlate this with a zone of higher permeability, fluid content and alteration compared to the host rocks. It may represent the bulk of the production reservoir beneath the east flank. The projection of wells 34-A9 and 34-9RD2 from about 400 m south of the profile is shown also. Recent redrill/extension of 34-9RD2 encountered large fractures at the bottom of the hole, which we take as further confirmation of the MT structure proximal to the well.

![Figure 2.70](image)

**Figure 2.70. Two-dimensional inversion section of TM mode of array MT data across the northern east flank of the Coso prospect. Wells 34-A9 and 34-9RD2 project northward to approximately site 021. Low resistivities are plotted with warm colors.**

In the third and fourth quarters of calendar 2004, the total of 102 tensor five-channel MT sites were QC’ed by the P.I. Wannamaker, and translated from the contractor coordinate system to the one traditionally used at the University of Utah. The combined data file including vertical magnetic field was delivered to G. A. Newman of Lawrence Berkeley National Laboratory for inversion with their massively parallel 3-D inversion code under separate support from the Navy/Geothermal Program Office. To construct a starting model for 3-D inversion, G. Newman and coworkers defined several profiles of 8-10 five-channel sites each and computed 2D inverse models using the code of Rodi and Mackie (2001, Geophysics) (Figure 2.71) (Newman et al., 2005, Proc. SGP). Several profiles in the central section of the field show the same west-dipping conductive feature identified previously by Wannamaker (Figure 2.70). These are completely independent data from the contiguous profile, so the verification of structure is reassuring. Newman et al. (2005, GRC Trans.) presented an initial 3-D inversion starting from the family of 2-D structures just described (Figure 2.72). The steep conductor along the west side of the east flank remains in the image.
Figure 2.71. Two-dimensional cross sections from subsets of the fine-channel stations inverted by G. Newman and coworkers using the code of Rodi and Mackie (2001, Geophysics). View is to the southwest, and low resistivities are plotted with cool colors. Approximate locations of extremal MT sites over each profile are also plotted. Dense array line of Figure 2.70 lies between the E24-E17 and the E09-E01 profiles. Vertical compression is a factor of two.
Figure 2.72. Depth slices of the iterated 3-D conductivity inversion of the Coso geothermal field (from Newman et al., 2005, GRC Trans.). MT site locations are shown and indicate the topography over the survey area. Well production intervals (solid line segments) are also shown and appear to correlate with a conductivity structural boundary in the image.

In March/05, Wannamaker received the full Fortran source code for the 3-D inversion program of Y. Sasaki (Sasaki, 2004, Earth Planets Space). This program is the basis for new inversion capability developments under a new EGS contract to Wannamaker, principally to greatly speed parameter Jacobian calculation and to save storage. An example calculation using the existing program appears in Figure 2.73, which considers a simple conductive prism in a quarter space host. Random static shift distortions, a common issue with MT data, have been added to the apparent resistivity responses with a standard deviation of 0.5 log units. Figure 2.73 shows that the original structure is recovered well in only seven iterations, within the smoothing constraints of the regularization. This includes reproduction of the static shifts and hence prevention of distortion of deeper structure images by such shifts. This run took 5 hours on a 3.4 GHz PC but used approximate derivatives for all iterations except the second. Use of rigorous Jacobians would expand the run time to several days, and is the principal bottleneck to productivity.

However, with the exception of Sasaki’s coworker T. Uchida, to our knowledge this source code has not been distributed to any others. Ph.D student Virginia Maris has been reorganizing and
generalizing this code using the Coso data set and we hope to have corresponding images of the Coso structure soon.

Figure 2.73. Horizontal and vertical sections for true model and corresponding inversion model for simple prism in a quarter space host (Sasaki, 2004, Earth Planets Space). Static shifts included in the synthetic data are shown in the lower right as circles and the recovered values are triangles. This run has been reproduced by Wannamaker with the donated Fortran source code.

Test Prism Inversion (Sasaki, 2004)  
(y=1000m, z=700m, z=150m)

2.5 Hydraulic Stimulation and Testing of Injection Well 34A-9 (Peter Rose, Jess McCulloch, and Mike Mella)

2.5.1 Background and Objectives
A hydraulic stimulation experiment was conducted under very low wellhead pressures on the very tight injection well 34A-9 during 1993-1994 in an attempt to increase near-reservoir permeability. During these experiments, steam condensate was injected in large volumes at pressures well below the least principle stress. The experiment was very successful as the otherwise failed well was turned into a highly permeable injector.

2.5.2 Stimulation of 34A-9 under Low Wellhead Pressures

Coso well 34A-9 was drilled to a depth of approximately 2,740 m (9,000 ft) in 1993 with the trajectory shown in Figure 2.74. The well was drilled into one of the hottest portions of the field with measured temperature exceeding 300°C. However, the well had such low productivity that it could not be made to flow. The well possessed some zones of lost circulation and it was decided to attempt a hydraulic stimulation at low wellhead pressures to determine if the injectivity of the well might be increased to the extent that it could serve as an injection well.

The pre-stimulation injectivity of Coso well 34A-9 was not well documented, and no downhole pressure data were recorded during the stimulation. Initially, the well would accept about 2.5 l/s (40 gpm) of steam condensate at a WHP of 0.62 MPa (90 psi).

High pressure pumps were unavailable for the stimulation experiment, and as a result, low-pressure pumps were used and wellhead pressures never exceeded about 0.7 MPa. After less than 240 m³ (1500 bbl) of injection of steam condensate at a rate of 2.5 l/s, the wellhead pressure had dropped to 0 MPa. The injection rate was increased to 28 l/s (450 gpm) and maintained at that rate for one day, while the wellhead pressure remained at 0 psi. Finally, the injection flow rate was raised to 50 l/s (800 gpm) for eight days, with the wellhead pressure at 0 psi. The total volume injected for the entire stimulation was only 12,700 m³ (80,000 bbl). Significant microseismicity was recorded during the stimulation experiment by the Navy Geothermal Program Office’s microseismic sensor array.

2.5.3 Circulation Testing of 34A-9

Figure 2.74. Plan view of the northeast section of the Coso geothermal field, showing the trajectory of the target stimulation well 34A-9.
34A-9 was put on line in 1994 and used as an injection well for several years until damage to the shallow casing rendered it inoperable. In 2004, a tie-back repair of the casing resulted in the well being put back on line as an injector (Rose et al, 2005). At the end the workover in 2004, a second hydraulic stimulation was conducted, again at low wellhead pressures. At the end of the stimulation, 34A-9 would accept 126 l/s of hot, separated brine with a wellhead pressure of 0.41 MPa (60 psi). Significantly microseismicity was measured within the reservoir volume in and around the injection zone for several weeks after 34A-9 was put on injection.

In order to determine the fate of fluids injected into the newly stimulated 34A-9, a tracer test was initiated on 1 September, 2004. In this test, 100 kg of the tracer 1,3,6-naphthalene trisulfonate was injected as a pulse. The neighboring liquid-producing east flank wells were subsequently sampled and analyzed for the tracer. Figure 2.75 shows a plot of 1,3,6-naphthalene trisulfonate returns to the sampled wells. The return curve confirms that the stimulation of 34A-9 resulted in a very strong hydraulic connection to the neighboring well 38-9, with a slower but significant and building return to 38A-9.

![Figure 2.75. Tracer returns from tagged injection well 34A-9 to several Coso east-flank production wells.](image)

The tracer data were analyzed using a systematic approach developed at Idaho National Laboratory (Shook and Forsman, 2005). Using this approach, the tracer data are first converted to an “age distribution function”, E(t):

\[
E(t) = \frac{C(t) \cdot q_{inj}}{M_{inj}}
\]

where \(C(t)\) is the measured tracer concentration in mass per volume, \(q_{inj}\) is the injection-fluid flow rate, and \(M_{inj}\) is the mass of tracer injected. The units of E(t) are inverse time. Shown in Figure 2.76 is a plot of E(t) for the 1,3,6-naphthalene trisulfonate tracer measured in samples taken from 38-9 during the circulation test. A strong but delayed return of the tracer was likewise observed within well 38A-9, but for the purposes of this analysis only the returns to 38-9 are considered. No tracer was reinjected into 34A-9 and, therefore, no deconvolution was required.
Figure 2.76. The age distribution function $E(t)$ plotted for the 1,3,6-naphthalene trisulfonate tracer data from the 2004 circulation test at the Coso reservoir, after 48 days into the test.

The program extrapolates the deconvoluted curve to infinite time assuming an exponential decay of the long-tailing portion of the return curve (Shook, 2005). The mean-residence time and the area under the extrapolated curve are then used to calculate the tracer-swept pore volume $V_p$ according to the expression:

$$V_p = \frac{m}{M} \cdot Q \cdot t^*$$

where $m$ is the mass of tracer recovered, $M$ is the mass of tracer injected, $Q$ is the average rate of fluid injected into the injection well and $t^*$ is the mean-residence time. Details on the computational approach have been reported elsewhere (Shook and Forsman, 2005). The fraction of tracer returned to 38-9 and the tracer-swept pore volume, as calculated by the INL software were 35% and 41,000 m$^3$, respectively.

2.5.4 References


2.6 Redrilling and Testing of Stimulation-Target-Well 34-9RD2 (Peter Rose, Jess McCulloch, and Mike Mella)

2.6.1 Background and Objectives
The major focus during FY2005 was the stimulation of 34-9RD2, with the intent of developing an EGS doublet between this injector and the recently drilled 38C-9 directly to the south (see Figure 2.77). 34-9RD2 was originally drilled in 2000 and possessed moderate shallow permeability and very low deep permeability. The well could not then be made to flow and was subsequently used as an injection well. Spent brine and steam condensate were alternately injected into the well until a break in the shallow casing required that the well be shut in.

A successful stimulation of 34-9RD2 would not only confirm the Coso/EGS concept that hydraulic conductivity can be created within fractures that are critically stressed and optimally oriented for shear failure, but would also add 5 MWe of production at the Navy II power plant.

![Figure 2.77. Plan view of the east flank of the Coso geothermal field showing wellhead locations and trajectories of injection wells (in blue) and production wells (in red). Arrows around certain wells indicate the orientation of the maximum horizontal stress. The orientation indicated for 34-9RD2 is provisory.](image)

### 2.6.2 Design of the Pre-Stimulation Hydraulic Testing Program

A hydraulic test program is to be conducted prior to the massive stimulation. This program has the objective to determine various hydraulic parameters required for the final design and for the later evaluation of the subsequent stimulation.

The program is designed in such a way that it provides the following information:

- Initial formation pressure
- Pre-stimulation properties of the near- and the far-field
• Flow conditions (turbulent/laminar)
• Interference with neighboring wells
• Pressure required to induce seismic activity
• Distribution of permeable fractures

In order to have a maximum chance for obtaining the desired data, a 4-element program is proposed consisting of (i) a pre-test survey, (ii) a slug test, (iii) a step-rate injection and (iv) a constant rate injection.

According to previous measurements in 34-9R2, it is expected that the static fluid level is about 2,200 ft below surface (pers. comm. P. Spielman). If this will be confirmed by the pre-test survey, the complete test program will be conducted at a free moving fluid level, i.e. at zero-wellhead pressure. This would imply

1. the need for continuous downhole monitoring and
2. longer test durations due to the prolongation of wellbore storage effects.

The proposed test program is shown in Table 8 and conceptually in Figure 2.78.
### Table 8: The parameters of the preliminary test design. Items with low priority (no or one symbol) could be skipped for cost or other reasons.

<table>
<thead>
<tr>
<th>Stage</th>
<th>Test phase</th>
<th>Duration</th>
<th>Q [bpm]</th>
<th>V$_{inj}$ [bbl]</th>
<th>Priority</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>pre-test survey</td>
<td>&gt;12 h</td>
<td>0</td>
<td>0</td>
<td>□□□</td>
</tr>
<tr>
<td>2</td>
<td>slug/pulse test</td>
<td>&lt; 1 min</td>
<td>&gt;10</td>
<td>~10</td>
<td>□□□</td>
</tr>
<tr>
<td>3</td>
<td>fall-off</td>
<td>&gt; 1 h</td>
<td>0</td>
<td>0</td>
<td>□□□</td>
</tr>
<tr>
<td>4</td>
<td>first step</td>
<td>6 h</td>
<td>0.38</td>
<td>137</td>
<td>□□□</td>
</tr>
<tr>
<td>5</td>
<td>pTS-log</td>
<td></td>
<td></td>
<td></td>
<td>□□□</td>
</tr>
<tr>
<td>6</td>
<td>intermediate step</td>
<td>2 h</td>
<td>0.75</td>
<td>90</td>
<td>□□□</td>
</tr>
<tr>
<td>7</td>
<td>pTS-log</td>
<td></td>
<td></td>
<td></td>
<td>□□□</td>
</tr>
<tr>
<td>8</td>
<td>intermediate step</td>
<td>2 h</td>
<td>1.50</td>
<td>180</td>
<td>□□□</td>
</tr>
<tr>
<td>9</td>
<td>pTS-log</td>
<td></td>
<td></td>
<td></td>
<td>□□□</td>
</tr>
<tr>
<td>10</td>
<td>final step</td>
<td>2 h</td>
<td>3.00</td>
<td>360</td>
<td>□□□</td>
</tr>
<tr>
<td>11</td>
<td>pTS-log</td>
<td></td>
<td></td>
<td></td>
<td>□□□</td>
</tr>
<tr>
<td>12</td>
<td>fall-off</td>
<td>48 h</td>
<td>0</td>
<td>0</td>
<td>□□□</td>
</tr>
<tr>
<td>13</td>
<td>constant rate</td>
<td>24 h</td>
<td>0.63</td>
<td>906</td>
<td>□□□</td>
</tr>
<tr>
<td>14</td>
<td>pTS-log</td>
<td></td>
<td></td>
<td></td>
<td>□□□</td>
</tr>
<tr>
<td>15</td>
<td>fall-off</td>
<td>&gt; 48 h</td>
<td>0</td>
<td>0</td>
<td>□□□</td>
</tr>
</tbody>
</table>
Figure 2.78: Conceptual simulation of the pre-stimulation test program as given in the preceding table.

For the given test program a pressure response has been simulated with roughly estimated formation parameters. Currently, this is only meant to be a sketch for illustration but more realistic predictions can be computed once the openhole parameters are better constrained.

2.6.3 Preliminary Design of the Hydraulic Stimulation of 34-9RD2

Many of the important input parameters required for a detailed design of the stimulation will not be available before March 2005, when the deepening and initial testing of the well will be finished. Therefore, we focused on clarifying general considerations and strategic concepts providing guidelines for the preparations of the logistics and equipment required for the
conduction of the program. The actual performance of the experiments will strongly depend on
the reaction of the reservoir and will be modified and adapted in the field. Therefore, the near
real-time monitoring and interpretation of the microseismic activity and the hydraulic data will
play a crucial role for the decision making and the attainment of an optimum control and
efficiency of the operation. Currently, the stimulation design includes various strategic elements
that have been developed and tested in various projects during the last years. Table 9 shows the
preliminary plan. Injection pressures have been calculated based on the results of Sheridan and
Table 9: The preliminary design of the hydraulic stimulation.

<table>
<thead>
<tr>
<th>stage</th>
<th>description</th>
<th>$P_{max}$ (psi)</th>
<th>$V_{scoop}$ (bbl)</th>
<th>$V_{top}$ (bbl)</th>
<th>comment</th>
<th>review points</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>pressure well</td>
<td>$&lt; 0$</td>
<td>?</td>
<td>?</td>
<td>carefully monitor onset of seismicity; monitor $P_{tud}$ if possible</td>
<td>cross-check predicted pressures and seismic velocity model</td>
</tr>
<tr>
<td>2</td>
<td>shear-fracture initiation cycle 1</td>
<td>750</td>
<td>300</td>
<td>300</td>
<td>induce fracture shearing at lower bound of target pressure; attain pressure within minimum time</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>venting</td>
<td></td>
<td></td>
<td></td>
<td>clean fracs &amp; deflate system</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>pTS-log</td>
<td>200</td>
<td>?</td>
<td>?</td>
<td>check flow profile; stages 2-4 can be omitted if necessary</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>shear-fracture initiation cycle 2</td>
<td>1500</td>
<td>2000</td>
<td>2500</td>
<td>induce fracture shearing at upper bound of target pressure; attain pressure within minimum time</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>venting</td>
<td></td>
<td></td>
<td></td>
<td>clean fracs &amp; deflate system</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>pTS-log</td>
<td>200</td>
<td>?</td>
<td>?</td>
<td>check flow profile</td>
<td>if results OK then goto 9</td>
</tr>
<tr>
<td>8</td>
<td>additives, other measures</td>
<td>1500</td>
<td>1000</td>
<td>3300</td>
<td>try to improve near-well conditions by injecting heavy brine, gel, plugs</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>fracture propagation phase 1</td>
<td>1500</td>
<td>30000</td>
<td>33000</td>
<td>propagate initiated fractures; monitor propagation with seismic network</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>pTS-log</td>
<td>1500</td>
<td>?</td>
<td>?</td>
<td>check flow profile</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Shut-In</td>
<td></td>
<td></td>
<td></td>
<td>monitor pressure fall-off with pTS-tool, perform in-situ well test analysis</td>
<td>if results OK then goto 20</td>
</tr>
<tr>
<td>12</td>
<td>hydro-frac step 1</td>
<td>2000</td>
<td>500</td>
<td>3300</td>
<td>increase $p$ to induce shear failure on more fracs and/or open hydro-frac</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>hydro-frac step 2</td>
<td>2500</td>
<td>500</td>
<td>3400</td>
<td>increase $p$ to induce shear failure on more fracs and/or open hydro-frac</td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>hydro-frac step 3</td>
<td>3000</td>
<td>500</td>
<td>3450</td>
<td>increase $p$ to induce shear failure on more fracs and/or open hydro-frac</td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>deblinding</td>
<td>500</td>
<td></td>
<td></td>
<td>deblind frac prior to re-frac cycle if shut-in or venting</td>
<td></td>
</tr>
<tr>
<td>16</td>
<td>re-frac cycle</td>
<td>3000</td>
<td>500</td>
<td>3500</td>
<td>try to achieve maximum $p$ within minimum time</td>
<td></td>
</tr>
<tr>
<td>17</td>
<td>pTS-log</td>
<td>2000</td>
<td>?</td>
<td>?</td>
<td>check flow profile above and below frac opening pressure</td>
<td>if results OK goto 20</td>
</tr>
<tr>
<td>18</td>
<td>additives, other measures</td>
<td>2000</td>
<td>1000</td>
<td>3850</td>
<td>try to improve near-well conditions by injecting heavy brine, gel, plugs...</td>
<td></td>
</tr>
<tr>
<td>19</td>
<td>pTS-log</td>
<td>300</td>
<td>?</td>
<td>?</td>
<td>check flow profile above and below frac opening pressure; can be omitted if necessary</td>
<td></td>
</tr>
<tr>
<td>20</td>
<td>fracture propagation phase 2</td>
<td>1500</td>
<td>50000</td>
<td>38500</td>
<td>continue to propagate fractures in shear mode, establish connectivity towards producer; carefully monitor propagation with seismic network</td>
<td>if no seismicity towards producer, then shut-in producer</td>
</tr>
<tr>
<td>21</td>
<td>pTS-log</td>
<td>1500</td>
<td></td>
<td></td>
<td>check final flow profile</td>
<td></td>
</tr>
<tr>
<td>22</td>
<td>Shut-In</td>
<td></td>
<td></td>
<td></td>
<td>monitor pressure fall-off with pTS-tool</td>
<td></td>
</tr>
</tbody>
</table>

fracture initiation phase 1 (FP1) >> near-wellbore impedance
fracture initiation phase 2 (FP2) >> near-wellbore impedance
fracture propagation phase (FP3) >> reservoir connectivity
2.6.4 Workover of 34-9RD2

In order that 34-9RD2 might endure the rigors of a massive-stimulation experiment, it was necessary to replace a slotted liner running between 3600 ft and 7600 ft by cementing a 7-in liner from the surface to the well’s total depth. The old liner was easily removed, revealing a wellbore with extensive washout regions and large permeable fractures, due to the injection of large volumes of steam condensate and undersaturated (in calcite) brine. Before it would be possible to cement the new casing, however, it would be necessary to cement the open fractures and washout regions. The fractures and washout zones were successfully patched, but upon redrilling the cement, the bit side-tracked in a large washout zone at approximately 4600 ft. Attempts to find the hole failed and 34-9RD2 was subsequently redrilled between a depth of 4600 ft and 7900 ft and a 7-in liner was successfully reverse-cemented from surface.

With the casing shoe set at 7900 ft, the plan was to drill 500 ft or more of ‘open-hole’ that would be subjected to a massive hydraulic stimulation. At a depth of 8625 ft, no lost-circulation zones had been intersected in the 725-ft open-hole segment, which was considered to be extremely tight. A suite of logs including sonic velocity, natural gamma, and density were conducted followed by the deployment of the ALT borehole televiewer. Due to complications resulting from drill mud in the open-hole segment, causing the televiewer to stick-slip, the borehole televiewer logging exercise was rescheduled for the next day when the mud would be displaced with water.

In the interim, drilling resumed and the well was deepened by 150 ft. It was during this deepening that three major lost-circulation zones were intersected, with total mud losses in a very large lost-circulation zone at a depth of 8685 ft. In the few hours required to drill from 8625 to 8685 ft, a well that had been an excellent stimulation target was transformed into an excellent injector—obviating the need for stimulation. Drilling continued with no returns to a total depth of 8775 ft, while injecting water at rates as high as 7.5 bpm. Microseismic data collected during this latter drilling phase indicated earthquake activity to the south of the 34-9 wellpad, suggesting that the injection fluids flowed in this southerly direction.

Four years of study, data analysis, geophysical surveys, well workovers, the drilling of producer 38C-9, the low-pressure stimulation of 34A-9, and the redrilling and completion of 34-9RD2 preceded the anticipated stimulation of this candidate EGS injector. Unfortunately for the EGS program, large conductive fractures were encountered during the redrilling of 34-9RD2, which meant that the well no longer qualified as a candidate stimulation target.

However, an alternative EGS-type stimulation project is currently scheduled for late in FY06 in another region on the periphery of the Coso field. It will serve as an excellent opportunity to test the very stimulation concepts that were planned for 34-9RD2. An injection well designated 46A-19RD was drilled in the southwest and hottest portion of the Coso field to a depth of approximately 12,700 ft. Injection into the well has been limited because permeability in the bottom of the well, where injection is needed, is very low. New casing will be cemented to a depth of approximately 10,000 ft, leaving the existing slotted liner in place below 10,000 ft. The Navy’s temporary seismic array will be deployed around 46A-19 and a stimulation experiment will then be performed by injecting at pressures below the minimum horizontal stress while
monitoring the development of the microseismic cloud. Finally, a circulation test, complete with tracer testing, will be conducted to determine the success of the stimulation experiment.

2.6.5 Circulation testing of 34-9RD2

Two tracer tests were conducted in conjunction with circulation tests at the Coso EGS test well 34-9RD2. The first of these tests was a liquid phase tracer test to determine the connectivity of the test well to the surrounding producing wells. For this test 100 kg of 1,3,5-NTS was injected into well 34-9RD2 on 12 May 2005. Over the course of the following days and months brine samples were taken from the surrounding wells. The test wells and the surrounding production wells with the well trajectories are shown as Figure 2.79.

\[\text{Figure 2.79. East Flank injectors and producers}\]

The second tracer test was a vapor-phase test using n-propyl alcohol as the tracer. 500 kg of n-propyl alcohol was injected into 34-9RD2 on 7 July 2005. Brine and condensed steam samples were taken from the surrounding production wells in the subsequent days and months. The objective of this test was to determine the connectivity of the EGS test well with the production wells by vapor pathways.

Figure 2.80 shows the northeast section of the East Flank including the injector 34-9RD2 and the 38-9 well pad.
The samples taken from the liquid phase tracer test were analyzed using reversed-phase HPLC with fluorescence detection. Figure 2.81 shows the return of the tracer 1,3,5-NTS.

**Figure 2.81. Tracer return curve for 1,3,5-NTS**
34-9RD2 showed a strong liquid connectivity to production well 38C-9. Further analysis of the tracer test also showed that approximately 75% of the tracer was recovered in 38C-9.

To facilitate the use of alcohols as tracers in larger reservoirs the limit of detection for the alcohol tracers needed to be reduced. An inexpensive, reliable, analytical method needed to be developed that would allow for a lower limit of detection. Several different methods were examined before SPME combined with analysis by gas chromatography (GC) and flame ionization detection (FID) was decided upon. The benefits of SPME-GC-FID for detecting the alcohols included cost, ease of use, and repeatability. N-propanol was detected from some of the wells and plotted in figure 2.82. The concentrations were corrected for thermal decay assuming an average temperature of 300°C using the decay kinetics developed by Adams (Adams, 2000).

![34-9RD2 Propanol](image)

Figure 2.82. Return curve of n-propanol from 34-9RD2 injector.

Returns of the liquid-phase and vapor-phase tracers were plotted together as E(t) in reciprocal days vs. days after injection, where E(t) is the concentration of tracer multiplied by the flow rate of the injector divided by the mass of the tracer injected (see Figure 2.83). Converting both tracer returns into E(t) data is done in order to normalize the results.
From a comparison of the two tracer tests a few interesting things appear. The first arrival time to well 38C-9 for n-propanol was slightly shorter than that for 1,3,5-NTS. Also, 1,3,5-NTS was not found in well 38D-9 but n-propanol was, suggesting a steam-only pathway from injector 34-9RD2 to 38D-9. Propanol was not found in 38B-9 but was found in 38D-9. This occurrence may be explained by a steam pathway that feeds the 38D-9 well but bypasses the 38B-9 well. Further work and testing may have to be done in order to understand exactly where vapor pathways exist and how they behave in this reservoir.

2.6.6 References

ACGIH. (1995), *Threshold Limit Values (TLVs) for Chemical Substances and Physical Agents and Biological Exposure Indices (BEIs)*. American Conference of Governmental Industrial Hygienists p. 32


Supelco (2003), *Chromatography Products for analysis and Purification*. Supelco p. 348-358

3.0 Modeling EGS Processes

3.1 Mechanical, Mineralogical, and Petrophysical Analysis of Fracture Permeability (Steve Hickman and Nick Davatzes)

3.1.1 Stress model for the East Flank and surrounding regions

In this section, a stress model for the East Flank is derived by combining observations from the hydraulic fracturing experiments, wireline log analysis, and image log analysis. (1) The hydraulic fracturing tests are used to estimate the gradient in the minimum horizontal stress, $S_{h_{\text{min}}}$, from measurements at two depth intervals (discussion in Section 2.1.4). (2) Bounds on the maximum horizontal stress, $S_{H_{\text{max}}}$, are calculated by combining estimates of rock strength (derived from the correlation of experimental measurements of rock strength to wireline velocity logs) with an analysis of borehole wall breakouts in borehole image logs (Section 3.1.1.1 below). (3) The vertical stress, $S_V$, is estimated from wireline density logs. Finally, we used this integrated stress model to evaluate the potential for slip on well-oriented strike slip and normal faults in the East Flank reservoir.

3.1.1.1 Bounds on greatest horizontal principal stress

Borehole breakouts occur where the stress concentration at the borehole wall exceeds the unconfined compressive strength ($C_0$) of the rock (Moos and Zoback, 1990) (Figure 3.1). Thus, the presence or absence of breakouts and their widths constrain the stress state along the well if $C_0$ is known. Given that only a single breakout was observed in well 38C-9 (Sheridan and Hickman, 2004) and none were observed in well 34-9RD2 (Davatzes and Hickman, 2006), we used the general absence of breakouts in both wells to determine upper bounds to the magnitude of $S_{H_{\text{max}}}$. This analysis used $S_{h_{\text{min}}}$ magnitudes measured in both wells (Figure 3.2) together with theoretical models for breakout formation in inclined wells based upon the elastic concentration of stresses around a circular borehole summarized for a vertical borehole in Figure 3.1 (Moos and Zoback, 1990; Peska and Zoback, 1995).

This represents a new analysis for well 34-9RD2 and an update to previous bounds on $S_{H_{\text{max}}}$ from well 38C-9 (Sheridan and Hickman, 2004) using recent laboratory measurements of rock mechanics parameters carried out under the EGS project (TerraTek, 2004; Appendix D). These measurements were conducted on dry hornblende-biotite-quartz diorite (HBQ diorite) from Coso well 64-16 at approximately 2820 ft MD. The use of these data in our analysis is justified since
HBQ diorite best represents rocks encountered in wells 38C-9 and 34-9RD2 (Kovac and Moore, 2005).

**Figure 3.1:** Illustration of stress acting on a vertical borehole wall when overburden ($S_V$) is a principal stress. When the circumferential hoop stress ($\sigma_{\theta\theta}$ in the plot of azimuth versus effective stress) exceeds the compressive strength of the rock ($C_0$), breakouts form in the direction of $S_{hmin}$ as shown in the sketch of a borehole on the right. If the hoop stress becomes tensile and exceeds the tensile strength of the rock, tensile fractures will form in the direction of $S_{Hmax}$. Breakout width is determined by the azimuthal distance over which the stress concentration exceeds $C_0$, which is promoted by high differential stresses and low mud weight relative to formation fluid pressure ($\Delta P$). Therefore, if $C_0$, $\Delta P$, and $S_{hmin}$ are known, the magnitude of $S_{Hmax}$ can be estimated.

To estimate $C_0$ we used uniaxial and triaxial measurements of compressive strength on HBQ diorite (Figure 3.2a) to obtain a reference value for $C_0$. This value, together with laboratory measurements of $V_P$ on the same samples at high confining pressures (TerraTek, 2004; Appendix D), was then compared to measurements of $C_0$ as a function of $V_P$ from core samples of Lac du Bonnet granite at depths up to 1 km (Annor and Jackson, 1987; Figure 3.2b). (Annor and Jackson currently provide the most complete and readily available measurements of $C_0$ and $V_P$ in granitoid rocks acquired by a single high quality method.) We then required that a least squares fit of a straight line to the Annor and Jackson data pass through $C_0$ determined for the HBQ diorite to arrive at the following empirical strength law for the East Flank:

$$C_0 = 13899.29 + 2358.3(V_P)$$  \hspace{1cm} (1)

where $C_0$ is in psi and $V_P$ is in km/sec. We then applied Equation 1 to in-situ measurements of $V_P$ from wireline logs to estimate $C_0$ as a function of depth in well 34-9RD2 (Figure 3.2c). Gaussian smoothing of the $V_P$ data best represents bulk properties of the host rock while giving some estimate of the uncertainty in the measurements and is therefore used to constrain $C_0$ in the stress model. Estimated values of $C_0$ range from 18,720 to 30,360 psi in the raw data and 22,490 to 27,910 psi in the smoothed data, probably reflecting variations in rock type and damage as
well as hydrothermal alteration along the borehole (Figure 3.2c) as documented by Kovac et al. (2005). Additional uncertainty in this empirical correlation is indicated by the error bars in Figure 3.2c. As no $V_p$ logs are available for well 38C-9, we used the average strength from the upper part of 34-9RD2 (Figure 3.2c) to estimate $S_{Hmax}$ for that well. The values of $C_0$ used to constrain $S_{Hmax}$ in wells 34-9RD2 and 38C-9 were 27,000 psi and 25,500 psi, respectively. These values will be further refined when we carry out rock mechanics tests on core recently recovered from well 34-9RD2.
Figure 3.2: (a) Mohr diagram showing compressive strengths determined on 6 samples of dry hornblende-biotite-quartz diorite (HBQ diorite) from Coso well 64-16 at approximately 2820 ft MD (TerraTek, 2004; Appendix D). The red circle represents an unconfined compressive strength ($C_0$) test, whereas the other circles represent triaxial compressive strength tests at a variety of confining pressures. The Mohr-Coulomb failure criterion for this rock (red line tangent to these circles) is very well-constrained, with cohesion of 7035 psi and internal friction angle of 38.2°. Although most tests were conducted at room temperature, one test at 200° C indicates that short-term compressive strength for these rocks is relatively insensitive to temperature. (b) Unconfined compressive strength ($C_0$) as a function of P-wave velocity ($V_P$) from tests on Lac du Bonnet granite (Annor and Jackson, 1987) and the Coso HBQ diorite. Linear least squares best fit to the Annor and Jackson data (black dashed line) was forced to coincide with the strength and $V_P$ measurements made on the Coso HBQ diorite (red dashed line, Equation 1 in the text). The overall error due to scatter of the Annor and Jackson data is represented by the grayed region. (c) Raw and smoothed $V_P$ log of well 34-9RD2 and estimated variation of $C_0$ with depth using Equation 1.

In addition to $C_0$ and the magnitude of $S_{hmin}$, several other parameters must be estimated or measured to constrain $S_{hmax}$. Borehole deviation angle and azimuth were determined from directional surveys and the local azimuths of $S_{hmin}$ were determined directly from observations of wellbore failure (Figure 3; Sheridan and Hickman, 2004). Current (i.e., post-production) fluid pressures – as opposed to pre-production values used in our geologic failure analysis (c.f., Figure 3.3) – are needed to calculate the concentration of effective stresses around the borehole and were estimated from temperature/pressure surveys conducted in both wells during static (shut in) conditions. Minimum drilling mud pressures experienced by logged intervals of each well prior to image logging were determined from daily drilling reports. Finally, the internal friction angle (38.2°) was determined from the slope of the failure envelope in Figure 3.2a.

We calculated the vertical stress ($S_V$) using a geophysical density log run in well 34-9RD2 at depths of 3609-6497 ft MD and making the reasonable assumption (based upon the uniform lithology penetrated by this well) that the average density from this log (2.65 gm/cm$^3$) applied throughout the entire well. In accordance with the Coulomb failure criterion, frictional failure (i.e., normal faulting) would then occur at a critical magnitude of $S_{hmin}$ given by (Jaeger and Cook, 1979):

$$S_{hmin\ crit} = (S_V - P_p) / [(\mu^2 + 1)^{1/2} + \mu]^2 + P_p$$

(2)

where $\mu$ is the coefficient of friction of preexisting faults. It is assumed here that $\mu$ ranges from 0.6 to 1.0, in accord with laboratory sliding experiments on a variety of rock types (Byerlee, 1978). Estimates of undisturbed (i.e., preproduction) formation fluid pressure were obtained assuming that $P_p$ was in hydrostatic equilibrium with a water table at the surface (Paul Spielman, pers. comm., 2003; Joe Moore, pers. comm. 2004) and by integrating water density as a function of pressure and temperature as appropriate to ambient geothermal conditions, and including a small correction for total dissolved solids. In this manner, we calculated the range of $S_{hmin}$ magnitudes at which normal faulting would be expected along optimally oriented faults (Figure 3.3).
Figure 3.3: Stress magnitudes for the East Flank derived from measurements in wells 38C-9 (Sheridan and Hickman, 2004) and 34-9RD2 (locations in Section 2.1.2, Figure 2.1). The least horizontal principal stress ($S_{hmin}$) was measured using hydraulic fracturing tests at 3703 ft total vertical depth (TVD) in well 38C-9 (Sheridan and Hickman, 2004) (Section 2.1.4.1 Figure 2.13) and at 7817 ft TVD in well 34-9RD2 (Section 2.1.4.2 Figure 2.15). The depth extent of image logs acquired in the two wells is shown by vertical lines, with the EMI log obtained in 38C-9 and the FMS log obtained in 34-9RD2. The symbol “BO” denotes the sole breakout observed in these two wells, which was seen at a depth of 6419 ft in well 38C-9. Upper bounds (with error bars) to the greatest horizontal principal stress ($S_{Hmax}$) were obtained based on the general absence of breakouts using the estimates of $C_0$ shown in Figure 3.2c. Dashed orange lines indicate the range of $S_{hmin}$ magnitudes at which normal faulting would be expected given the calculated vertical stress ($S_v$) for coefficients of friction of 0.6–1 (see text). Red dashed lines indicate the range of $S_{Hmax}$ where strike-slip faulting would be expected assuming that $S_{hmin}$ increases linearly with depth and passes through the values of $S_{hmin}$ measured in these two wells. Pore pressure ($P_p$) and failure envelopes were drawn assuming that the pre-production water table was in hydrostatic equilibrium with the surface under present-day thermal conditions.
3.1.1.2 Stress and strain in the different regions of the geothermal field and outside the geothermal field

An initial comparison of $S_{\text{hmin}}$ values from hydraulic fracturing tests in wells 38C-9 (Sheridan and Hickman, 2004) and 34-9RD2 (Davatzes and Hickman, 2006) with the normal faulting failure envelope (Figure 3.3) indicates that $S_{\text{hmin}}$ in the East Flank at depths of 3,000 to 9,000 ft MD is very close to that required for incipient normal faulting on optimally oriented faults. That such optimally oriented faults do, indeed, exist in the East Flank is indicated by surface mapping of faults at high angle to $S_{\text{hmin}}$ that offset Holocene sediments (e.g., Section 2.1.2 Figure 2.1) and by analysis of borehole image logs from 38C-9 and a number of nearby wells (Sheridan and Hickman, 2004). This conclusion is also consistent with the abundant petal-centerline fractures seen in the East Flank and Coso Wash faults, which are favored in normal faulting environments because of the low mean stress (Li and Schmitt, 1997, 1998).

However, an immediate assumption that normal faulting dominates is tempered by the potential influence of $S_{\text{Hmax}}$. Analysis of stress magnitudes indicates that $S_{\text{Hmax}}$ in the East Flank at depths of 3,000 to 9,000 ft MD could be significantly in excess of $S_V$ (Figure 3.3). By applying the same type of frictional failure analysis as was applied for normal faulting (i.e., Equation 2) to strike-slip failure, we see that upper bounds to $S_{\text{Hmax}}$ are equal to or greater than the critical values required for frictional failure on optimally oriented strike-slip faults under pre-production fluid pressure conditions (Figure 3.3). If the actual values of $S_{\text{Hmax}}$ are close to these upper bounds, then the East Flank of the CGF is in a transitional stress regime between normal and strike-slip faulting. Nonetheless, in the absence of prevalent breakouts with measurable width our analysis of $S_{\text{Hmax}}$ only provides upper bounds—so $S_{\text{Hmax}}$ could be much smaller. Thus, the propensity for strike-slip faulting in the East Flank, common in the regions surrounding the geothermal field (Monastero et al., 2005), is uncertain, whereas the proximity of the measured $S_{\text{hmin}}$ to failure (requiring only a $\mu=0.55$ or lower, see Figure 3.3) strongly suggests that the stress regime in the East Flank favors normal faulting.

In addition to our borehole analyses, several studies have mapped spatial variations in the local state of stress or incremental strain by inversion of spatially clustered populations of earthquake focal mechanisms (Feng and Lees, 1998; Unruh et al., 2002). We have already noted in Section 2.1.3 that earthquake focal mechanism inversions predict horizontal orientations consistent with the borehole analyses of Sheridan and Hickman (2004), Geomechanics International (2003), Davatzes and Hickman (2005), Davatzes and Hickman (2006). In addition, the predicted tendency for normal versus strike slip faulting in these studies is also consistent with the stress models inferred from breakouts and hydraulic fracturing stress measurements.

Recent work by Keith Richards-Dinger (pers. comm. 2005) extends these studies to look at details of the strain field in the region of EGS well 46A-19RD. Richards-Dinger has used relocated earthquakes to invert earthquake focal mechanisms for the incremental strain and maps an area of extensional strain located over the southern part of the Main Field and extending east and north into the East Flank. This interpretation is consistent with both the stress and the strain invariants predicted by the previous studies (Feng and Lees, 1998; Unruh et al., 2002), and with local GPS- and InSAR-based surface displacement vectors which indicate subsidence above the
Main Field and East Flank (Fialko and Simons 2000; Wicks et al., 2001; Unruh et al., 2002). Such a strain field favors normal faulting and is characterized by relatively low mean stress, consistent with our observations in the East Flank. This low mean stress is expected to facilitate dilation and increased permeability accompanying fault slip. Thus, the relatively low mean stress predicted by these strain data and inversions for the southern part of the Main Field, where EGS well 46A-19RD is located and where permeability is currently low, is favorable for a successful EGS stimulation. This inferred stress state near 46A-19RD will be tested with a hydraulic fracturing stress measurement and borehole image and other logging planned for 2006.

3.1.1.3 Coulomb failure analysis of fractures visible in image logs of 38C-9

Surface manifestations of fluid flow at Coso clearly indicate a relationship between faults that act as fluid conduits and the current state of stress (Section 2.1.2 Figure 2.1). Therefore, we used GMI•MohrFracst™ to predict critically stressed fracture orientations using Mohr-Coulomb faulting theory and to calculate the effective shear stress and normal stresses acting on each fracture plane given the orientations and magnitudes of the three principal stresses and the formation fluid pressure. Barton et al. (1995, 1998) have shown that optimally oriented, critically stressed fractures control permeability in areas of active tectonics. This suggests that critically stressed fracture sets are likely to be responsible for the majority of the geothermal production in the Coso Geothermal Field. Additional details of this analysis are provided in Appendix E.

Using $S_{\text{hmin}}$ extrapolated from the value measured in the hydraulic fracturing test (Figure 3.3), we used two end-member stress states to bracket the possible range of $S_{\text{Hmax}}$ values. These are a transitional normal to strike-slip faulting model ($S_{\text{hmin}} < S_{\text{Hmax}} = S_{V}$) and a strike-slip faulting model ($S_{\text{hmin}} < S_{V} < S_{\text{Hmax}}$) where $S_{\text{Hmax}}$ is fixed along the $\mu = 0.6$ failure line shown in Figure 3.3. For each of these models we then calculated the ratio of shear to effective normal stress acting on each of the fractures observed in 38C-9 and displayed the results in lower hemisphere, stereographic projections of poles to these fracture planes (Figure 3.4).

In these calculations we used the post-production pore pressure, which resulted in very few critically stressed fractures under current reservoir conditions in Coso 38C-9. We then calculated the amount of reservoir pressure increase needed to trigger frictional failure (slip) on fractures observed in the EMI logs for both of the stress models used. The strike-slip faulting model requires smaller excess pressures (less than 500 psi above ambient) to initiate slip on properly oriented fractures (Figure 3.4b), whereas the transitional normal faulting to strike-slip model requires between 500 and 1000 psi above ambient to initiate slip on properly oriented fractures (Figure 3.4a).

In well 38C-9, the orientation of SHmax is N11°E. As a result, critically stressed faults defined by the transitional normal faulting to strike-slip faulting model strike NNE–SSW and dip approximately 60° either towards the WNW or towards the ESE (Figure 3.4a). Critically stressed fractures in the strike-slip faulting model either dip steeply to the east with strikes that range from NE to NW, or they dip steeply to the west with strikes that range from SW to SE (Figure 3.4b).
Figure 3.4: GMI•MohrFracs analysis results using (a) transitional normal to strike-slip faulting stress model and (b) strike-slip faulting stress model applied to all fractures measured in well 38C-9. The white dots denote fractures that are critically stressed for shear failure for coefficients of friction of 0.6 (after Byerlee, 1978). The terms ambient and +500, +1000 psi denote the amount of excess fluid pressure applied above current, post-production ambient values.

3.1.1.4 Fault rocks
Fault rock mineralogy and texture provide a further control on the formation and maintenance of fluid flow in the geothermal field (Davatzes and Hickman, 2005b) that is not addressed by the above analysis of fault geometry and stress. Core from East Flank well 64-16 reveals two end-member classes of fault rocks at depth: (1) cataclastic fault rocks with mineralogy similar to the host rock but with increased porosity; (2) well-developed clay-rich fault rocks characterized by extremely small, disconnected pores (Davatzes and Hickman, 2005b). These distinct fault zone mineralogies and textures imply variation in the frictional strength, permeability, and slip-induced dilatancy of fault zones (Lockner and Beeler, 2002) within the Coso geothermal field. Whereas we know these different fault types are developing in the geothermal field (Davatzes and Hickman, 2005b), we currently do not have enough data to adequately describe their three dimensional distribution and thus fully incorporate their impact into an EGS stimulation strategy. These issues are presented in detail and discussed in Section 3.1.2.

If the crust in the East Flank is currently critically stressed (Townend and Zoback, 2004), i.e., at incipient shear failure, then at least some faults in these regions have coefficients of friction in the range of 0.3 to 0.55. Such low coefficients of friction are common in clay-rich fault zones, and would be compatible with clays identified in cuttings from well 34-9RD2 (Kovac et al., 2005). In addition, if production causes draw-down in this compartment, fault slip would only be possible on weaker and weaker faults, and thus could inhibit permeability regeneration by dilatant shear failure.

3.1.1.5 Surface hydrothermal activity

Surface expressions of hydrothermal fluid flow in the CGF include steaming ground, fumaroles, and hydrothermal alteration/deposition (Hulen, 1978; Roquemore, 1981; Adams et al., 2000). Earliest surface evidence of geothermal activity in the field is represented by the 307ka travertine deposits (Adams et al., 2000), which is offset by segments of the Coso Wash fault. Subsequently, sinter indicating higher temperature hydrothermal activity was deposited at approximately 238ka (Duffield et al., 1980; Echols et al., 1986; Hulen, 1978). The current hydrothermal activity has developed within the last 10ka and includes fumaroles. Reservoir boiling leading to acid alteration distributed along fault traces appears to be modern (Davatzes and Hickman, 2005b).

These features are preferentially distributed along major NNE-SSW trending normal faults with clear geomorphic expressions such as retaining ponds and fault scarps in basin fill. Intersections between NNE-SSW trending faults and nearly WNW-ESE trending faults (Section 2.1.2 Figure 2.1a) also appear to localize intense hydrothermal activity. These circumstances support they hypothesis that fluid flow is largely focused along the most active faults and fractures in the CGF. However, simple analysis of the fault geometry and stress state does not currently account for variations in the distribution of hydrothermal activity. Other variables such as the physical properties of fault rocks (Davatzes and Hickman, 2005b), reservoir engineering practices, and the complex 3D fault geometry and mechanical interactions between nearby faults under the current stress field will be addressed in a future study.

3.1.1.6 Summary
A faulting regime that is transitional from normal-slip to strike-slip in the East Flank of the field is suggested by hydraulic fracturing stress tests that measure $S_{h\text{min}}$ and constraints on $S_{H\text{max}}$ from borehole breakouts and rock strength. Holocene sediments offset by modern basin-bounding normal faults suggest that normal faults play a major role in the modern deformation field. These results are also consistent with inversions of seismicity in the upper 0.5 to 2.5 km of the field, which indicate that the East Flank and southern portion of the Main Field are actively extending. Hydraulic fracturing stress test results show that the magnitude of $S_{h\text{min}}$ is relatively low and slightly above that predicted for normal faulting failure. However, borehole failure analysis of well 38C-9 (which is equally applicable to 34-9RD2) and simple frictional faulting theory indicate that this value of $S_{h\text{min}}$ and approximate bounds on $S_{H\text{max}}$ are consistent with crustal strength being controlled by normal to strike-slip faulting. Fracture failure analyses using the improved Coso stress model indicate that normal faulting failure will not occur under ambient conditions, but can be induced through increases in reservoir pressure in excess of 500 psi. Strike-slip failure can be induced by lesser increases in reservoir pressure. This tentative conclusion is suggested given that only an upper bounds on the magnitude of $S_{H\text{max}}$ can be derived from the near-absence of breakouts in the East Flank.

### 3.1.2 Geological analysis of fault rock development, mineralogy, and physical properties

In crystalline rock, faults and fractures provide the primary source of permeability. Yet the active precipitation of minerals and chemical alteration in many hydrothermal systems implies that fractures conducting fluids in the subsurface will often seal and permeability will be lost. In contrast, recurrent brittle fracture and frictional failure in low porosity crystalline rocks produce dilation owing to surface roughness along the fracture walls (Brown, 1987) and the formation of breccias and microcracks during fault slip (Lockner and Beeler, 2002). Faults and fractures sealed by the precipitation of common vein-filling minerals such as quartz or calcite retain this brittle (dilatant) behavior, as demonstrated by crack-seal textures in layered veins or the brecciation of fault cements. These processes lead to periodic permeability enhancement associated with reactivation of optimally oriented and critically stressed fractures, which has been shown to be an important mechanism in maintaining high reservoir permeability in some geothermal systems (Barton et al., 1998).

Alternatively, dissolution of crystalline rock by hydrothermal fluids reduces the strength of grain contacts and increases porosity in fracture walls (Boitnott, 2002). Chemical alteration can also produce increasing proportions of clays and other phyllosilicates, which promote ductile behavior and reduce frictional strength (Lockner and Beeler, 2002) while also reducing fault permeability (Crawford et al., 2002). The potential result of these processes is increased ductility of fault rocks that minimizes dilation accompanying slip and prevents regeneration of permeability.

Geothermal systems are commonly recognized to consist of a clay-rich caprock, situated above a permeable reservoir zone, and at greater depth, a plastically deforming zone. In this contribution we explore how mineralogical and petrophysical properties associated with these zones in the Coso Geothermal Field control mechanisms that accommodate deformation and consequently determine the permeability of newly formed or reactivated fractures. We find that the
permeability structure of the Coso Field is likely generated and maintained through a feedback between recurrent fracture slip and fluid flow on one hand and mineral precipitation and chemical alteration on the other.

### 3.1.2.1 Methods

We use several lines of evidence to infer the mechanisms by which faults at Coso form and slip and how this, in turn, controls the permeability structure of the Coso Geothermal Field. Surface outcrops, core, and image logs constrain the geometry, mineralogy, and textures of the structures in fault zones. These data are used to infer the mechanisms of deformation and fault-slip behavior (Davatzes et al., 2005). Modern and paleo-fluid flow within the geothermal field are inferred from the distribution of fluid flow at the surface, temperature profiles, mud loss during drilling, and the distribution of seismicity. Fluid flow data and deformation data are cross-correlated to establish the relationship of fault zones to fluid flow.

### 3.1.2.2 Fault-rock development

The textural and mineralogical evolution of fault rocks is revealed by detailed analysis of core from well 64-16 and surface examples of exhumed fault zones. Previous studies have revealed that the minerals that comprise fault rock, their grain shapes, and packing geometry are important controls on fault zone properties such as permeability (Crawford et al, 2002), frictional strength, and slip behavior (Lockner and Beeler, 2002). Our initial examination of the mineralogy and microstructure of fault rock at Coso reveals three fault rock types (Davatzes and Hickman 2005b): (1) Fault rock consisting of poorly sorted dilatant breccia, characterized by large variations in grain packing (pore size), and calcite crack-seal textures. (2) Fault rock consisting of amorphous silica and zeolites that contains large connected pores, dilatant brittle fractures, and dissolution textures. (3) Fault rock consisting of foliated layers of chlorite and illite-smectite separated by slip surfaces. As indicated above, these different fault rocks are respectively associated with a high permeability convectively heated reservoir zone in the geothermal system, a shallow region of boiling promoting acid alteration and dissolution of the rock mass, and a conductively heated “caprock” at moderate to shallow depth associated with low permeability.

We used outcrop and hand-sample scale mapping, XRD analysis, and SEM secondary electron images of fault gouge and slip surfaces at different stages of development (estimated shear strain) to investigate the processes responsible for the development and physical properties of these distinct fault rocks. The initial results of these analyses are as follows:

(A) Brecciated, dilatant, calcite rich fault zone: Breccia and dilatant fractures dominate in the damage zone of the Coso Wash normal fault (Figure 3.5a) exposed NNE of the Coso Wash Hot Springs. At that location, the damage zone is comprised of a series of small faults and fractures that mirror the local orientation of the modern fault scarp in the basin sediments. Many of these fractures contain fibrous veins more than 10 cm thick (Figure 3.5b) consistent with deposition into void space. Dilatant (tensile) fractures also occur in association with sheared fractures (Figure 3.5c). In general, the tensile fractures abutt the sheared fracture at an angle approximately between 50º and 75º and are anti-symmetrically distributed about it. This
geometry and age relationship is consistent with the formation of splay fractures that propagate in response to tensile stresses concentrated at the tip or at asperities of a slipping shear fracture (Davatzes and Aydin, 2003). Splay fractures are densest in extensional steps between two overlapping, *en echelon* sheared fractures (Figure 3.5c) where they define fracture-bounded rhombs of rock. Shearing of fractures healed by precipitation (Figure 3.5d) is associated with the rotation of the fracture-bounded volumes and the formation of breccia, indicating that fracture porosity is regenerated following healing.

![Figure 3.5](image)

**Figure 3.5:** (a) Geologic map of the Coso Wash fault scarp and zones of massive veins and breccia in granodiorite (location Section 2.1.2 Figure 2.1). Detailed photos of damage zone structures including: (b) layered carbonate vein, (c) dilatant fractures (splay fractures) localized between sheared fractures, (d) breccia and associated splay fractures.

A similar progression with increasing shear strain is revealed by core from well 64-16 (see Section 2.1.2 Figure 2.1 for location). Fault zone development is associated with repeated episodes of brittle failure, shearing, and healing for this type of fault zone (Figures 3.6 and 3.7). Damage of the intact crystalline rocks is first comprised of a series of small faults and fractures (Figure 3.6, t₁). As in the outcrop case, dilatant (tensile) fractures are often anti-symmetrically distributed about sheared fractures at angles approximately between 50° and 75° (Figure 3.7, t₂) where they define fracture-bounded rhombs of rock and localize dilatancy. Also like the outcrop case, fractures formerly healed by precipitation are reactivated and associated with the rotation of these fracture-bounded volumes resulting in the formation of breccia, (Figure 3.7, t₃). In some cases, development of multiple sets of cross-cutting cements in fault-hosted breccias indicates successive episodes of fault reactivation, brittle fracturing/dilatancy, and healing (Figure 3.7, t₄).
**Figure 3.6:** Initial failure of low porosity granitic rocks typical of the Coso Geothermal Reservoir typically includes macroscopic fracture and dilation visible in core from well 64-16 in the East Flank. Vertical white line is one inch long.
Figure 3.7: Core samples demonstrating the progression of deformation and healing in cataclastic fault rock obtained from well 64-16. From right to left are examples of faults with increasing shear strain.

Characteristics of slip surfaces and adjacent fault gouge from these cataclastic fault zones were examined using outcrop samples from the Spring View Breccia (see Section 2.1.2 Figure 2.1 for location) (Whitmarsh, 1998a) and are illustrated in Figure 3.8. The pore size distribution in the quartz-rich fault rocks is bimodal. Large pores (10 microns to 1 mm) are present in the brecciated fault gouge immediately adjacent to the polished slip surface while smaller pores (~1-10 microns) are present within the fine-grained gouge material coating the slip surface itself (upper-left image of Figure 3.8, upper series of images) commensurate with the grain size but varying slightly related to the efficiency of grain packing. This cataclastic gouge is composed of angular grains consistent with abrasive wear localized over the small areas of contact along the slip surface. In this case, the gouge thickness is only a few millimeters and probably represents an early stage of gouge and slip surface development.

In thicker zones of silica-rich gouge associated with more well-developed fault strands (Figure 3.8, lower series of images), bands of relatively small, similarly sized, and well-packed grains are oriented normal to the direction of slip indicated by slickensides (red arrow in Figure 3.8).
These bands appear to migrate along the slip surface in the direction of shear. Surrounding these bands are poorly sorted, loosely packed angular grains. We tentatively interpret these bands to represent newly formed fault gouge along the active slip surface. In these thicker gouge zones, pore size is also bimodal. Pores in the “bands” are small and related to the grain size; however, between bands, pores are still many times the grain size, and remain connected both across and along the slip surface.

**Figure 3.8**: Scanning Electron Microscopy (SEM) secondary electron images of chips of fault rock in cataclastic fault gouges rich in quartz and feldspar. Bottom left image is an EDS element spectra which qualitatively indicates the dominance of silica and oxygen, presumably quartz or amorphous silica, in the fault rock.

(B) Pervasively altered fault rocks rich in clays, zeolites, and silica due to acid alteration: An example of an acid-altered fault zone is exposed by excavation of the mercury mine at the Nicol Prospect (Figure 3.9; see Section 2.1.2 Figure 2.1 for location). The fault core (the part of the fault that accommodates most of the deformation and shear strain) is comprised of gouge rich in amorphous silica with associated chlorite, illite, and zeolites and isolated breccia clasts of altered host rock (Figure 3.10). The core of the fault is surrounded by highly fractured rocks comprising a damage zone with minor mineralization and small slickensided faults exhibiting several centimeters of down-dip (normal faulting) slip. Note also that kaolinite is absent from the slip surface, in apparent contrast to the breccia zone discussed in the 2005 second quarterly report. Intense alteration is primarily confined to the fault core and becomes less intense with greater distance from the slip surface. Most major rock-forming minerals such as hornblende and biotite are absent in the fault gouge (XRD pattern in Figure 3.10) although these are common rock-forming minerals in the surrounding host rock. However, remnant Potassium-Feldspar and quartz persist in the fault rock. In the breccia clasts, these minerals appear to have been leached out, increasing the porosity, and were partly replaced with alteration phases (XRD pattern of Figure 3.10) and amorphous silica.
The gouge zone contains a through-going striated slip surface and subsidiary shorter slip surfaces (Figure 3.9). The through-going slip surfaces are coated by and incorporate microspheres of amorphous silica (Figure 3.10 bottom inset and 3.11a). Below this coating, the gouge is composed of slightly foliated platy clays, chlorite, and zeolites. The localized coating of the through-going slip surfaces by spheres of amorphous silica indicates that the silica was precipitated while suspended in flowing water moving along the slip surfaces. Taken together, the distribution of alteration and the occurrence of the microspheres is consistent with fluid flow primarily focused along the slip surface and bleeding out into the surrounding gouge and fractured damage zone.
Figure 3.10: SEM secondary electron images and X-Ray Diffraction (XRD) spectra from a slip surface obtained from a pervasively altered fault zone rich in amorphous silica (broad peak from 15 to 30 2θ) and zeolites/illite exposed at the Nicol Prospect. SEM images discussed in Figure 3.10. Location of sample indicated in Figure 3.9.

Figure 3.11: SEM secondary electron images of rock chips from the fault zone. (a) Upper series of images are from the primary slip surface of the fault zone in Figure 3.9. They show a striated slip surface underlain by zeolite and clay-rich gouge with minor foliation development. The slip
surface is coated with lepispheres that merge together over time (two images in upper right) as amorphous silica locally dissolves and re-precipitates. Long tube-like structures are bacteria that live in the upwelling fluids in the fault zone and help mediate silica precipitation. (b) Along the bottom row are materials from the breccia zone (Sample location in Figure 3.9). Note that most primary minerals have been leached away leaving a hollow framework of clays and zeolites. In the right-hand image, a concoidally fractured quartz grain is the sole remaining primary mineral.

(C) Chlorite-smectite rich fault zone: The third fault zone type is distinguished by a fault core dominantly composed of chlorite and illite-smectite. Early development of these fault zones is similar to the previous examples with dilatant failure of the crystalline host rock associated with splay fracture and potentially the development of breccias (Figure 3.7, t1). However, subsequent to initial failure, fault rock development is dominated by the progressive alteration of the host rock and the precipitation of clay minerals (Figure 3.12, t2). Adjacent to the fault core, deformation in the country rock is associated with dilatant fracture—several of which are healed by calcite (Figure 3.12, t3). These fractures have the geometry of the splay fractures interpreted in Figures 3.5c and 3.7, but are confined to the host rock and do not develop in the clay-rich fault rock. At higher shear strains we note breccia and brittle fractures in the damage zone that are well-connected and dense, but also do not extend across the fault core (Figure 3.12, t4).

X-Ray Diffraction (XRD) spectra indicate fault rock is rich in chlorite and illite-smectite defining a clay-rich fault core and associated slip surfaces (Figure 3.13). Within the shear zone the chlorite shows foliation subparallel to the fault strike and dip (Figure 3.14). The textural relationship of the fault rock to the breccia blocks at the margins of the fault core indicates relatively ductile deformation by folding of foliated chlorite and smectite around breccia clasts and extrusion of clay into mesoscopic void space (Figure 3.14, core map at top). Multiple, linking slip surfaces are distributed across the fault core and anastomoze around more intact blocks of the host rock (Figure 3.14). Shear appears to be localized in the clay-rich fault rock, while the boundaries of the shear zone continue to undergo brittle failure that can continue breccia development along the margins of the fault core. These processes suggest that the fault zone can thicken by both continued alteration/precipitation of clays in the core and brittle deformation in the damage zone.
Figure 3.12: Core samples from well 64-16 demonstrating the progression of deformation and alteration during development of clay-rich fault rock. Shear strain increases from left to right.
Figure 3.13: SEM secondary electron images and XRD of slip surfaces obtained from core at 990 ft MD in well 64-16 of a chlorite-smectite rich fault zone. SEM images show well-developed striated slip surfaces typical of clay-rich fault rocks sampled at Coso. Detailed discussion of these images is associated with Figure 3.14.

Slip surfaces are polished and coated by illite-smectite and chlorite (Figure 3.14). In detail, the gouge is composed of many slip surfaces separating very thin laminations, or layers, of chlorite or illite rich gouge (Figure 3.14). Illite grains are generally equant and range in size from 0.05 to 2 microns, whereas chlorite grains are platy and reach in-plane dimensions of 10 microns. Porosity of these fault rocks is relatively low, and pores appear to be small and largely isolated within the clay gouge. The pore geometry in clay-rich fault rock adjacent to the slip surfaces is bimodal (Figure 3.14). Large pores (10’s of microns) occur along the margins of gouge layers where separated by striated slip surfaces, whereas pore dimensions in the interior of the gouge layers are fairly uniform and less than or equal to about 0.1 micron. The largest pores are located at the terminations of gouge layers and are associated with euhedral, platy chlorite grains that preferentially nucleate along the striations and grow into the adjacent larger-sized pores (e.g., Figure 3.14), potentially at the edges of gouge layers. These mineral grains are incorporated into the gouge through rotation, folding, and compaction evident at the edge of gouge layers (Figure 3.14).
Figure 3.14: At the top is a core map of a clay-rich fault zone from 990 ft MD in well 64-16 illustrating some of the salient macroscopic characteristics of clay-rich fault zones. Along the bottom SEM secondary electron images of slip surfaces from 645 ft MD and 990 ft MD in well 64-16. These structures represent a progressive development from poorly developed ($t_1$ through $t_3$), short slip surfaces, to more extensive through-going boundary shears ($t_4$) at higher shear strain. ($t_1$) Development of a slip surface with, from right to left, (1) euhedral chlorite grains growing into open pore space, (2) a poorly developed slip surface formed by the folding, comminution and partial shearing of chlorite grains with poor grain packing, (3) a well-developed slip surface with the precipitation of new illite grains on top of it. ($t_2$) Detailed image of the contact of the slip surface in $t_1$, showing newly precipitated chlorite grains that appear to be rotating and folding underneath the developing slip surface. ($t_3$) Multiple layers of gouge that are separated by striated slip surfaces. Each of these layers records a different direction of slip (green arrows) at the scale of about 20 $\mu$m. ($t_4$) Well-developed slip surface acting as boundary shear in the fault zone mapped above.

3.1.2.3 Surface fluid flow

Surface expressions of fluid flow in the East Flank region include steaming ground, fumaroles, and hydrothermal alteration/deposition (Hulen, 1978; Adams et al., 2000). These features are distributed along major NNE-SSW trending structures and are localized at intersections between NNE-SSW trending faults and nearly WNW-ESE trending faults (Section 2.1.2 Figure 2.1). These faults appear to be well oriented for slip in the current stress state and offset of Quaternary fill also suggests recent slip (see Section 2.1. for discussion). These circumstances suggest that fluid flow is largely dominated by the most active faults and fractures in the CGF. In addition, intense hydrothermal activity at some fault intersections might suggest focusing of fluid flow along active faults where fault interactions promote dilatant failure that would increase and maintain permeability.

3.1.2.4 Subsurface fluid flow inferred from temperature and fluid inclusions
In the subsurface, variations in temperature gradient across 1-D cross-sections of the geothermal field provided by wells such as 58A-10 can be used to interpret changing permeability and fluid flow (Figure 3.15). Regions of high temperature gradient imply more conductive heat transfer and limited permeability that typically define a shallow cap rock to the geothermal field (Zone 1 in Figure 3.15). In contrast, regions of near-isothermal temperature gradient imply convective heat transfer and high permeability associated with the geothermal reservoir underlying the cap rock (Zone 2). In well 58A-10 the transition from a shallow conductive region to a deeper convective region is marked by distinct changes in the temperatures recorded by fluid inclusions and by their gas chemistry (Moore et al., 2004). Above the transition at ~4300 ft measured depth (MD), temperature inferred from fluid inclusion homogenization temperatures cluster tightly about temperatures measured from the borehole. Below the transition, fluid inclusion temperatures clearly fall below the modern temperature.

Figure 3.15: Temperature from wireline logs and computed temperature gradient, mud loss zones from drillers log, fluid inclusion temperature and gas chemistry (Moore et al., 2004), and stress orientations from our analysis of image log data in well 58A-10.

In addition, fluid flow along faults is also indicated by perturbations in borehole temperature logs (see discussion in Barton et al., 1998) and mud losses that coincide with faults visible in image logs (see example from well 58A-10 in Figure 3.15). In 58A-10, perturbations of the temperature gradient are associated with clear changes in fluid inclusion gas chemistry, including the Ar/He
ratio, abundance of CO$_2$, and the CO$_2$/CH$_4$ and Alkane/Alkene ratios. Image logs indicate stress rotations and fault zones at all of the major transitions (Davatzes and Hickman, 2005a, Davatzes and Hickman, 2006). The concurrence of temperature gradient anomalies, fluid inclusion gas chemistry perturbations, and stress rotations all indicate an influence of faults on the circulation of subsurface fluids and indicate preferred fluid flow along faults.

It is more difficult to determine where faults act as barriers to fluid flow, although this can be inferred from borehole temperature logs in addition to the distribution of seismicity. The repeat temperature logs from well 58A-10 (Figure 3.15) distinguish two zones of high temperature gradient labeled zones 1 and 3. These high temperature gradients suggest conductive heat transfer and low permeability, despite fracture densities and orientations similar to zone 2, where convection dominates (Davatzes and Hickman, 2005a, b). Another important aspect of zone 2 is the presence of very small but abrupt changes in geothermal gradient across faults (labeled as sub-zones A-E in Figure 3.15). These small-scale transitions in gradient are consistent with these faults acting as limited, or transient, barriers to fluid flow. Several of these faults also separate domains of different fluid inclusion gas chemistry. The separation of zones distinguished fluid inclusion gas chemistry and/or temperature gradients at faults visible in the image logs indicate locations where faults act as barriers to across-fault fluid flow.

In addition, locally high rates of seismicity within the actively produced Coso Geothermal Field and the spatial association of this seismicity with boreholes suggest that most micro-earthquakes are probably related to fluid pressure variations induced by fluid production or injection (Feng and Lees, 1998). However, sharply defined margins to this otherwise diffuse seismicity coincide with faults visible at the surface (e.g., Section 2.1.1 Figure 1.3 and Section 2.1.2 Figure 2.1). These sharply defined terminations of seismicity indicate that these faults act as barriers to fluid flow, limiting the spatial extent of fluid pressure variation and effectively compartmentalizing the Coso Geothermal Field.

In most locations, faults display indications of both focused fluid flow and barrier behavior. One example is the fault seen at 6900 ft in well 58A-10 (Figure 5), which was associated with significant mud losses while drilling and persistent negative temperature gradients. This fault also separates adjacent sub-zones of distinct temperature gradient. Similarly, the Coso Wash normal fault system (Section 2.1.2 Figure 2.1) hosts fumaroles but also defines the margins of earthquake clusters (e.g., Section 2.1.1 Figure 1.3 and Section 2.1.2 Figure 2.1). In both cases fluid flow across the fault appears to be inhibited, whereas fluid flow along the fault is enhanced.

### 3.1.2.5 Types of faults visible in image logs and their depth distribution

A detailed examination of the locations where faults have an important impact on fluid flow indicates an association between fault zone permeability and the clay content of fault zones. We were able to interpret the distribution of clay/alteration mineralogy from cuttings (including new XRD observations and data from mud logs) and the textural attributes of fault zones visible in BHTV and FMS image logs (Figure 3.16). Although these mineralogical analyses are still in progress, preliminary results indicate that clay-rich fault zones identified in cuttings are often associated with foliated textures in image logs, and enhanced micro-conductivity in FMS images.
(darker areas in Figure 3.16). These textures are similar to those we have examined visually in core from well 64-16. Initial results indicate that these fault zones are generally associated with anomalous zones in wireline logs indicating increased caliper dimensions, reduced sonic velocity, anomalous neutron porosity, and increased natural gamma.

Figure 3.16: Comparison of fault zone in FMI image log of well 58A-10 to core of a clay-rich fault from well 64-16.

In general, our analysis also shows that regions of conductive heat transfer are dominated by clay-rich fault rocks (e.g., faults at 2690 and 3861 ft MD in Figure 3.17). Similarly, clay-rich fault rocks also appear to be associated with faults that separate zones of distinct temperature gradient or fluid inclusion gas chemistry (e.g., fault at 6212 ft MD in Figure 3.17). Thus far, XRD analyses of these zones are associated with spikes in clay content, or in the case of excessive washing of cuttings (typical of 58A-10), they demonstrate a loss of mafic minerals, plagioclase, and feldspar, presumably depleted through hydrothermal circulation, leaving an enriched signal in quartz. These clay-rich and hydrothermally depleted faults are essentially absent in zones of convective heat transfer where open fractures dominate (e.g., faults at 4712 ft MD and 7722 ft MD in Figure 3.17). In these convective regions, fault zones generally display cataclastic textures or clean fracture lines in borehole image logs, and are often associated with high fracture densities (Davatzzes and Hickman, 2005a).
Figure 3.17: Acoustic and Resistivity images of representative fault zone types and their locations relative to mud loss zones, temperature and temperature gradient.

3.1.2.6 Conceptual model of fluid flow and fault mechanics in the Coso geothermal system

The distribution of active fumaroles and steaming ground at the surface (Section 2.1.2 Figure 2.1) indicate that fluid flow is primarily associated with active fault segments trending NNE and at intersections between fault segments. However, not all of the faults (or fault segments) seen at Coso appear to be permeable. For example, the temperature profiles (Figures 3.15 and 3.17) and geologic well log from well 58A-10 suggest that the conductive zone of low fluid flow (zone 1) is associated with abundant clay mineralization, in contrast to the convecting zone (zone 2) which is associated with calcite precipitation and little alteration.
Furthermore, the mineralogy and texture of the different fault zones identified at Coso (Figures 3.5 through 3.14) indicate the role of different deformation mechanisms and structural/geochemical history. For example, faults healed by the precipitation of calcite and related minerals continue to undergo brittle dilation when reactivated and thus regenerate permeability (Figure Figures 3.5, 3.6). In contrast, the introduction of chlorite and other sheet silicates such as smectite appear to promote ductility and thereby minimize dilatancy of the fault rock during shear (Figure 3.12 and 3.14). In the following sections we discuss the relationship of the deformation mechanisms that control fluid flow to the deformation environments defined by the shallow ground water system, clay-rich caprock, reservoir interval, and partial melt that define the Coso Geothermal System. This discussion is indexed to the four zones shown in Figure 3.18.

**Figure 3.18:** Schematic showing how cycles of deformation and chemical reactions along faults can control the evolution of fault zone strength, frictional behavior, and hydrologic properties.

**Zone 1. Shallow groundwater flow:** In the shallowest zone, groundwater flow circulates through a network of diffusely distributed fractures associated with active faulting and dilatant failure facilitated by low confining stress. Rising geothermal fluids or boiling in areas of high heat flow and slow recharge exsolve gases that can mix with shallow groundwater, potentially lowering the pH and promoting mineral dissolution (Facca and Tonani, 1967). Dissolution of major rock-forming minerals such as feldspar, plagioclase, hornblende, pyroxene and biotite should initially increase fault zone permeability. This overall gradual increase in permeability will be augmented by sudden permeability increases induced by dilatancy accompanying episodic fault slip (spikes in Figure 3.18).

**Zone 2. Caprock:** The caprock is characterized by conductive heat flow and minimal circulation of fluid. Initial fault formation and slip is the result of brittle-dilatant failure. However, continued slip and fluid flow leads to the formation of smectite phases and chlorite that inhibit dilation accompanying slip. Pores in clay-rich gouge are small (< 0.01 micron) and poorly connected. In the examples examined thus far, pore dimensions correspond directly with the grain size of the clay gouge and the thickness of gouge layers separated by slip surfaces. The key aspects of clay
gouge development are the formation of multiple slip surfaces and the precipitation of new clay minerals in the open pores adjacent to gouge layers that are subsequently sheared and compacted into a new gouge layer.

Alteration is greatest in the fault core and decreases into the host rock. As a result, any damage outside the fault core in unaltered rock remains dilatant. Consequently, fault-parallel permeability increases as cross-fault permeability decreases. The net result is the progressive development of faults with low cross-fault permeability and enhanced fault-parallel permeability. Although permeability might increase in the fault damage zones, the intersection of non-parallel (e.g., conjugate) fault cores truncates the damage zone, leading to a caprock with low overall permeability. Over the lifetime of the geothermal system, continued alteration should further isolate and reduce the size of zones of dilatant failure that generate fracture permeability.

The vertical permeability seal provided by this “clay-rich cap” could be breached by the development of (1) new fault networks or (2) localized dilation related to fault geometry. New fault networks form when there is a sudden change in tectonic stress that is unfavorable for reactivation of an established fault network. Because alteration is primarily localized along the older fault networks, new faults will principally propagate through nearly unaltered rock that favors brittle failure. Owing to the low frictional strength of most clays (Lockner and Beeler, 2002), large rotations of the stress state are required to create new faults in a clay-rich cap, suggesting that breaching of the cap rock by new fault networks will be more difficult. Also, mechanical interaction of fault segments at extensional steps or intersections can locally produce more tensile mean stress that promotes dilatant failure (Davatzes et al., 2005c). This mechanism could produce a pathway for fluids to migrate from reservoir depths to the surface along parts of faults—essentially breaching the cap rock.

Zone 3. Reservoir zone: The reservoir zone is dominated by brittle fracture, brecciation, and cataclasis. Healing primarily occurs by the precipitation of calcite or silica (potentially promoted by convection). In general, the near absence of clays and other phyllosilicates in the reservoir zone prevents the formation of a persistently low-permeability fault core. Thus, across-fault as well as along-fault permeability will be regenerated by periodic fault slip (Figure 3.18). In detail, reduced grain size in the fault core due to cataclasis increases the area of fresh mineral surfaces and the rate of chemical reactions and precipitation on those surfaces. This suggests that the core of reservoir faults will heal faster than the damage zone during the inter-seismic period and thus produce transient across-fault barriers or low-permeability zones (Byerlee, 1993). Consequently, convection can be temporarily confined within isolated damage zones resulting in small steps in temperature gradient (shown diagrammatically in Figure 6b), even though these transient seals will be periodically ruptured so that the permeability within the reservoir remains generally high.

Zone 4. Crystal-plastic deformation below the brittle-ductile transition: As temperature increases with depth and proximity to the heat source, crystal plastic deformation becomes the dominant means of accommodating strain. Large earthquakes can locally extend the depth of micro-seismicity (as indicated by the jagged top of the brittle-ductile transition in Section 2.1.1 Figure 1.2) by locally increasing the strain rate. However, the permeability of fault and country rock in this zone is expected to be quite low.
3.1.2.7 Summary

The feedback between fracture slip, the generation of permeability, fluid flow and alteration suggests that fracture permeability will evolve concurrently with the geothermal system. Initial fracture development in un-altered crystalline rocks will enhance permeability and allow the circulation of fluids, the transfer of heat, and initiate chemical alteration. Chemical alteration will eventually lead to the breakdown of rock forming minerals and alteration to clays within appropriate temperature and pressure conditions. The presence of clay in the cap rock mitigates the ability of fracture slip to generate permeability and consequently isolates a deeper geothermal reservoir from the surface. In contrast, in reservoir rocks permeability is maintained in fracture systems of calcite- or silica-dominated fracture sealing through dilatancy accompanying episodic slip despite exposure to the same stress state and deformation conditions as in the cap rock.

Earlier observations suggest that the geometry of active faults in relation to the local state of stress provides one driving mechanism to develop and maintain regions of focused fluid flow in the Coso Geothermal Field (Sheridan et al., 2003; Sheridan and Hickman, 2004). However, our observations indicate that fault rock mineralogy and texture provide a further control on the formation and maintenance of fluid flow in the geothermal field. The evolution of this mineralogy and its impact on the evolution of geothermal systems and fault mechanics is a focus of ongoing research.

Mineral stability is a function of hydrostatic and non-hydrostatic, temperature, fluid flow, and fluid chemistry conditions. Which minerals form, and the rates at which they grow is also a key element in determining variations in the magnitude and anisotropy of fault zone properties at Coso. Consequently, we suggest that the development of fault-zone properties depends on the feedback between deformation, resulting changes in permeability, and large-scale fluid flow, leading to dissolution or precipitation of minerals in the fault rock and adjacent host rock (summarized in Figure 1.4) resulting in a dynamic and evolving geothermal system as illustrated by the conceptual model in Figure 3.18. The implication for Coso is that chemical alteration of otherwise low-porosity crystalline rocks appears to determine the distribution and temporal evolution of permeability in the actively deforming fracture network at small to moderate scales as well as along major, reservoir-penetrating fault zones.
3.1.3 References


Echols, T.J., Hulen, J.B., Moore, J.N. and Crane, G. K. (1986), Surficial alteration and spring deposits of the Wheeler mercury prospect, with initial results from Wheeler Corehole 64-16,


Moos, D. and Zoback, M.D., (1990), Utilization of observations of well bore failure to constrain the orientation and magnitude of crustal stresses: Application to continental, deep sea drilling project, and ocean drilling program boreholes, Journal of Geophysical Research, 1000(B), 12791-12811.


the Coso geothermal field. 28th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 27-29, SGP-TR-173, 16 p.

Sheridan, J. and Hickman, S., (2004), In situ stress, fracture and fluid flow analyses in well 38C-9: An enhanced geothermal system in the Coso geothermal field, 29th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 26-28, SGP-TR-175, 8 pp.


Townend, J., and Zoback, M.D. (2004), How faulting keeps the crust strong. Geology, 28, 399-402.


Whitmarsh, R.C. (1998a), Structural development of the Coso Range and adjacent areas of eastern California [Ph.D. thesis]: Lawrence, Kansas, University of Kansas.


### 3.2 Geochemical Modeling of the Fluid Mineral Interactions Leading to Permeability Changes (Mike Adams and Katie Kovac)

#### 3.2.1 Continuous monitoring of enhanced permeability using natural tracers

The current EGS paradigm involves artificially increasing permeability in natural systems using hydrofracturing techniques. Permeability may increase or decrease once the hydrofracturing has taken place as the fractures adjust to their new configuration. Artificial tracers can be used to periodically measure changes in the permeability. It is also desirable to measure any gains or losses continuously (or as often as one wishes to take and analyze a sample) using compounds that are naturally present in the injection water. This method is contingent on there being a compositional difference between the injection and production waters.

Most of the constituents of geothermal water are unsuitable for this method in the quantitative sense because they are involved in ion exchange or precipitation/dissolution reactions. In addition, none can be used by themselves because of variations in the salinity of the liquid fraction caused by variable boiling in and around the production well. These variations are canceled out when a ratio of two constituents is used.
Chloride and boron appear to be the best choices as conservative natural tracers. Geochemists have long used the ratio of chloride to boron to determine the origin of waters (Arnorsson and Andresdottir, 1995). The basis for their use is that boron and chloride are among the most conservative aqueous species, as demonstrated by the close resemblance of the aqueous and host rock ratios (Ellis and Mahon, 1964; Ellis and Mahon, 1967) and the homogeneity of the ratio among fluids derived from a common reservoir (Shaw and Sturchio, 1992). The reservoir water in the Coso East Flank has a ratio that is consistently 40 (with the exception of instances of strong reservoir boiling, discussed below). In the geothermal power plants, some of the boron but almost none of the chloride is transferred to steam during boiling. The result is that the separated brine still has a Cl:B ratio near 40 but the steam condensate has a ratio between 0 and 10. Injection into 34-9 tends to be more condensate because of its peripheral location in the Coso field.
The variations of the Cl/B ratio over the last several years were examined to get a qualitative estimate of the signal to noise ratio. Figure 3.19 shows the variations in the wells on pads 34-9 and 38-9, and for well 73A-18 for comparison. In general, the ratio of chloride to boron is constant for a given area and well at Coso (ADAMS et al., 2000). Well 73A-18 is an example of this. However, it can be seen in Figure 3.19 that the ratio in wells 38-9 and 38A-9 plunged to very low values from 1997 to 2001. These departures from the reservoir ratio have been explained by the development of a steam zone in the reservoir. This can result in the mass transfer of boron from enriched steam to water as these phases ascend in the well bore (ADAMS, 2004). This paper is included in Appendix G of this report.

The use of the Cl:B ratio as a natural tracer may still be viable in these wells because the ratios appear to be returning to reservoir values. However, we will not be certain of this until more recent samples are obtained from these wells.

The compositions of groundwater in the vicinity of the Coso field have also been examined. They have Cl:B ratios that are nearly double that of the Coso East Flank waters. This will enhance the utility of the natural tracer method if these waters are used as injectate in the Coso EGS experiment.

![Figure 3.19. Variations in the ratio of Chloride to Boron in water from the 34-9 and 38-9 well pads over the last several years. Data from well 73A-18 is shown for comparison.](image-url)

### 3.2.2 Analytical modeling of changes in permeability due to fluid-mineral interactions

#### 3.2.2.1 Background and objectives
An examination of potential changes in permeability due to fluid-mineral interactions from the injection waters used at Coso has been undertaken in support of this EGS program. Fluid-mineral reactions are an inevitable consequence of injecting cool water into a hot geothermal reservoir. The character of the interaction depends on the water that is injected and the difference in temperature between the injectate and the reservoir. Two compositionally distinct fluids have traditionally been used for injection, flashed reservoir fluid and condensate, although in EGS systems, low temperature groundwaters may represent an alternative source of fluid. Because the flashed reservoir fluid may contain high concentrations of silica, permeability degradation in the near-wellbore environment is possible. Two different approaches are commonly used to mitigate this effect. The fluid can be injected at temperatures above 150°C to avoid precipitation of amorphous silica in and around the wellbore. Alternatively the flashed fluid can be acidified with sulfuric acid to inhibit precipitation of silica. This treatment is based on research originally performed at the Salton Sea geothermal field (Grens and Owen, 1977). Both methods are utilized at Coso. Although deposition of silica may still occur, it is more likely to be dispersed over a relatively large volume of the reservoir surrounding the wellbore. Condensate, in contrast, has a very low salinity and therefore can be expected to dissolve minerals within the reservoir rock. It requires no treatment to be used as an injectate. Another possible source of injection water is groundwater from outside the geothermal system. At The Geysers, CA, the injection of treated effluent and lake water from nearby population centers has been extremely successful (Goyal, 1999). Injection of groundwater from a low-temperature aquifer overlying the Dixie Valley geothermal system in Nevada has met with similar success (Benoit et al., 2000).

Direct observations on the chemical reactions related to injection have been limited because reservoir rocks affected by injection are seldom sampled. Some research has been conducted on the treatment and behavior of injection waters from the Salton Sea, USA (e.g., Harrar et al., 1979), Cerro Prieto, Mexico (Iglesias and Weres, 1981), Otake, Japan (Itoi et al., 1989) and high-temperature Icelandic geothermal systems (Gunnarsson and Arnorsson, 2003). Research specifically targeted at the injection of groundwater and low-temperature geothermal waters have been carried out by Bruton et al. (1997) and Kristmannsdottir et al. (1989).

The objective of this research is to use reaction path chemical modeling to characterize the potential interactions of the various compositions of injectate in this EGS experiment. The results of these simulations are presented in a separate report (Adams, 2005).

### 3.2.2.2 Modeling results

Chemical models of injection at Coso were constructed using measured injection compositions from well 34A-9 and reconstructed reservoir water from well 38B-9. Aluminum and magnesium concentrations were estimated by assuming equilibrium with reservoir minerals. Conductive heating and mixing of flashed brine, condensate, mixed brine/condensate, and groundwater with reservoir water (38B-9) were simulated using the reaction path modeling program REACT. These variables were grouped to simulate high and low permeability conditions. In the simulations the primary scaling minerals were silica polymorphs in the case of brine and mixed brine/condensate, and anhydrite, calcite, and/or dolomite for groundwater injection. The amount of scaling for a given injectate composition depended on the amount of mixing relative to the temperature increase. The results of the simulations are shown in Appendix H.
3.2.3 Numerical simulation modeling of mineral dissolution and precipitation processes

3.2.3.1 Background and objectives

The objective of this work is to develop an understanding of the geologic setting of the East Flank of Coso, and how it impacts EGS development. Specifically, by gathering petrologic and petrographic data, and incorporating them into a reactive geochemical transport model, the chemical effects of injection can be better understood. Chemical interactions between host rocks and injection fluids can greatly impact the performance of HFR (hot fractured rock) and HDR (hot dry rock) reservoirs over both the short term and long term, by directly affecting porosity and permeability (Durst, 2002 and Bachler, 2003, Xu and Pruess, 2004), but until recently these effects have not been studied. At Coso, field experience indicates that amorphous silica precipitation could be problematic; in a nearby Coso well, scale consisting of mostly amorphous silica was identified (McLin et. al, 2006). Here our present model is described, and also the precipitation kinetics of silica polymorphs is discussed.

Objectives

- Adapt the TOUGHREACT ‘minc’ modeling process to model injection into an East Flank injection well
- Input lithologic, mineralogic, and geochemical data and observations from East Flank wells into the model
- Update kinetic parameters as appropriate to geothermal conditions
- Perform sensitivity studies on the model, and compare model results to literature values
- Obtain initial model results for observations up to 10 years after injection

3.2.3.2 Modeling approach

The present simulations were carried out using the non-isothermal reactive geochemical transport code TOUGHREACT (Xu and Pruess, 2001; Xu et al., 2004). This code was developed by introducing reactive chemistry into the framework of the existing multi-phase fluid and heat flow code TOUGH2 V2 (Pruess et al., 1999). More information on TOUGHREACT can be found at the website (http://www-esd.lbl.gov/TOUGHREACT/). Interactions between mineral assemblages and fluids can occur under local equilibrium or kinetic rates. The gas phase can be chemically active. Precipitation and dissolution reactions can change formation porosity and permeability, and can also modify the unsaturated flow properties of the rock. This simulator can be applied to 1-, 2-, and 3-dimensional porous, fractured media with physical and chemical heterogeneity. It can deal with any number of species present in liquid, solid, and gaseous phases.

3.2.3.3 Modeling results
**Simulation setup**

**Fluid and Heat Flow Conditions**

The geometry and fluid and heat flow conditions were modeled after those described in Xu and Pruess (2004). A one-dimensional MINC (multiple interacting continua) model was used to represent the fractured rock. The MINC method can resolve “global” flow and diffusion of chemicals in the fractured rock and its interaction with “local” exchange between fractures and matrix. Details of the MINC method for reactive geochemical transport are described by Xu and Pruess (2001). Two different mineral zones were considered: 1) a zone representing the relatively impermeable, unaltered host rock, and 2) a zone representing the relatively fractured, altered veins. Various physical characteristics of the two different zones are shown in Table 10. Density = 2650 kg m\(^{-3}\), heat capacity = 1000 J kg\(^{-1}\) K\(^{-1}\), and diffusivity = 10\(^{-9}\) m\(^{2}\) s\(^{-1}\) were used for both zones. The cubic law was used to define the porosity-permeability relationship in both zones (Xu et al., 2004). The model generates changes in porosity and permeability based on changes in mineral abundances.

**Mineralogical Conditions**

The host rock type chosen for the preliminary injection simulations was biotite granodiorite. This rock type dominates the deepest intervals of wells on the 34-9 pad. Granodiorite was also identified as a major rock type in the zone targeted for stimulation in well 46A-19RD. This is an intermediate rock type in terms of composition and alteration found in the East Flank wells. Estimates of the mineralogical composition of the granodiorite (in terms of volume percentage of solid rock) were made on the basis of x-ray diffraction data and petrographic observations (Kovac et al., 2005; Lutz and Moore, 1997). Mineralogically, the granodiorite consists of mostly quartz, plagioclase, and potassium feldspar with minor biotite (Table 11). In general, the granodiorite displays only weak alteration consisting of illitic clays and chlorite (Table 11).

Estimation of the fractured vein mineralogy was made using a more holistic approach based upon the average paragenetic sequence observed in the East Flank wells. Estimates of mineralogical composition in terms of volume percentage of solid rock were based on detailed petrographic observations and petrologic analysis of core and cuttings (Table 11; Kovac et al., 2005; Lutz and Moore, 1997). Porosity and permeability were assumed to be much greater in the fractured vein zone than in the granodiorite zone (Table 10). Initial rock temperature for both zones was 275°C in the preliminary simulations. Conductive heat exchange with the surrounding low-permeability rock is an important process, and is treated with a semi-analytical technique developed by Vinsome and Westerveld (1980).

**Mineral Kinetic Rates and Parameters**

Mineral dissolution and precipitation are considered under kinetic constraints. A general kinetic rate expression is used in TOUGHREACT (Xu et al., 2004):

\[
 r_m = \pm k_m A_m a_{H^+}^n \left(1 - \frac{Q_m}{K_m}\right) \quad (1)
\]

where \(m\) is the mineral index, \(r_m\) is the dissolution/precipitation rate, (positive for dissolution, negative for precipitation), \(k_m\) is the rate constant (moles per unit mineral surface area and unit time) which is temperature-dependent, \(A_m\) is the specific reactive surface area per kg of H\(_2\)O, \(a_{H^+}\) is the activity of H\(^+\), and \(n\) is an empirical reaction order accounting for catalysis by H\(^+\) in solution. \(K_m\) is the equilibrium constant for the mineral-water reaction written for the destruction...
of one mole of mineral m, Q_m is the ion activity product. The temperature dependence of the reaction rate constant can be expressed as:

\[ k = k_{25} \exp \left[ -\frac{E_a}{R (1/T - 1/298.15)} \right] \quad (2) \]

where \( E_a \) is the activation energy, \( k_{25} \) is the rate constant at 25°C, \( R \) is the universal gas constant, and \( T \) is absolute temperature. Table 12 shows the parameters used in the kinetic rate expression.

Table 10. Hydrologic and thermal parameters for the two zones.

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Fractured Vein</th>
<th>Weakly-Altered Granodiorite</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volume (m³)</td>
<td>0.1</td>
<td>0.9</td>
</tr>
<tr>
<td>Permeability (m²)</td>
<td>2.0E-12</td>
<td>2.0E-18</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.10</td>
<td>0.02</td>
</tr>
<tr>
<td>Thermal Conductivity (W* m⁻¹K⁻¹)</td>
<td>2.9</td>
<td>3.0</td>
</tr>
<tr>
<td>Tortuosity</td>
<td>0.3</td>
<td>0.1</td>
</tr>
</tbody>
</table>

Table 11. Simplified initial mineralogical composition of the two zones used in the preliminary simulations.

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Volume Percentage of Solid Rock</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Fractured Vein</td>
</tr>
<tr>
<td>Quartz</td>
<td>0.17</td>
</tr>
<tr>
<td>Potassium Feldspar</td>
<td></td>
</tr>
<tr>
<td>Chlorite</td>
<td>0.23</td>
</tr>
<tr>
<td>Illite</td>
<td>0.08</td>
</tr>
<tr>
<td>Smectite-Na</td>
<td>0.02</td>
</tr>
<tr>
<td>Smectite-Ca</td>
<td>0.06</td>
</tr>
<tr>
<td>Calcite</td>
<td>0.31</td>
</tr>
<tr>
<td>Anorthite</td>
<td></td>
</tr>
<tr>
<td>Annite</td>
<td></td>
</tr>
</tbody>
</table>

Water Chemistry
The composition of the reservoir fluid was estimated based on the approximate composition taken from an East Flank well (Table 13). Initial fluid compositions within the fractured vein and granodiorite zones were calculated by equilibrating the reservoir fluid composition with each
zone’s mineralogical composition at 275°C. An example injection fluid composition that is relatively high in concentrations of Na⁺, Cl⁻, and SiO$_2$(aq) was chosen as the trial injection water (Table 13). The injectate composition was not allowed to change over time.

Table 12. List of kinetic rate parameters used in Eqs. (1) and (2) for minerals considered in the present paper (Xu and Pruess, 2004; Palandri and Kharaka 2004). The first line indicates dissolution parameters and the second line precipitation parameters; the same values were used for both where only one line is shown.

<table>
<thead>
<tr>
<th>Mineral</th>
<th>$k_{25}$ (moles m$^{-2}$ s$^{-1}$)</th>
<th>$E_a$ (KJ/mole)</th>
<th>n (rxn. order)</th>
<th>Surface Area (cm$^2$/g)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calcite</td>
<td>6.918E-2 6.456E-7</td>
<td>18.98 62.76</td>
<td>1 0</td>
<td>9.8 9.8</td>
</tr>
<tr>
<td>Quartz</td>
<td>1.26E-14</td>
<td>87.5</td>
<td>0</td>
<td>9.8</td>
</tr>
<tr>
<td>Am. Silica</td>
<td>7.32E-13 3.80E-10</td>
<td>60.9 49.8</td>
<td>0 0</td>
<td>1.0E6 1.0E6</td>
</tr>
<tr>
<td>K-feldspat</td>
<td>1.00E-12</td>
<td>57.78</td>
<td>0</td>
<td>9.8</td>
</tr>
<tr>
<td>Anorthite</td>
<td>1.00E-12</td>
<td>57.78</td>
<td>0</td>
<td>9.8</td>
</tr>
<tr>
<td>Na-smectite</td>
<td>1.00E-14</td>
<td>58.62</td>
<td>0</td>
<td>151.63</td>
</tr>
<tr>
<td>Ca-smectite</td>
<td>1.00E-14</td>
<td>58.62</td>
<td>0</td>
<td>151.63</td>
</tr>
<tr>
<td>Illite</td>
<td>1.00E-14</td>
<td>58.62</td>
<td>0</td>
<td>151.63</td>
</tr>
<tr>
<td>Annite</td>
<td>2.51E-15 2.51E-15</td>
<td>66.20 66.20</td>
<td>1 0</td>
<td>9.8 9.8</td>
</tr>
<tr>
<td>Dolomite</td>
<td>1.023E-3 4.47E-10</td>
<td>20.90 62.76</td>
<td>1 0</td>
<td>9.8 9.8</td>
</tr>
<tr>
<td>Chlorite</td>
<td>2.51E-12</td>
<td>62.76</td>
<td>0</td>
<td>151.63</td>
</tr>
<tr>
<td>Anhydrite</td>
<td>6.45E-4</td>
<td>14.3</td>
<td>0</td>
<td>9.8</td>
</tr>
</tbody>
</table>

Table 13. Example approximate composition of reservoir fluid from an East Flank well and injection fluid composition as used in the simulations.

<table>
<thead>
<tr>
<th>Chemical Component</th>
<th>Reservoir Fluid Mol/kg</th>
<th>Injection Fluid Mol/kg</th>
</tr>
</thead>
<tbody>
<tr>
<td>SiO$_2$</td>
<td>0.013</td>
<td>0.017</td>
</tr>
<tr>
<td>B(OH)$_3$</td>
<td>8.42E-3</td>
<td>8.42E-3</td>
</tr>
<tr>
<td>Na⁺</td>
<td>0.095</td>
<td>0.12</td>
</tr>
<tr>
<td>K⁺</td>
<td>0.012</td>
<td>0.017</td>
</tr>
<tr>
<td>Li⁺</td>
<td>2.45E-3</td>
<td>5.55E-3</td>
</tr>
<tr>
<td>Ca²⁺</td>
<td>9.55E-4</td>
<td>1.05E-3</td>
</tr>
<tr>
<td>Mg²⁺</td>
<td>4.12E-6</td>
<td></td>
</tr>
<tr>
<td>Sr²⁺</td>
<td>3.6E-5</td>
<td></td>
</tr>
<tr>
<td>Cl⁻</td>
<td>0.11</td>
<td>0.14</td>
</tr>
<tr>
<td>F⁻</td>
<td>1.47E-4</td>
<td>1.36E-4</td>
</tr>
</tbody>
</table>

173
<table>
<thead>
<tr>
<th></th>
<th>1.1E-3</th>
<th>1.25E-4</th>
</tr>
</thead>
<tbody>
<tr>
<td>HCO₃⁻</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SO₄²⁻</td>
<td>3.12E-4</td>
<td>7.06E-4</td>
</tr>
<tr>
<td>HS⁻</td>
<td>3.02E-5</td>
<td></td>
</tr>
<tr>
<td>CH₄</td>
<td>6.25E-10</td>
<td></td>
</tr>
<tr>
<td>pH</td>
<td>6.84</td>
<td>4.87</td>
</tr>
<tr>
<td>T (°C)</td>
<td>275</td>
<td>77</td>
</tr>
</tbody>
</table>

Results

A one-dimensional MINC (multiple interacting continua) model was used. Our conceptual model considers a one-dimensional flow tube between the injection and production wells, which is a small sub-volume of the more extensive three-dimensional reservoir. The initial reservoir conditions were 275°C temperature and 30MPa pressure. An over-pressure of 2MPa was applied to the injection side. The initial simulation was run for a total time of 10 years. Changes in fluid pH, fracture porosity, fracture permeability, fluid temperature, and changes in mineral abundances were monitored to a distance of 594 m from the injection well. Mineral abundance changes were reported in terms of changes in volume fraction for the following minerals: quartz, potassium feldspar, chlorite, illite, sodium smectite, calcium smectite, calcite, dolomite, anorthite, biotite, amorphous silica, and anhydrite. Calcite, quartz, and amorphous silica displayed the most significant changes. Changes in porosity were calculated as a function of mineral dissolution and precipitation. Porosity increase indicates that mineral dissolution is dominant, while porosity decreases when precipitation dominates. Changes in permeability are calculated from changes in porosity as described above.

Figure 3.20 plots porosity versus distance from the injection well at times of 1 day - 10 years after start of injection. Figure 3.21 displays amorphous silica precipitation versus distance at times of 1 day - 10 years after initial injection. It is evident that near-wellbore porosity drops 60% shortly after injection (~1 day after injection), due to amorphous silica precipitation. This is in good agreement with field data on amorphous silica precipitation rates (Padilla et al., 2005; Alcober et al., 2005). Figure 3.22 shows that some quartz precipitation occurs, but that this is several orders of magnitude less significant than the amorphous silica precipitation. Also, the quartz precipitation does not occur as soon as the amorphous silica precipitation. These results are corroborated by field observations (McLin et al., 2006) that identified major amorphous silica and trace quartz in fractures post-injection. Calcite displays a small amount of dissolution near the wellbore (0-0.8m) over the 10 year period (Fig. 4); elsewhere, precipitation is dominant. Further out from the wellbore (~100- 600m), porosity is maintained but has decreased approximately 20% after 10 years. Calcite is the mineral largely responsible for this gradual porosity loss. This is corroborated by observations from the field that calcite dominates the veins further away from the injection wellbore (McLin et al., 2006). Temperature, chemical composition, and pH of injection fluid, host rock and fracture mineralogies can all have great impact on the fate of injection. These parameters will be examined more closely through sensitivity studies in future work. At this point, the relatively large amount of SiO₂(aq) in the injection fluid appears to be a factor that could potentially have a significant impact on porosity and permeability.
Figure 3.20. Porosity versus distance in meters (logarithmic scale) for the simulation.

Figure 3.21. Amorphous silica precipitation versus distance from the injection well. Note that the distance shown is 0-2 meters from the injection point.
Figure 3.22. Quartz precipitation versus distance from the injection point. Note that the distance shown is 0-10 meters from the injection point.

Figure 3.23. Calcite precipitation and minor dissolution (negative values) versus distance for 0-100 m from the injection point.

Amorphous silica precipitation kinetics

Both the model and field experience suggest that under the conditions proposed for the hydrofracture experiment and injection, amorphous silica precipitation could be problematic. Amorphous silica is the mineral expected to precipitate most strongly near the injection well and therefore have the greatest impact on near-wellbore porosity and permeability. Several methods have been proposed in the literature to quantify rates of amorphous silica precipitation. Here
calculations are made using the data for Coso that compare these methods to those used by TOUGHREACT. Similar calculations are also made for quartz, although the kinetics are considered to be much more straightforward for quartz than for amorphous silica.

Amorphous silica precipitation kinetics are complicated and considered to be poorly constrained. It can precipitate through two different mechanisms: 1) molecular deposition and 2) colloidal deposition. Molecular deposition occurs when monomeric silica precipitates directly onto a solid silica surface. Colloidal deposition occurs when the solution is oversaturated in silica by a factor of ten or greater. In this case, the silica molecules polymerize and form a colloid that remains suspended in the fluid. After the colloidal particles reach a critical size, they then begin to precipitate.

Weres et al. (1982) developed a method for calculating molecular silica deposition. Their empirical method calculates deposition based on silica concentration, temperature, pH, and salinity. Table 14 shows input parameters from the East Flank used in making all calculations except Weres et al. (1982). Using Weres et al. (1982) graphical method (Figure 3.24 and Equations (9) and (10) in their paper), the rate of amorphous silica deposition was calculated at a pH = 7 to be 2.8E-7 mol*m\(^{-2}\)*sec\(^{-1}\), and at the pH of injection (~5) to be 5.6E-9 mol*m\(^{-2}\)*sec\(^{-1}\). Therefore, under acid conditions, the rate of deposition decreases by two orders of magnitude compared to neutral conditions.

Carroll et al. (1998) investigated amorphous silica precipitation under simple laboratory conditions, which was found to follow the equation:

\[
\text{Rate}_{\text{ppt}} = k_{\text{ppt}} \exp (-E_a/RT) \left(1 - \exp(\Delta G_r/RT)\right) \quad (3)
\]

and more complicated field observations, which followed the relationships

\[
\text{Rate}_{\text{ppt}} = 10^{-10.00\pm0.06} \left(\exp \Delta G_r/RT\right)^{4.4\pm0.3} \quad (4),
\]

or

\[
\text{Rate}_{\text{ppt}} = 10^{-9.29\pm0.03} \left(\Delta G_r/RT\right)^{1.7\pm0.1} \quad (5).
\]

Using the values for Coso yielded rates of 2.6E-11 [Si]m\(^{-2}\)*sec\(^{-1}\) for the laboratory relationship and 3.1E-8 and 8.1E-10 for the field relationships. The field results are larger than the laboratory results. The authors attributed the difference in values to differing controls on laboratory setup versus field conditions. The dominant precipitation mechanism would be elementary reaction control in the laboratory, while in the more complicated field experiments it would be surface defect/nucleation control (Carroll et. al 1998).

Rimstidt and Barnes (1980) use a method based on transition state theory that is consistent with a thermodynamic approach. This approach is largely the one reactive geochemical programs are based upon, including TOUGHREACT. Using the equations of Rimstidt and Barnes a deposition rate of 1.5E-11 mol*m\(^{-2}\)*sec\(^{-1}\) is obtained.
Using the equations employed in TOUGHREACT for amorphous silica precipitation (Xu et al., 2004):

\[ r = kA[\Omega^0 - 1/(\Omega^2)] \]  \hspace{1cm} (6),

where

\[ k = k_25 \exp[-E_a/R^* (1/T - 1/298.15)] \]  \hspace{1cm} (7),

and

\[ \Omega = Q/K \]  \hspace{1cm} (8)

This method yields a rate of 6.5E-7 mol*m^2*sec^-1.

In looking at the summary of all calculations (Table 15), it is apparent that the calculations made by TOUGHREACT compare well in general to field and empirical rates from the literature, and less well to the theoretical models.

Table 14. A table of constants used to calculate rates of amorphous silica precipitation according to different methods from the literature.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>T (K)</td>
<td>349.7</td>
<td>349.7</td>
<td>349.7</td>
</tr>
<tr>
<td>Area (m^2)</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>k_25 (mol m^-2 sec^-1)</td>
<td>1E-1.9</td>
<td>3.80E-10</td>
<td></td>
</tr>
<tr>
<td>E_a (kJ/mol)</td>
<td>61</td>
<td>49.8</td>
<td></td>
</tr>
<tr>
<td>H</td>
<td>1</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>\Theta</td>
<td>4.4</td>
<td>.5276</td>
<td></td>
</tr>
<tr>
<td>log(Q/K)</td>
<td>.5673</td>
<td>.5276</td>
<td></td>
</tr>
<tr>
<td>\Omega</td>
<td>3.72</td>
<td>3.72</td>
<td></td>
</tr>
<tr>
<td>K_{eq} (from Gunnarsson and Arnorsson, 2000)</td>
<td>4.604E-3</td>
<td>4.604E-3</td>
<td></td>
</tr>
<tr>
<td>(A/M)_{kinetic}</td>
<td>10E4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 15. Summary of amorphous silica precipitation rate estimates using the data for Coso and methodology of the authors listed.
Similar calculations were made for quartz, comparing values from the literature to those generated in TOUGHREACT. The kinetics of quartz precipitation are considered to be much more straightforward than those of amorphous silica. Constants for Coso used to make these calculations are shown in Table 16. The method of Rimstidt and Barnes (1980) as described above was used to generate an approximate precipitation rate of quartz of 2.2E-14 mol*m^-2*sec^-1.

Dove (1994) uses a different approach to the problem. Here, the rate equation is based on a surface reaction model that relates changes in modeled surface complexes with quartz reactivity in aqueous solutions (Dove, 1994). According to Dove’s equation the precipitation rate can be found from the relation:

\[
\text{rate} = \exp^{-10.7T} \exp^{-66000/RT} \theta_{SiOH} + \exp^{4.7T} \exp^{-82700/RT} \theta_{SiO_{tot}}. \tag{9}
\]

Using this method, the rate of quartz precipitation is 3.3E-11 mol*m^-2*sec^-1.

The rate expression for quartz in TOUGHREACT is given in Eq. 1. Thus, it follows that the value calculated by TOUGHREACT is very similar to that of Rimstidt and Barnes (Table 17). These two values are significantly different that that of Dove (1994), which seems reasonable considering the approach is quite different.
Table 16. A table of constants used to calculate rates of quartz precipitation according to different methods from the literature.

<table>
<thead>
<tr>
<th></th>
<th>Rimstidt &amp; Barnes (1980)</th>
<th>TOUGHREACT</th>
</tr>
</thead>
<tbody>
<tr>
<td>T (K)</td>
<td>349.7</td>
<td>349.7</td>
</tr>
<tr>
<td>Area (m²)</td>
<td>1</td>
<td>.001</td>
</tr>
<tr>
<td>$k_{25}$ (mol m⁻² sec⁻¹)</td>
<td></td>
<td>1.2589E-14</td>
</tr>
<tr>
<td>$E_a$ (kJ/mol)</td>
<td></td>
<td>87.5</td>
</tr>
<tr>
<td>H</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>$\Theta$</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>log(Q/K)</td>
<td>1.422</td>
<td>1.413155</td>
</tr>
<tr>
<td>$\Omega$</td>
<td></td>
<td>25.9</td>
</tr>
<tr>
<td>$K_{eq}$ (from Gunnarsson and Arnorsson, 2000)</td>
<td>.000644</td>
<td></td>
</tr>
<tr>
<td>(A/M)$_{kinetic}$</td>
<td>10</td>
<td></td>
</tr>
</tbody>
</table>

Table 17. Summary of quartz precipitation rate estimates using the data for Coso and methodology of the authors listed.

<table>
<thead>
<tr>
<th>Source</th>
<th>Quartz precipitation rates (mol m⁻² sec⁻¹)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rimstidt (1980)</td>
<td>2.2E-14</td>
</tr>
<tr>
<td>Dove (1994)</td>
<td>3.3E-11</td>
</tr>
<tr>
<td>TOUGHREACT</td>
<td>6.2E-14</td>
</tr>
</tbody>
</table>

Conclusions

Geologic, petrographic, temperature, and geochemical data collected on the Coso EGS experiment were input into TOUGHREACT, creating an initial model of injection into an East Flank well. This model generally agrees with post-injection observations from the field. Significant amorphous silica, and minor amounts of calcite, quartz, and anhydrite are shown to precipitate while only calcite shows dissolution in the fractures. Amorphous silica could reduce porosity and permeability in the vicinity of the injection well during enhancement, and this is corroborated by the initial model.

Amorphous silica kinetics, although very important to geothermal operations, are considered to be poorly constrained under geothermal conditions. Using the data for Coso, calculations were made from the literature for the rates of amorphous silica and quartz precipitation and these values were compared to those used by TOUGHREACT. In the case of quartz, values calculated
by TOUGHREACT compare well to values calculated by Rimstidt and Barnes (1980), which follows as the TOUGHREACT method is derived from the Rimstidt and Barnes (1980) method. In the case of amorphous silica, the value calculated by TOUGHREACT is quite different than estimates calculated using Rimstidt and Barnes (1980) and other theoretical methods in the literature. However, it compares well to field and empirical rates from the literature.

3.2.4 References


3.3 Numerical Simulation Modeling of Hydraulic Stimulation (Thomas Kohl and Thomas Megel)

3.3.1 Background and Objectives

The objective of the work performed by GEOWATT AG in the Coso EGS project was the modeling of permeability development within reservoir adjacent to the 34-9RD2 borehole. The investigation was conducted with the hydro-mechanical stimulation code HEX-S, which allows for the simulation of the dynamic development of the reservoir permeability as a result of hydraulically driven failure and subsequent aperture change of predefined fractures due to injection.

For the model of the Coso EGS project site the following hydro-mechanical parameters were taken into account for a model run of the 34-9RD2 stimulation using HEX-S:

a) Network of hydraulically active fracture zones
   - Dip, Azi of dip, depth
   - Shear friction angle (31°)
   - Shear dilation angle (3°)
   - 90% reference closure stress (30 x10^6 Pa)
   - Fracture zone density [2 x10^{-3} m^{-1}]
   - Fracture zone radii (500 m)
   - Slip patches radii (40 m)

b) Rock parameters
   - E-modulus (6 x10^{10} Pa)
   - Poissons ratio (0.25)
c) Stress field (linear function with depth)

- \( \text{shmin} (z) \)
- \( \text{SHmax} (z) \)
- \( \text{Sv} (z) \)
- \( \text{Azi of } \text{SHmax} (11^\circ) \)

e) Initial hydraulics

- \( P (z) \)
- Initial permeability: \( 5 \times 10^{-16} \, \text{m}^2 \)
  (defines the initial apertures)

### 3.3.2 Approach

#### 3.3.2.1 Identification of fracture zones

The fracture zones that can be principally become hydraulically active during a stimulation process must be identified. Also the orientation of these potential zones must be known. The following table gives an overview about the approach chosen for the Coso EGS project:

<table>
<thead>
<tr>
<th>Task</th>
<th>Method</th>
</tr>
</thead>
</table>
| 1. Identification of the hydraulic activity | • Extracting the depth range of zones of lost circulation  
  • Extracting depth range of signals (significant deviations in gradient) in temperature logs |
| 2. Identification of the orientation | • Extracting dip + azi of dip from FMS-logs for the depth range of each identified FZ under task 1  
  • Determination of the set of orientations with the highest occurrences |

#### 3.3.2.2 Example of data interpretation: well 38A-9

In the following an example of data interpretation for the identification of fracture zones (FZ) is given. A rough analysis of data of lost circulation during drilling and of temperature gradient deviation has identified 2 fracture zones (5 and 6) that have been subsequently integrated to the HEX-S model:
For the well 38A the fracture zones 5 and 6 have been selected for model integration since orientation data are available. For these two zones the FMS-orientations have been analyzed statistically. The following view shows a screen shot of the analyzing tool of the project database with the analyzing parameters and results for FZ 5:

The code analyses the data and comprises the results in 15° dip intervals, 30° azimuth intervals and 100 m depth intervals.

This has provided the following distribution of orientations for FZ 5 of 38A:

<table>
<thead>
<tr>
<th>FZ #</th>
<th>FZ depth range</th>
<th>Criteria</th>
<th>Orientation available (FMS)?</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1200 – 1300 ft</td>
<td>Lost circulation</td>
<td>No</td>
</tr>
<tr>
<td>2</td>
<td>2150 – 2250 ft</td>
<td>Lost circulation</td>
<td>No</td>
</tr>
<tr>
<td>3</td>
<td>2350 – 2500 ft</td>
<td>Lost circulation</td>
<td>No</td>
</tr>
<tr>
<td>4</td>
<td>3400 – 3600 ft</td>
<td>Lost circulation</td>
<td>No</td>
</tr>
<tr>
<td>5</td>
<td>5400 – 5500 ft</td>
<td>Temp.-Grad. anomaly</td>
<td>Yes</td>
</tr>
<tr>
<td>6</td>
<td>7350 – 7500 ft</td>
<td>Lost circulation</td>
<td>Yes</td>
</tr>
<tr>
<td>7</td>
<td>8000 – 8100 ft</td>
<td>Lost circulation</td>
<td>No</td>
</tr>
<tr>
<td>8</td>
<td>8000 – 8100 ft</td>
<td>Lost circulation</td>
<td>No</td>
</tr>
<tr>
<td>9</td>
<td>8750 – 9000 ft</td>
<td>Lost circulation</td>
<td>No</td>
</tr>
</tbody>
</table>

For the well 38A the fracture zones 5 and 6 have been selected for model integration since orientation data are available. For these two zones the FMS-orientations have been analyzed statistically. The following view shows a screen shot of the analyzing tool of the project database with the analyzing parameters and results for FZ 5:
3.3.2.3 Deterministically integrated fracture zones from well 38A-9

The analyses described under chapter 3 have been carried out also for wells 38B and 38C. The identified fracture zones from pad 38 which have been deterministically integrated into the HEX-S model for the Coso EGS project, can be summarized as follows:

38A-9: 9FZ
38B-9: 8FZ
38C-9: 12 FZ

Figure 3.24: Overview of the orientation of the deterministically integrated fracture zones from pad 38 into the HEX-S model for the Coso EGS project. The 3 wells are indicated with the letters A, B and C.
3.3.2.4 Deterministically integrated fracture zones from well 34-9RD2

Since no FMS-data has been available so far the fracture zones in the depth ranges of lost circulation have been defined to have an orientation corresponding to the values from the 38 pad. Clearly this can only be a first approach. 3 FZs have been defined for the well 34-9RD2 at the depth of 7500-7990 ft where lost circulation occurred:

<table>
<thead>
<tr>
<th>no</th>
<th>Depth [m]</th>
<th>Dip</th>
<th>Azi</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>-2290</td>
<td>66</td>
<td>44</td>
</tr>
<tr>
<td>2</td>
<td>-2291</td>
<td>67</td>
<td>101</td>
</tr>
<tr>
<td>3</td>
<td>-2294</td>
<td>67</td>
<td>78</td>
</tr>
</tbody>
</table>

3.3.2.5 Deterministically integrated fracture zones in HEX-S

The following gives a view to the deterministically integrated fractures zones in the model. Each fracture zone is subdivided into slip patches indicated by a red dot.
3.3.2.6 Definition of stochastic fracture zones

The generation of stochastically oriented and distributed fracture zones in the parts of model volume where no deterministic information are available is based on the set of FZ orientations of the entire 38 pad.
3.3.3 Results

In a preparatory study for future stimulation under Coso field conditions, the HEX-S model was elaborated. Since no measured hydraulic data on transmissivity distribution in the rock are available, the sensitivity of different material parameters of the HEX-S model have to be tested under the specific conditions of the Coso EGS site. The present report describes the sensitivity of the stochastic distribution of the fracture zones.

The geometry of the numerical model is identical to Kohl (2005) with an extension of 10 km horizontally and 2 km vertically. Hydraulic Dirichlet boundary conditions have been placed at the lateral boundaries of the model. This way, flow is forced to either circulate between the injector well 34-9RD2 and the possible producers at the 38 pad (38A, 38B and 38C) or to percolate towards the outer boundaries.
Figure 3.28: View to the fracture zones integrated into the HEX-model. Red are the deterministic fracture zones, blue are the stochastically generated fracture zones.

Figure 3.29: Steady-state (left) and transient (right) pressure distribution due to injection onto 34-9 RD2. The left figure also illustrates the simulated boreholes, with the real directions drawn as thin lines and the assumed vertical geometry drawn as thick lines.
It can be recognized in Figure 3.29 that the pressure distribution becomes strongly anisotropic in subsurface. Pressure is highest at the OH section of 34-9RD2 and reduces towards the outer border (effect of chosen BC). Generally, it can be stated that pressure is radially distributed only around injection borehole, whereas the fracturization of subsurface leads to a complex pattern since pressure envelopes are oriented along fracture zones.

Given the fracture geometry of this first preliminary model, a rather good connection between 34-9RD2 and 34C-9 could be anticipated. However, more model runs with the real fracture distribution along OH section of 34-9RD2 are required.

In the following sensitivity analysis, the distribution of the stochastic fractures has been varied. For most of the 10 different models, the fracture density (0.0002 fractures/m) and mean fracture extension (200m) were kept constant and only the random "seed number" of the stochastic generation process was varied. Each stochastic realization required a mapping of the new fracture zone network onto the finite element grid.

Since no hydraulic data are available, the study had to assume an initial transmissivity of the 34-9RD2 open borehole section. We have been assuming hydraulic parameters linked to other EGS sites, especially from the European EGS site at Soultz-sous-Forêts. Applying these model parameters, steady-state would be generally reached after 20'000 sec.

![Graph](image)

**Figure 3.30:** Calculated downhole pressure difference in the injector 34-9RD2. From a total of 10 stochastic realization 6 p-t curves are shown.

With the exception of one realization (larger fracture extension and higher density) the results indicate that the final pressure and shearing events will not drastically vary. Generally a pressure difference to hydrostatic conditions of <12 MPa is reached. The model has simulated > 2500 microseismic events corresponding to individual split patch failures. In Figure 3.31 only events with a slip displacement >5 mm are shown.
Figure 3.31: Simulated shearing displacements of one stochastic realization in Coso, induced from a massive injection of 50l/s.

The present results indicate the significance of deterministic fractures, since most realization are insensitive to the stochastic distribution in the outer field. However, under specific conditions, these far-field fractures may become dominating, especially when they represent an ideal linkage to far-field faults, that may represent typical drainage systems.

These results represent an important step towards a future characterization of a Coso reservoir. However, each prognosis of the stimulation behavior requires hydraulic test data which must be available prior to stimulation. Hydraulic models need to be calibrated on these data. In any case, the future HEX-S model for the Coso project should include the borehole data from the newly planned stimulation site.

### 3.3.4 References


Mégel T., Kohl T., Rose P., Reservoir Simulation for stimulation Planning at the Coso EGS Project, GRC Transactions, 29, pp 173-176

Kohl T. and Mégel T., 2005, Coupled Hydro-mechanical modelling of the GPK3 reservoir stimulation at the European EGS site Soultz-sous-Forêts, Proc., 30th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 31-February 2, 2005
3.4 Numerical Simulation Modeling of Thermal Stimulation Processes
(Dan Swenson, Shekhar Gosavi, Ashish Bhat)

3.4.1 Background and Objectives

Hydraulic/thermal stimulation has been used on geothermal wells, although not always deliberately. Many operators inject cold water into a well after it is drilled to clean out drilling mud and to measure the injection capacity as a way of predicting productivity. This may also have hydraulically and thermally stimulated some wells. Many wells that were initially unproductive have been used for injection for some period of time. Then, after a shut-in period, they were retested and found to be productive. Hydraulic and thermal stimulation probably contributed to their improvement, but poor control of other variables and a lack of good data limit our ability to quantify the effect of stimulation.

The objective of the Kansas State University team is to provide coupled thermal-hydraulic-mechanical analysis tools that enable quantitative understanding and prediction of thermal effects on flow in the reservoir. These tools will be applied to analysis of thermal stimulation of wells in the reservoir. Using a combination of analysis and testing, the goal is to clearly identify the conditions under which thermal stimulation is significant and to predict the magnitude of the change resulting from such stimulation. This will be accomplished by incorporating a coupled stress capability into the TOUGH2 code (T2STR).

3.4.2 Coupling HOLA Wellbore Simulator with TOUGH2

In the East flank area of Coso Geothermal field some of the wells are relatively impermeable and exhibit a significant drawdown. Characterization of the flow near the wellbore, becomes more important in such settings. Field data for the Coso wells also reveals the presence of two-phase flow and multiple feedzones. This leaves the standard coupled wellbore flow option in TOUGH2 unusable, since it is limited to wells with a single feedzone. So the HOLA wellbore simulator is coupled with TOUGH2 to perform the analysis near the wellbore.

While doing the coupling we encountered quite a few bugs in HOLA code. As was pointed out in the project group meeting at USGS in Feb-05 and also in Supplement to wellbore models GWELL, GWNACL, and HOLA User’s Guide (Hadgu et al, 1992), more careful review of the HOLA code was required. A detailed description of the bug fixes was reported in the previous quarterly reports. They are summarized here. We believe these should help us provide a much more stable and reliable simulation tool.

3.4.2.1 Summary of bug fixes

Fix #1: Momentum Balance and Friction Pressure Drop
The calculation of momentum balance equation in subroutine MOMENTUM and the residual of momentum balance equation in subroutine RESMOM2 needed to be corrected. This bug would not cause a large error for situations involving single phase and wells of uniform cross section, since the momentum flux term becomes very negligible in such cases. But for the situations in
which fluid velocities vary significantly and in case of the two phase flow, this bug would give significantly erroneous calculations.

Fix #2: Flow-rate Calculation in Subroutine VINNA2
In subroutine VINNA2, while calculating the mass flow rate for the last feedzone, an average of reservoir fluid parameters and wellbore fluid parameters was being taken. All possible scenarios were not addressed here. Instead of this we followed a simpler approach as follows. The reservoir fluid properties are used for calculation of flowrate of fluid that is entering into the wellbore using the deliverability equation and the wellbore fluid parameters are used for calculation of phase velocities.

Fix #3: Newton-Raphson Iteration
There was an issue related to providing a reasonable initial guess value for the Newton-Raphson iteration subroutines, IT1..IT4 and ITERATE1..ITERATE4. A linear extrapolation was used here or a new node was added if possible.

Fix #4: Inclined wells
The calculation methodology for the inclined wells needed correction. The calculation of potential energy in the energy balance equation (routine ENERGY) was affected by this.

Fix #5: Energy balance calculation in subroutine FEED2
The wellbore fluid steam mass fraction X was erroneously altered here, introducing a significant error in the simulation of well-bores with multiple feedzones in two-phase flow conditions.

Fix #6: Erroneous Feedzone Location Specified in the Input
A possibility of error in input file, when specifying the feedzone depth location was overlooked while reading the input file and led to erroneous calculations.

Fix #7: Un-initialized Variables
In subroutine VINNA2 a few uninitialized variables were used in calculations, which was obviously dangerous since they carried garbage value.

Fix #8: Phase Change Handling
Subroutines IT2 and IT3 were re-designed to be able to handle the fluid in both, single phase or two-phase condition.

Fix # 9: The Iteration Subroutine ITHEAD
There were many convergence issues in this routine. In certain cases, it would not efficiently search for a solution in all possible manners. ITHEAD was completely revamped in this view.

Fix #10: Miscellaneous fixes
Among other fixes, a few significant enhancements were also suggested. For example, the Orkiszewski correlations, division by zero error, Ambient heat loss calculations, two-phase flow mixture density, calculation of relative permeabilities, additional two-phase multiplier calculation models. A detailed description of above fixes is available in bhat (December 2005).

### 3.4.2.2 Coupled simulator compared with the deliverability model in TOUGH2

In this problem the output of the coupled TOUGH2-HOLA simulator is compared with that obtained by running the TOUGH2 code alone using the well-on-deliverability option. This problem is picked from the problem #5 in TOUGH2 user’s manual (Pruss et al., 1999), which was originally taken after Hadgu et al. (1995). A single well is located at the center of a large radial grid. The reservoir has a thickness of 500 m with an overlying cap-rock 750 m thick.
This problem was first solved with the original HOLA simulator code as described in Bhat et al. (2005) and the resulting temporal evolution of various parameters was compared with that in TOUGH2 user’s guide (Pruess et al., 1999). Since in both the cases the same HOLA simulator code was used, the resulting profiles matched quite as expected. After fixing a few major bugs in the code, a new blend of results was obtained, as shown in Figure 3.32. As can be observed from the figure, the rise in the flowing enthalpy is not as large as suggested with the original HOLA code. The slight rise in the flowing enthalpy is understandable due to the marginal pressure drop at the bottomhole towards the later part of simulation. But one important observation which still holds true is that the coupled reservoir-wellbore system predicts a long-term production at much higher rates than the deliverability model. Such a large discrepancy strongly lays emphasis on the significance of the coupled wellbore flow simulation, especially when reservoir contains production wells involving multiple feedzones and multiphase fluid flow.

![Figure 3.32: Comparative temporal evolution of parameters (new HOLA code)](image)

3.4.2.3 Simulation of fluid flow in a sample well at East Flank

After reviewing and fixing the HOLA simulator code, it was a good idea to test it on a geothermal well at Coso-East Flank. We tested HOLA result against the observed flowing profile of a well. Since flowing profile data for well 38A-9 or well 38C-9 was not available, another producer in east flank, well 51A-16 was selected.

Typically a matching analysis is performed by testing the suitability of various correlations used in the simulator for the given field data. Also a calibration procedure is required which involves
varying various parameters that are required to carry out the simulation but are not measurable by physical means or are not available from the field data. For example when using option 1 of the HOLA simulator for a well with multiple feedzones, it is assumed that the depth, enthalpy and flowrate contribution of each individual feedzone is known. This can at best be inferred from the cumulative wellhead output and whatever PTS (Pressure-Temperature-Spinner) survey measurements those are available while the well is flowing.
Table 18: Input parameters for matching analysis of well 51A-16

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wellhead pressure</td>
<td>9.55e5 Pa ( ≈ 138.5 psi)</td>
</tr>
<tr>
<td>Wellhead enthalpy</td>
<td>2067.5e3 J/Kg ( ≈ 890 BTU/lbm )</td>
</tr>
<tr>
<td>Wellhead flow rate</td>
<td>30.3 Kg/sec ( ≈ 240 kph )</td>
</tr>
<tr>
<td>Total depth</td>
<td>2580 m ( ≈ 8465 ft )</td>
</tr>
<tr>
<td>Thermal conductivity of the rock</td>
<td>1.5 W/m/°C</td>
</tr>
<tr>
<td>Rock density</td>
<td>2700 kg/m3</td>
</tr>
<tr>
<td>Heat capacity of rock</td>
<td>1000.0 J/kg/°C</td>
</tr>
<tr>
<td>Wellbore geometry</td>
<td>radius: 17 cm, depth: 0-875 m</td>
</tr>
<tr>
<td></td>
<td>radius: 12.22 cm, depth: 875-2580 m</td>
</tr>
<tr>
<td>Pipe roughness</td>
<td>4.9E-04 for depth: 0-875 m</td>
</tr>
<tr>
<td></td>
<td>2.8E-04 for depth: 875-2580 m</td>
</tr>
<tr>
<td>Static reservoir temperature profile</td>
<td></td>
</tr>
<tr>
<td>(available from field data of this well at shut-in time)</td>
<td>Depth (m)</td>
</tr>
<tr>
<td>10</td>
<td>33</td>
</tr>
<tr>
<td>610</td>
<td>179</td>
</tr>
<tr>
<td>2530</td>
<td>323</td>
</tr>
<tr>
<td>Number of feedzones</td>
<td>2</td>
</tr>
<tr>
<td>Parameters at secondary feedzone</td>
<td></td>
</tr>
<tr>
<td>depth: 2550 m</td>
<td></td>
</tr>
<tr>
<td>Flow-rate: 24.07 kg/sec</td>
<td></td>
</tr>
<tr>
<td>Fluid enthalpy: 2300 kJ/kg</td>
<td></td>
</tr>
</tbody>
</table>

For this example, PTS surveys were available that gave guidance on the nature of the fluid flow in wellbore, the approximate number of feedzones, their depths (usually in reality instead of an exact depth, there are some undefined permeable zones along the depth) and their relative strength. A representative flowing wellhead condition several weeks after the well started flowing was chosen. A static temperature profile was determined from the well data while it was shut-in. The parameters that were varied to achieve a match were: feedzone locations, feedzone flow-rates and enthalpies; wellbore roughness and wellbore heat conductivity. The observed flowing pressure and temperature profile was compared with the calculated results. Overall, a good match was obtained. The comparison plot is shown in Figure 3.33.
3.4.2.4 Simulation of fluid flow with a coupled TOUGH2-HOLA simulator

After reviewing and fixing the HOLA simulator code, a representative reservoir-wellbore coupled problem using a 3-D model was solved. Following parameters were given as input for HOLA wellbore,

Table 19: Rock properties for Reservoir Model (TOUGH2)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rock type:</td>
<td>Porous Rock</td>
</tr>
<tr>
<td>Rock Density (kg/m³)</td>
<td>2650</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.01</td>
</tr>
<tr>
<td>Permeability (x, y, z) (m²)</td>
<td>6e-15</td>
</tr>
<tr>
<td>Heat Conductivity (W/m C)</td>
<td>2.1</td>
</tr>
<tr>
<td>Specific Heat (J/kg C)</td>
<td>1000.</td>
</tr>
</tbody>
</table>

Table 20: Input parameters for wellbore model (HOLA)
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wellhead pressure</td>
<td>9.55e5 Pa (≈ 138.5 psi)</td>
</tr>
<tr>
<td>Well Depth</td>
<td>1880 m (≈ 6168 ft)</td>
</tr>
<tr>
<td>Number of feedzones</td>
<td>1 (1880.0 m)</td>
</tr>
<tr>
<td>Productivity Index</td>
<td>5.000E-012</td>
</tr>
<tr>
<td>Well geometry</td>
<td>Casing of 13.375” from 0 to 875 m (≈2870 ft), Liner of 9.625” from 875 m (2870 ft) to 2580.0 m (8465 ft)</td>
</tr>
<tr>
<td>Pipe roughness</td>
<td>4.9E-04 for depth: 0-875 m</td>
</tr>
<tr>
<td></td>
<td>2.8E-04 for depth: 875-2580 m</td>
</tr>
</tbody>
</table>

The problem was successfully solved for production for duration of 20 years. A pressure drawdown can be seen in figure below towards the lower right hand part of reservoir. The HOLA feedzone is located there.

![Figure 3.34: Coupled Reservoir-Wellbore Simulation](image)

The same model was also successfully tested in a separate problem for multiple wellbore coupling by specifying other wellbores in the reservoir. Also a comparison of bottomhole flow-rate is shown below with the three options available now to calculate the two-phase multiplier.
For the initial part of the production cycle, the two newly added methods predict smaller flowrates as compared to the original relation. But after about 7 days of production time, all the three methods tend to give similar prediction of flowrate within less than 10% of each other. It has not known yet if this is universally true; further comparative investigation is needed in this case using a wide range of problems. Additionally, it can be noted here that the new methods significantly reduced (8%) the total number of iterations required in HOLA, for the complete simulation run of 20 years.
The one-way, loose-backward, and fully-coupled THM formulations for porous media were developed and implemented. The details of formulation, implementation and verification problems are discussed. The fractured media implementation and demonstration problem details are also discussed.

### 3.4.3.1 Loose backward coupling

We have considered following relations between the mean effective stress and porosity, and permeability.

\[
\phi = \phi_r + (\phi_r - \phi_0) \exp(\alpha \sigma_M)
\]

\[
k = k_0 \exp\left(c \left( \frac{\phi}{\phi_0} - 1 \right) \right)
\]

**Verification of loose backward coupling**

A single column (no gravitational effect considered on the finite element side to simplify the analytical solution) with constant flow along the column is considered for test problem. The bottom pressure is assumed to be fixed and the pressure along the column, modified porosities, permeabilities are compared with solution obtained using Maple.

The effective stress in given conditions is

\[
\sigma_M = \frac{p_z}{3}
\]

where the pressure at any depth is written as

\[
p_z = p_{\text{Bottom}} + dp
\]

The non-linear equation in \(dp\) using the Darcy’s law is obtained as

\[
k_0 \exp\left(c \left( \frac{\phi_r + (\phi_r - \phi_0) \exp\left(\alpha \frac{p_{\text{Bottom}} + dp}{3} \right)}{\phi_0} \right) - 1 \right)
\]

\[
q_z = -\rho \frac{\mu_y}{\mu_y} \left( \frac{dp}{z - \rho g} \right)
\]

This equation is solved for \(dp\) using Maple and the results are compared with the solution obtained from the loosely two way coupled T2STR. The comparison plots are as follows
Figure 3.36. Comparison of Pressures and Permeabilities

Figure 3.37. Comparison of Mean effective stress and porosities
The comparison is very good and confirms the correct implementation of the loosely coupled backward coupling.

A similar analysis was performed with gravity effect included in the stress side. Due to the circular relations, the hand-calculated solution does not include the latest porosities and hence the comparison plots show expected but acceptable deviations.

### 3.4.3.2 Fully coupled implementation

T2STR is developed to implement fully coupled T-H-M problem for EOS1 (water) in TOUGH2. The generalized formulation applicable for single phase as well as two-phase is detailed. Some verification problems used to validate code are also discussed.

#### Generalized formulation

The primary variables in TOUGH2 for two phase situations are gas phase pressure and gas phase saturation. The momentum equations will need to be reformulated to express in those variables.

**Solid phase pressure**

The solid phase pressure can be written as

\[ p_s = p_i S_i + p_g S_g = \sum_{\varphi} p_{\varphi} S_{\varphi} \]

Using capillary pressure, the change in solid phase pressure, in vector form can be written as

\[ \Delta p = \Delta p_g + [C_{g}^{p}] \Delta S_g \]

where \( C_{g}^{p} \) is the diagonal (square) matrix of size equal to number of nodes, given as

\[
\begin{bmatrix}
(1 - S_g) \frac{\partial p_c}{\partial S_g} - p_c \\
\vdots \\
0 \\
\end{bmatrix}
\]

and denominated as phase-coefficient matrix for pressure-saturation.

**Temperature**

The temperature for two phase problem is expressed as function of gas phase pressure and saturation in two phase problems in TOUGH2, i.e.

\[ T = T(p_g, S_g) \]

The change in temperature calculated as

\[ \Delta T = \frac{\partial T}{\partial p_g} \Delta p_g + \frac{\partial T}{\partial S_g} \Delta S_g \]
In vector form
\[ \Delta T = C_{p_s}^T \Delta p_s + C_{S_s}^T \Delta S_s \]

The phase coefficient matrices for temperature-pressure and for temperature-saturation are given as
\[
\begin{bmatrix}
\frac{\partial T}{\partial p_s} |_{p_s=1} & \cdots & 0 \\
0 & \frac{\partial T}{\partial p_s} |_{p_s=numNodes} 
\end{bmatrix}
\]

and
\[
\begin{bmatrix}
\frac{\partial T}{\partial S_s} |_{S_s=1} & \cdots & 0 \\
0 & \frac{\partial T}{\partial S_s} |_{S_s=numNodes} 
\end{bmatrix}
\]

respectively.

Newton-Raphson Formulation

The Newton-Raphson formulation for the FEM equations can be obtained by defining the residual \( R \) as follows
\[ R = g - f(\Delta u, \Delta p, \Delta T) \]

where \( g \) represents forces independent of unknown variables, i.e. pressure, temperature, and displacements, and \( f \) represents the internal forces and the hydrostatic forces. We can define the residual using the FEM formulation discussed before as
\[
R = \left( \int_V \mathbf{N}^T \mathbf{b} \, dV + \int_S \mathbf{N}^T \mathbf{t} \, dS \right) - \left( \int_V \mathbf{B}^T \mathbf{\sigma}'' \, dV - \int_V \mathbf{B}^T \mathbf{mN} \mathbf{p} \, dV \right)
\]

or expanding the modified effective stress terms
\[
R = \left( \int_V \mathbf{N}^T \mathbf{b} \, dV + \int_S \mathbf{N}^T \mathbf{t} \, dS - \left( \int_V \mathbf{B}^T \mathbf{DB} \, dV \right) \Delta \mathbf{u} \right) - \left( \int_V \mathbf{B}^T \mathbf{DB} \, dV \right) \Delta \mathbf{u} - \int_V \mathbf{B}^T \mathbf{mN} \mathbf{N} \, dV

- \left( 3K \alpha_T \right) \int_V \mathbf{B}^T \mathbf{mN} \Delta T \, dV - \left( \int_V \mathbf{B}^T \mathbf{mN} \mathbf{p}_0 \, dV \right) + \int_V \mathbf{B}^T \mathbf{\sigma}''_0 \, dV \]
where first parenthesis represents the independent terms $g$ and second one represents the variable dependent terms $f$. The subscript $a$ for the unknown displacements, ‘$u’s$, is dropped for brevity henceforth. Considering the implementation, $p_0$ and $\sigma''_0$ terms are included in $f$ even if they are not dependent terms. Thus function $f$ can be evaluated from the total stress. Using the vector form for change in pressure and change in temperature as shown above, we can write the residual as

$$
R = \left( \int_v N^T b \, dV + \int_v N^T t \, dS - \int_v B^T D \, dV \Delta u \right)
$$

$$
- \left( \int_v B^T DB \, dV \Delta u - \int_v B^T \alpha mN \left( \Delta p_g + \left[ C^p_{g_a} \right] \Delta S_g \right) dV \right)
$$

$$
- \left( \int_v \left( 3K_\alpha \right) mN C^p_{g_a} \Delta p_g + \alpha mN \Delta S_g \right) dV
$$

$$
- \left( \int_v B^T \alpha mN p_0 \, dV + \int_v B^T \sigma''_0 \, dV \right)
$$

Rearranging

$$
R = \left( \int_v N^T b \, dV + \int_v N^T t \, dS - \int_v B^T D \, dV \Delta u \right)
$$

$$
- \left( \int_v B^T DB \, dV \Delta u \right)
$$

$$
- \int_v B^T \left[ \left( 3K_\alpha \right) mN C^p_{g_a} + \alpha mN \right] \Delta p_g \, dV
$$

$$
- \int_v B^T \left[ \left( 3K_\alpha \right) mN C^p_{g_a} \Delta S_g \right] \Delta S_g \, dV
$$

$$
- \int_v B^T \alpha mN p_0 \, dV + \int_v B^T \sigma''_0 \, dV
$$

Again, here first parenthesis represents $g$ and second represents $f$ such that

$$
R = g - f(\Delta u, \Delta p_g, \Delta S_g)
$$

Now we can write $f$ as
The final Newton-Raphson formulation can be written as
\[ f = \left( \int B^T DB \, dV \right) \Lambda u_a \]
\[ - \left( \int B^T \left[ (3K\alpha_T) mN C_{p_e}^T + \alpha mN \right] dV \right) \Delta p_g \]
\[ - \left( \int B^T \left[ (3K\alpha_T) mN C_{s_i}^T + \alpha mN C_{p_s}^p \right] dV \right) \Delta S_g \]
\[ - \int B^T \alpha mN p_0 \, dV + \int B^T \sigma'' \, dV \]

where the coefficient matrices are as follows,
\[ K_e = \int B^T DB \, dV \],
\[ Q_{p_e} = - \int B^T \left[ (3K\alpha_T) mN C_{p_e}^T + \alpha mN \right] dV \],
and
\[ Q_{s_i} = - \int B^T \left[ (3K\alpha_T) mN C_{s_i}^T + \alpha mN C_{p_s}^p \right] dV \].

Since the phase-coefficient matrices are constant with respect to the element properties, we can rewrite the coefficient matrices as
\[ Q_{p_e} = - \int B^T \left( 3K\alpha_T \right) mN dV C_{p_e}^T - \int B^T \alpha mN dV \]
and
\[ Q_{s_i} = - \int B^T \left( 3K\alpha_T \right) mN dV C_{s_i}^T - \int B^T \alpha mN dV C_{p_s}^p \].
Using the notations applied in single phase for the coefficient matrices it can be written as

\[ Q_{p_e} = -Q_T C_{p_e}^T - Q_p \]

and

\[ Q_{S_g} = -Q_T C_{S_g}^T - Q_p C_{S_p}^p \]

Generalization for multiphase analysis (Variable switching)

As can be seen easily, the single phase formulation can be formulated as a special case of the above two equations. In single phase, the independent variables are pressure and temperature hence the phase-coefficient matrices, \( C_{p_e}^T \) and \( C_{S_p}^p \) (now \( C_{T}^p \)), will be zero. In single phase the variables are pressure and temperature, hence the coefficient \( C_{S_g}^T \) will be the phase coefficient matrix between temperatures and hence unity, leading to the single phase relations.

The general formulation, applicable for single phase or two phase condition, can be written as

\[
\begin{align*}
\left( K_e \right)^{(i-1)} \Delta \mathbf{u}_u^{(i)} + \left( Q_{V_1} \right)^{(i-1)} \Delta \mathbf{V}_1^{(i)} + \left( Q_{V_2} \right)^{(i-1)} \Delta \mathbf{V}_2^{(i)} & = \int_V \mathbf{N}_T^T \mathbf{b} \ dV + \int_S \mathbf{N}_T^T \mathbf{t} \ dS - \int_V \left( \mathbf{B}^T \mathbf{D} \mathbf{B}^T \right) \mathbf{u}_m \ dV \\
& \quad - \int_V \left( \mathbf{B}^T \mathbf{B} \mathbf{N} \mathbf{p}_0 \right) \ dV + \int_V \mathbf{B}^T \mathbf{F}_0 \ dV
\end{align*}
\]

where \( \mathbf{V}_1 \) and \( \mathbf{V}_2 \) represent the primary variables corresponding to the phase condition.

The fully coupled model is implemented as another option. Thus a user would be able to carry out one way coupled, loose one-way coupled, or a fully coupled analysis with or without porosity/permeability modification. The T2STR record is used to select one of these options.

### 3.4.3.3 Verification of fully coupled implementation

A well test analysis was carried out and compared with the analytical solution. The T2STR code was tested using additional benchmark problems. A problem based on the paper of Aboustit et. al (1982), used by Lewis and Schrefler (1998), is used to verify the complete THM formulation.

A two phase problem is solved with certain gas saturation to show basic correctness of set-up for two phase analysis. Then, a two phase THM problem is solved to demonstrate the capability of the T2STR code. Since the analytical solution does not exist, the simulation results are analysed using the understanding the physics of the problem.
Well test analysis

The analytic solution for an infinite reservoir derived by Horner (1967) is given below. The analytic solution is used to check the implementation in T2STR.

Analytic Solution

The governing equation of flow by Horner (1967) is given as

\[
\frac{\partial^2 p}{\partial r^2} + \frac{1}{r} \frac{\partial p}{\partial r} = \left( \frac{c_i \phi \mu}{k} \right) \frac{\partial p}{\partial t}
\]

The analytic solution for the case of a well at the center of an infinite circular reservoir is then given as:

\[
p = p_0 + \frac{q \mu}{4\pi kh} \left\{ Ei \left( -\frac{r^2 \phi \mu c_i}{4kt} \right) \right\}
\]

where, \( Ei \) is the exponential integral function, \( c_i \) is the total compressibility.

Simulation

A T2STR model, with parameters specified in Table 21, was used to simulate the infinite reservoir model. The reservoir boundary was assumed to be at 700 m and hence the far-field effects are negligible prompting the comparison with the infinite reservoir model. A quarter model of the reservoir was modeled using the symmetry conditions. The corner well cells were of the size, 0.025m, obtained approximately equivalent to same cross sectional area using the well radius of 0.035m. The height of TOUGH2 model was 13.65 m. The flow rate condition was specified at the well cells.

Table 21. Simulation Parameters (Well Test Analysis).

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial reservoir pressure, ( p_0 )</td>
<td>530 KPa</td>
</tr>
<tr>
<td>Constant Flow rate, ( q_1 )</td>
<td>3.5e-2 kg/s</td>
</tr>
<tr>
<td>Viscosity, ( \mu )</td>
<td>0.00105 Ns/m^2</td>
</tr>
<tr>
<td>Formation thickness(withdrawal height), ( h )</td>
<td>13.65 m</td>
</tr>
<tr>
<td>Porosity, ( \phi )</td>
<td>0.05</td>
</tr>
<tr>
<td>Well radius, ( r_w )</td>
<td>0.035 m</td>
</tr>
<tr>
<td>Radius of the boundary, ( r_b )</td>
<td>700 m</td>
</tr>
<tr>
<td>Young’s Modulus, ( E )</td>
<td>1e9 Pa</td>
</tr>
<tr>
<td>Poisson’s ratio, ( \nu )</td>
<td>0.1</td>
</tr>
<tr>
<td>Biot-Willis Coefficient, ( \alpha )</td>
<td>0.7091</td>
</tr>
</tbody>
</table>
The total compressibility, \( c_t \), is the combined compressibility of the solid and fluid. The value used in the analytic solution is 4.83e-10 \( 1/\text{Pa} \). The fluid compressibility is calculated by TOUGH2 as function of pressure and temperature. Since the temperature is constant, the variation in fluid compressibility is negligible and we can assume it to be constant. The solid compressibility in T2STR is decided through the Biot-Willis coefficient, \( \alpha \). The reservoir model in the analysis is subjected to boundary conditions of roller support on all sides. Hence the volumetric strain is going to be zero. The governing equation of fluid flow then becomes

\[
\left[ \phi \frac{\partial (\rho_w)}{\partial t} + \nabla \cdot \mathbf{q}_w \right] + \left[ \rho_w \left( \frac{\alpha - \phi}{K_s} \frac{\partial p_w}{\partial t} \right) \right] = 0
\]

Using Darcy’s Law and comparing the coefficients of the term with pressure variation with time, we can find the relation between compressibilities as follows

\[
c_t = \frac{\phi}{K_f} + \frac{(\alpha - \phi)}{K_S}
\]

where the relation between Biot-Willis coefficient and the solid (grain) bulk modulus is given as

\[
\alpha = 1 - \frac{K}{K_S}
\]

We obtain the Biot-Willis coefficient by solving for compressibility.

Results and Conclusion
The comparison of the analytical solution and the simulation results using T2STR are shown in Figure 3.38. As seen there is very good comparison between the pressures at the well. The negligible variation can be attributed to the varying viscosity (the variation is also negligible) in T2STR with pressure and assumption of constant viscosity in the analytical model.

![Figure 3.38. Comparison of pressures at the well during withdrawal test.](image-url)
The well test analysis confirms the accuracy of implementation of the effects of the solid grain compressibility in the fluid flow equation.

One Dimensional Thermo-elastic Consolidation (THM) Problem

Aboustit et al. (1982, 1985) have given the coupled finite element formulation of quasi-static, linear thermoelastic consolidation assuming infinitesimal strain. Lewis and Schrefler (1998) have solved the same problem studying the isothermal consolidation, thermo-elastic deformation, and non-isothermal consolidation as well. Gatmiri and DeLage (1997) also have studied the problem using a new concept of thermal void ratio state surface. An analysis, similar to that of Lewis and Schrefler (1998), is carried out using T2STR. There is some inconsistency in the problem data sets and the parameters in the papers. Since the T2STR consolidation (Hydro-mechanical) code has already been verified using Terzaghi’s and Gibson’s 2D problems, the hydro-mechanical model was used to set the common ground for comparisons of the complete thermo-hydro-mechanical problem.

Figure 3.39. One dimensional model of thermo-elastic consolidation problem.

The problem consists of a column subjected to surface load $F_0$ and a constant surface temperature $T$, differing by $\Delta T$ from the reservoir initial temperature of $T_0$. The fluid and solid are considered incompressible and the thermal expansion of fluid is neglected. In the heat transfer problem the convective heat transfer is also neglected by Lewis & Schrefler (1998). The variation in viscosity with temperature and pressure is neglected in the problem, as well. The top surface is permeable and the sides and bottom are supported on rollers. The analysis is done in three steps, initially only the isothermal consolidation is compared, then only surface temperature
is applied and the deformation due to only thermal effects are studied and finally a couple thermo-hydro-mechanical problem i.e. non-isothermal consolidation problem is solved.

Governing Equations
Considering the above assumptions, the equation of conservation of mass reduces to

\[
\left( \phi \frac{\partial (S_{\psi} \rho_{\psi}^e)}{\partial t} + \nabla \cdot \mathbf{q}_{\psi} \right) + S_{\psi} \rho_{\psi} \frac{\partial e_{\psi}}{\partial t} = 0
\]

where the terms due to solid and fluid compressibility are neglected and no external source is present.

In the case of non-isothermal analysis, the conservation of energy equation is given as

\[
\frac{\partial \left( \phi \sum S_{\psi} \rho_{\psi}^E u_{\psi}^E + (1-\phi) \rho_{s} u_{s}^E \right)}{\partial t} = -\nabla \cdot \left( \sum \mathbf{q}_{\psi} h_{\psi} \right) - \nabla \cdot \mathbf{J}_C^H
\]

where

\[
\mathbf{J}_C^H = \sum_{\psi} \mathbf{J}_{C_{\psi}}^H + \mathbf{J}_s^H = \left( \phi \sum \lambda_{\psi} + (1-\phi) \lambda_s \right) \Delta T
\]

The \( \lambda \) s represent the thermal conductivities of the solid and fluids. Neglecting the convective heat transfer term and considering heat transfer only in one dimension, the energy equation becomes

\[
\frac{\partial \left( \phi \sum S_{\psi} \rho_{\psi}^E u_{\psi}^E + (1-\phi) \rho_{s} u_{s}^E \right)}{\partial t} = -\left( \phi \sum \lambda_{\psi} + (1-\phi) \lambda_s \right) \frac{\partial T}{\partial z}
\]

where, the thermal conductivities have been assumed constant with respect to time.

TOUGH2 calculates the internal energy term of fluid using the enthalpy relation

\[
u = h - \frac{p}{\rho}
\]

such that

\[
\frac{\partial \left( \phi \sum S_{\psi} \rho_{\psi} \left( \frac{h_{\psi}}{\rho_{\psi}} - \frac{p_{\psi}}{\rho_{\psi}} \right) + (1-\phi) \rho_{s} c_s \Delta T \right)}{\partial t} = -\left( \phi \sum \lambda_{\psi} + (1-\phi) \lambda_s \right) \frac{\partial T}{\partial z}
\]

and Lewis et. al express the internal energy using the specific heat capacity as

\[
\frac{\partial \left( \phi \sum S_{\psi} \rho_{\psi}^E c_{\psi} + (1-\phi) \rho_{s} c_s \Delta T \right)}{\partial t} = -\left( \phi \sum \lambda_{\psi} + (1-\phi) \lambda_s \right) \frac{\partial T}{\partial z}
\]

or using the average heat capacity can be written as
\[
\frac{\partial (\rho c) \Delta T}{\partial t} = -\left(\lambda\right) \frac{\partial T}{\partial z}
\]

In the implementation using T2STR, to match the average heat capacity and avoid its variation with temperature and pressure, the fluid internal energy term is zeroed and equivalent constant value is added to obtain the correct average heat capacity.

Simulation
The parameters required for the simulation were obtained from the relevant references. The values and/or units of most of the parameters are inconsistent in all of the references. Hence the parameter value selection (out of different sets projecting through the references) was done using the simulation results. The parameters used were as listed in Table 22.
While determining the simulation parameters, the already established hydro-mechanical coupling was taken as reference and comparing the results for it, some parameter values were confirmed.

Results and Comparison
The results were compared with the plots given by Lewis et. al (1998) and are shown in Figure 3.40. The slight variations in the plots can be attributed to not properly defined parameter values, assumptions regarding constant parameters (values not available) and differences in the implementation. This verifies the accuracy of the coupled thermo-hydro-mechanical T2STR code.
Table 22. Simulation Parameters (THM Single Phase Problem).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Size</td>
<td>2m x 2m x 7m</td>
</tr>
<tr>
<td>Mesh</td>
<td>3 x 3 x 49</td>
</tr>
<tr>
<td>Young’s Modulus, $E$</td>
<td>5.886e7 Pa</td>
</tr>
<tr>
<td>Poisson’s ratio, $\nu$</td>
<td>0.4</td>
</tr>
<tr>
<td>Permeability, $k$</td>
<td>7.3e-13 m$^2$</td>
</tr>
<tr>
<td>Avg. Thermal Conductivity, $\lambda$</td>
<td>836.8 W/mC</td>
</tr>
<tr>
<td>Avg. heat capacity, $(\rho c)_a$</td>
<td>40 kCal/ m°C</td>
</tr>
<tr>
<td>Specific Heat (derived from heat cap.), $c$</td>
<td>104.67 J/ kg C</td>
</tr>
<tr>
<td>Thermal Expansion Coefficient, $\alpha_T$</td>
<td>0.3e-6 1/C</td>
</tr>
<tr>
<td>Biot-Willis Coefficient, $\alpha$</td>
<td>1.0</td>
</tr>
<tr>
<td>Density of rock, $\rho_s$</td>
<td>2200 kg /m$^3$</td>
</tr>
<tr>
<td>Density of water, $\rho_w$</td>
<td>1000 kg/m$^3$</td>
</tr>
<tr>
<td>External Load, $F_0$</td>
<td>1e4 Pa</td>
</tr>
<tr>
<td>Initial reservoir pressure, $p_0$</td>
<td>1e5 Pa</td>
</tr>
<tr>
<td>Initial reservoir temperature, $T_0$</td>
<td>5 C</td>
</tr>
<tr>
<td>Applied surface temperature, $T_s$</td>
<td>55 C</td>
</tr>
</tbody>
</table>

Figure 3.40. Comparison of displacements at the top.
Two Phase Thermo-elastic Consolidation Problem

The same 1D thermo-elastic consolidation problem was solved with two phase condition. Lewis and Schrefler have done it for lower temperature and taking into account the air as a third phase.

![Figure 3.41. One dimensional model of thermo-elastic consolidation problem (Two-phase).](image)

We have only EOS1 connected to T2STR and hence the problem was done only for two phase analysis. But the temperature was kept high enough to see the phase change effects prominently in the simulation.

The problem consists of a column subjected to surface load $F_0$ and a constant surface temperature $T$, differing by $\Delta T$ from the reservoir initial temperature of $T_0$. The fluid is considered compressible but the solid is incompressible. The variation in viscosity with temperature and pressure is not neglected in this problem. The top surface is permeable and the sides and bottom are supported on rollers. The analysis is done as a thermo-hydro-mechanical problem i.e. non-isothermal consolidation problem is solved.

Governing Equations

The governing equations are same as stated in single phase problem since it is general formulation. In the implementation using T2STR, no changes were made in TOUGH2 code and hence the analysis carried out is general.

Simulation

The parameters required for the simulation was mostly similar to the single-phase consolidation problem. The initial conditions were changed to demonstrate the implementation for a two phase problem. The parameters used were as listed in Table 23.
Results and Comparison
There is no analytical solution available for this problem and hence the results are shown and are
discussed with the physical understanding of the problem.
The variation in pressure, temperature and saturation is seen in Figure 3.42, Figure 3.43, and
Figure 3.44 at time 10, 1e4 and 1e7 seconds respectively. The displacement plots under different
simulation runs are also shown in Figure 3.45.

As is evident, since there is small amount of gas, initially the load is taken by the solid and hence
we see the downward displacement corresponding to the load. This displacement can be easily
calculated using the simple elasticity calculations and is verified. In the case of a single phase
isothermal problem, the load would shift to the liquid and the pressure would increase. But since
there is highly compressible gas existing in the reservoir, we should not expect significant rise in
pressure. However, this problem includes heating at the top of the reservoir. This causes
vaporization and increased pressure in the heated cells. Due to the relatively low permeability of
the reservoir, the drainage is not rapid.

As the pressure increases in the reservoir with increase in temperature, the reservoir expands and
we see positive displacement at the surface. As seen from the displacement plots, Figure 3.45,
major part of the expansion of the reservoir is due to the increase in pressure and the thermal
expansion contributes to a smaller part. In the later times, the reservoir is full of gas and it starts
draining through the surface. Thus we can see the pressure dropping rapidly.

Eventually pressure reaches the atmospheric pressure value of 1e5 Pa with temperature of 150°C
and the column is fully saturated with gas. Due to the drop in pressure the surface falls down and
the final displacement of the surface is, as expected, equal to the resultant of the displacements
due to the thermal expansion of the column and due to the external load applied.
Table 23. Simulation Parameters (Two Phase).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Size</td>
<td>2m x 2m x 7m</td>
</tr>
<tr>
<td>Mesh</td>
<td>3 x 3 x 49</td>
</tr>
<tr>
<td>Young’s Modulus, E</td>
<td>5.886e7 Pa</td>
</tr>
<tr>
<td>Poisson’s ratio, ν</td>
<td>0.4</td>
</tr>
<tr>
<td>Permeability, k</td>
<td>7.3e-13 m²</td>
</tr>
<tr>
<td>Avg. Thermal Conductivity, λ</td>
<td>836.8 W/m°C</td>
</tr>
<tr>
<td>Specific Heat (derived from heat cap.), c</td>
<td>100 J/kg°C</td>
</tr>
<tr>
<td>Thermal Expansion Coefficient, αₜ</td>
<td>0.31e-6 1/C</td>
</tr>
<tr>
<td>Biot-Willis Coefficient, α</td>
<td>1.0</td>
</tr>
<tr>
<td>Density of rock, ρₛ</td>
<td>2200 kg/m³</td>
</tr>
<tr>
<td>Density of water, ρₜ</td>
<td>1000 kg/m³</td>
</tr>
<tr>
<td>External Load, F₀</td>
<td>1e4 Pa</td>
</tr>
<tr>
<td>Initial reservoir pressure, p₀</td>
<td>1e5 Pa</td>
</tr>
<tr>
<td>Initial gas saturation, Sₙ</td>
<td>0.08</td>
</tr>
<tr>
<td>Applied surface temperature, Tₛ</td>
<td>150°C</td>
</tr>
<tr>
<td>Initial reservoir temperature, T₀</td>
<td>99.6°C</td>
</tr>
</tbody>
</table>

(corresponding to given p₀ and Sₙ)

Figure 3.42. Comparison of pressures and deformation of the column.
Figure 3.43. Comparison of temperature and deformation of the column.

Figure 3.44. Comparison of saturation of gas in the column.

In the displacement plots, Figure 3.45, the simulations other than the complete THM is carried out using one way coupling. This helps to see the individual effects of pressure and temperature on the column.

The “Hydro-Mech” legend plot indicates the one way coupling simulation under isothermal conditions. Hence it shows the deformation mainly due to the externally applied load only, since there is negligible pressure change in the column as the small quantity of the compressible gas is already present in the column.

The “Thermo-Mech” legend displacement plot shows the combined effect of the externally applied load and only the thermal effects. This was achieved by turning off the poroelastic effects using the respective flag in the T2STR record in the TOUGH2 input file.
The “Hydro-Mech (T)” legend indicates the simulation, where in, TOUGH2 run was done using non-isothermal conditions, thus capturing the pressure variation due to the phase changes and increase in pressure due to undrained condition as explained above. But the thermal effects on displacement were neglected by setting the flag in T2STR record of the TOUGH2 input file to zero. Hence in “Hydro-Mech (T)” legend displacement plot, we see the final deformation exactly equal to the initial deformation, which is solely due to externally applied load.

Figure 3.46. Pressure and Temperature comparisons at 2500 and 3000 secs.
In the “THM” simulation, there is a clear jump in the displacements between time 2500 sec to 3000 sec and later at time 1.4e6 seconds. Consider Figure 3.46 and Figure 3.47, which show the comparison of pressure, temperature and saturation comparisons between the two time steps. Note that the saturation legend is between 0.1 and 0.0.

As the phase change from liquid to gas due to heating from the top of the column happens, the phase change travels from the top of the reservoir to the bottom. Since we have not included gravity in the analysis, presence of gas below the liquid phase can be explained in line with the initial conditions. Also the movement of the fluid phases is controlled by the extent of the heating due to conduction from the top to the bottom in the reservoir. The transitional phase-line, i.e. the depth at which the phase change is occurring at the instance in time, moves down as the heating progresses. As the transitional phase-line moves, the location of the maximum pressure in the column moves with it. The top of the column is fixed at lower pressure and the bottom of the reservoir is at lower pressure due to gaseous phase and absence of gravitational load. With the fluid movement to equilibrate the pressure in the column inducing the increase in pressure in the bottom of the transitional phase-line, the phase change from gas to fluid occurs. Due to phase change then, there is sudden change in the pressure resulting in the sudden jump in displacement.

![Saturation comparison at t = 2500 and 3000 seconds.](image)

*Figure 3.47. Saturation comparison at t = 2500 and 3000 seconds.*

In the later part of the simulation, due to heating there is complete phase change from liquid to gas, which also is accompanied by the drainage from the top resulting in sudden pressure drop inducing the compaction of the column.

### 3.4.3.4 Modeling of fractured rock mass
The fractures in T2STR are implemented as discrete fractures using joint elements. These joint elements exhibit the fracture interaction with continuum elements. The fracture behavior expresses the effects of surface traction due to joint contact stress (the non-linear relationship between the joint opening and the joint stresses) and the forces due to pressure differential in the fluid pressure between the fracture and adjacent rock element.

In T2STR, the mesh is restricted to a Cartesian mesh and hence the global and local coordinate system orientation is same for any element. In the TOUGH2 (fluid flow, IFDM) mesh the fracture is represented by two sets of rows. In the finite element mesh it would be represented by a single row of the joint elements. The idea of the mesh structure is represented in Figure 3.48.

Fracture Behavior

The finite element formulation for the fracture behavior is derived as follows. The fracture element is a volume element with the surface tractions and pressures acting on the faces of the fracture. Consider a single element with the node numbering as shown in Figure 3.49.
Figure 3.49. Node numbering and representative forces in fracture behavior.

The force balance for the element due to surface traction $t^e$ from the contact, the fluid pressure $p^e$, and external forces $F_{ext}$ is given as

$$\mathbf{F}_{ext} - \int_V \mathbf{B}^T \sigma dV = 0$$

where $\sigma$ is used for representing the stresses due to combined effect of contact stresses and fluid pressure as follows

$$\sigma = t^e + p^e$$

The pressure forces due $p^e$ to are given by

$$\mathbf{F}_p^e = \left( \int_V \mathbf{B}^T \mathbf{m} N dV \right) \mathbf{p}$$

The forces due to surface traction $t^e$ at the joint are expressed using contact stresses $\sigma_{ct}$ as

$$\mathbf{F}_t^e = \int_V \mathbf{B}^T (\sigma_{ct}(\mathbf{a})) dV$$

To derive the Newton-Raphson formulation for finite elements with fracture behavior, consider the residual, given earlier,

$$\mathbf{R} = \left\{ \mathbf{F}_{ext} - \left( \int_V \mathbf{B}^T \mathbf{m} N dV \right) \mathbf{p} \right\} - \left\{ \int_V \mathbf{B}^T (\sigma_{ct}(\mathbf{a})) dV \right\}$$

where $\sigma_{ct}$ is the contact stress vector corresponding to the current aperture vector $\mathbf{a}$.

The Newton-Raphson formulation for single variable is given as

$$\left( \frac{\partial f}{\partial \Delta u} \right)^{(i-1)} \Delta u^{(i)} = \Delta g^{(i)} + \Delta f^{(i-1)}$$

where the residual at iteration $i$ of time step $t + \Delta t$ is written as

$$\Delta g^{(i)} = \Delta f^{(i)}$$

The N-R formulation for the joint element then can be written as

$$\left( \frac{\partial f}{\partial \Delta u} \right)^{(i-1)} \Delta u^{(i)} = \left\{ \mathbf{F}_p^e - \left( \int_V \mathbf{B}^T \mathbf{m} N dV \right) \mathbf{p} \right\} - \Delta \left\{ \int_V \mathbf{B}^T (\sigma_{ct}(\mathbf{a})) dV \right\}$$

To evaluate the Jacobian, let us first look at the contact stresses. The contact stresses are function of current apertures and in vector form, we can write the Jacobian term as
\[
\frac{\partial (f)}{\partial \Delta \mathbf{u}} = \frac{\partial}{\partial \Delta \mathbf{u}} \left( \int_{V} \mathbf{B}^T (\mathbf{\sigma}_{el} (\mathbf{a})) dV \right)
\]
\[
= \int_{V} \mathbf{B}^T \left( \frac{\partial \mathbf{\sigma}_{el} (\mathbf{a})}{\partial \Delta \mathbf{u}} \right) dV
\]
\[
= \int_{V} \mathbf{B}^T \left( \frac{\partial \mathbf{\sigma}_{el} (\mathbf{a})}{\partial \mathbf{a}} \frac{\partial \mathbf{a}}{\partial \Delta \mathbf{u}} \right) dV
\]

where the vector \( \mathbf{a} \) of current apertures is defined as
\[
\mathbf{a} = \begin{bmatrix} a_x \\ a_y \\ a_z \end{bmatrix}
\]

Since we are neglecting the shear effects due to contact, we can write
\[
\frac{\partial \mathbf{\sigma}_{el} (\mathbf{a})}{\partial \mathbf{a}} = \begin{bmatrix} k_n_x & 0 & 0 \\ 0 & k_n_y & 0 \\ 0 & 0 & k_n_z \end{bmatrix}
\]

where the normal stiffness in direction \( d \) defined as
\[
k_n_d = \frac{\sigma_c}{m a_{0d}} \left( 1 - \frac{a_d}{a_{0d}} \right)^{1-m} m
\]

The expression for normal stiffness is obtained for Gangi’s model which gives the contact stress \( \sigma_d \) for given value of aperture \( a_d \) as
\[
\sigma_d = \sigma_c \left( 1 - \frac{a_d}{a_{0d}} \right)^{1-m} m
\]

We can write the aperture vector \( \mathbf{a} \) as
\[
\mathbf{a} = \begin{bmatrix} a_x \\ a_y \\ a_z \end{bmatrix} = \begin{bmatrix} u_{x,Top} - u_{x,Bottom} + a_x \\ u_{y,Top} - u_{y,Bottom} + a_y \\ u_{z,Top} - u_{z,Bottom} + a_z \end{bmatrix}
\]

If we define the surface displacement vector \( \mathbf{u}_s \) as follows
\[
\mathbf{u}_s = \begin{bmatrix}
    u_{s,\text{Top}} \\
    u_{y,\text{Top}} \\
    u_{z,\text{Top}} \\
    u_{s,\text{Bottom}} \\
    u_{y,\text{Bottom}} \\
    u_{z,\text{Bottom}} 
\end{bmatrix}
\]

then we can write

\[
\frac{\partial \mathbf{a}}{\partial \Delta \mathbf{u}} = \frac{\partial \mathbf{a}}{\partial \mathbf{u}_s} \frac{\partial \mathbf{u}_s}{\partial \Delta \mathbf{u}}
\]

Thus the Jacobian can be written as

\[
\left( \frac{\partial f}{\partial \Delta \mathbf{u}} \right) = \int_V \mathbf{B}^T \left( \frac{\partial \mathbf{\sigma}_{\text{el}}(\mathbf{a})}{\partial \Delta \mathbf{u}} \right) dV
\]

\[
= \int_V \mathbf{B}^T \left( \frac{\partial \mathbf{\sigma}_{\text{el}}(\mathbf{a})}{\partial \mathbf{a}} \frac{\partial \mathbf{a}}{\partial \mathbf{u}_s} \frac{\partial \mathbf{u}_s}{\partial \Delta \mathbf{u}} \right) dV
\]

Differentiating the aperture vector with respect to the surface displacement vector we get

\[
\frac{\partial \mathbf{a}}{\partial \mathbf{u}_s} = \begin{bmatrix}
1 & 0 & 0 & -1 & 0 & 0 \\
0 & 1 & 0 & 0 & -1 & 0 \\
0 & 0 & 1 & 0 & 0 & -1 
\end{bmatrix}
\]

Then we can write

\[
\frac{\partial \mathbf{\sigma}_{\text{el}}(\mathbf{a})}{\partial \Delta \mathbf{u}} = \begin{bmatrix}
    kn_x & 0 & 0 & -kn_x & 0 & 0 \\
    0 & kn_y & 0 & 0 & -kn_y & 0 \\
    0 & 0 & kn_z & 0 & 0 & -kn_z \\
    0 & 0 & 0 & 0 & 0 & 0 \\
    0 & 0 & 0 & 0 & 0 & 0 \\
    0 & 0 & 0 & 0 & 0 & 0 
\end{bmatrix} \frac{\partial \mathbf{u}_s}{\partial \Delta \mathbf{u}}
\]

\[
= \mathbf{T} \frac{\partial \mathbf{u}_s}{\partial \Delta \mathbf{u}}
\]

where we have defined the new stiffness vector \( \mathbf{T} \).

Now we can write the Jacobian as

\[
\left( \frac{\partial f}{\partial \Delta \mathbf{u}} \right) = \int_V \mathbf{B}^T \left( \frac{\partial \mathbf{\sigma}_{\text{el}}(\mathbf{a})}{\partial \Delta \mathbf{u}} \right) dV
\]

\[
= \int_V \mathbf{B}^T \left( \mathbf{T} \frac{\partial \mathbf{u}_s}{\partial \Delta \mathbf{u}} \right) dV
\]
The surface displacements \( \mathbf{u}_s \) are calculated from the nodal displacements as follows

\[
\begin{bmatrix}
\mathbf{u}^\text{Top}_x \\
\mathbf{u}^\text{Top}_y \\
\mathbf{u}^\text{Top}_z \\
\mathbf{u}^\text{Bottom}_x \\
\mathbf{u}^\text{Bottom}_y \\
\mathbf{u}^\text{Bottom}_z
\end{bmatrix}
= \begin{bmatrix}
0 & 0 & 0 & \ldots & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \ldots & 0 & 0 & 0 \\
0 & 0 & 0 & \ldots & 0 & N_4 & 0 & 0 & 0 & 0 & \ldots & 0 & N_8 & 0 \\
0 & 0 & 0 & \ldots & 0 & 0 & 0 & 0 & 0 & 0 & \ldots & 0 & 0 & N_8 \\
N_1 & 0 & 0 & \ldots & N_4 & 0 & 0 & N_5 & 0 & 0 & \ldots & N_8 & 0 & 0 \\
0 & N_1 & 0 & \ldots & 0 & 0 & 0 & 0 & N_5 & 0 & \ldots & 0 & 0 & 0 \\
0 & 0 & N_1 & \ldots & 0 & 0 & N_4 & 0 & 0 & 0 & \ldots & 0 & 0 & 0 \\
\end{bmatrix}
\begin{bmatrix}
\mathbf{u}^1_x \\
\mathbf{u}^1_y \\
\mathbf{u}^1_z \\
\mathbf{u}^4_x \\
\mathbf{u}^4_y \\
\mathbf{u}^4_z \\
\mathbf{u}^5_x \\
\mathbf{u}^5_y \\
\mathbf{u}^5_z \\
\mathbf{u}^8_x \\
\mathbf{u}^8_y \\
\mathbf{u}^8_z
\end{bmatrix}
\]

which in vector form is written as

\[
\mathbf{u}_s = \mathbf{N}_c \Delta \mathbf{u}
\]

The complete matrix \( \mathbf{N}_c \) is given as

\[
\mathbf{N}_c = \begin{bmatrix}
0 & 0 & 0 & N_2 & 0 & 0 & N_4 & 0 & 0 & 0 & \ldots & 0 & 0 & N_6 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & N_1 & 0 & 0 & N_3 & 0 & 0 & \ldots & 0 & 0 & 0 & 0 & 0 & 0 & N_7 & 0 & 0 & N_4 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \ldots & 0 & 0 & N_5 & 0 & 0 & N_6 & 0 & 0 & N_7 & 0 & 0 & N_4 & 0 \\
N_1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \ldots & 0 & 0 & N_5 & 0 & 0 & N_6 & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & N_1 & 0 & 0 & N_3 & 0 & 0 & 0 & 0 & 0 & \ldots & 0 & 0 & N_5 & 0 & 0 & N_6 & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & N_1 & 0 & 0 & N_3 & 0 & 0 & N_4 & 0 & 0 & \ldots & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
\end{bmatrix}
\]

Also, noting that

\[
\frac{\partial \mathbf{u}_s}{\partial \Delta \mathbf{u}} = \mathbf{N}_c
\]

we can write the expression for Jacobian as

\[
\left( \frac{\partial \mathbf{f}}{\partial \Delta \mathbf{u}} \right) = \int_V \mathbf{B}^T \left( \frac{\partial \mathbf{\sigma}_{et}(\mathbf{a})}{\partial \Delta \mathbf{u}} \right) dV
\]

\[
= \int_V \mathbf{B}^T \mathbf{T} \mathbf{N}_c dV
\]

Define the elemental stiffness \( \mathbf{K}^e(\Delta \mathbf{u}) \) for the joint element as
Then the Newton-Raphson formulation for the volume element with fracture behavior can be represented as

$$\begin{align*}
\left[ K^e(\Delta u) \right]^{(i-1)} \delta \Delta u^{(i)} = & \left[ F^{ext} - \int_V B^T m N dV \right] p^{(i)} - t^{(i)} \left( \int_V B^T (\sigma_{et}(a)) dV \right) \\
= & \int_V B^T T N_C dV
\end{align*}$$

Calculation and Modification of Fracture properties

The fracture porosities and permeabilities are as described below.

Permeability

The fracture permeability is determined using the Cubic law, which is based on the derivation for flow through fracture surfaces assuming laminar flow between parallel plates, for the relation between the fracture apertures and permeability. The permeability in principal direction \(i\), is calculated from the apertures in the other two principal directions \(j\) and \(k\) as follows (Rutqvist et al., 2002)

$$k_i = \frac{a_j^3}{12} + \frac{a_k^3}{12}$$

As the aperture gets modified based on the displacement of the fracture walls, the permeability will automatically get modified.

Porosity

The initial porosity, \(\phi_0\) for the fracture is specified by the user. Then the fracture porosity will be modified as function of apertures as given below (Rutqvist et al., 2002)

$$\phi = \phi_0 \left( \frac{\sum_{d=1}^3 a_d}{\sum_{d=1}^3 a_{id}} \right)$$

where \(d\) denotes the principal directions.

Demonstration examples

Two problems demonstrating the fracture implementation are described here. The first problem is an axisymmetric 3D problem with a single planar fracture. Cold water is injected into the fracture and the thermal effects on the fracture aperture are emphasized. The fracture opening is shown in the Figure 3.50 in middle of the simulation run.
The second problem demonstrates the ability to handle multiple fracture networks. A set of fractures in both directions are introduced in the domain for this 2D problem. Cold water is injected and the effect of thermal stresses on the aperture and flow is visualized. The multiple material assignments are shown in Figure 3.51. The deformed meshes with thermal contours at different times are also shown in Figure 3.52.
Figure 3.51 Material assignment for multiple fracture problem.

Figure 3.52 Pressure and temperature contours in deformed mesh at 10 and 5e5 secs.

3.4.3.5 Five spot example
The following problem considers a large field with wells arranged in a “five-spot” geometric pattern as shown in Figure 3.53. This is an example problem 4 in TOUGH2 user’s manual (Pruess et al., 1999). Only half of the domain is modeled due to symmetry.

![Diagram of five-spot geothermal well pattern model](image)

**Figure 3.53. Five-spot geothermal well pattern model.**

The problem is solved using one way coupling and only porous media assumption. The boundary conditions for the displacement problem are roller support on all the sides and bottom of the reservoir, and the top surface is free.

**Simulation**

A 21 x 11 x 6 TOUGH2 mesh was used to generate a finite element model for the five-spot problem. The problem parameters are listed in Table 24. The simulation was carried in two stages. Initially, a steady state run was carried out to obtain the equilibrium condition and then a transient run to model the five-spot problem.

**Results and conclusion**

During this initial run, the liquid phase in the reservoir settles down due to gravity as seen in Figure 3.54 and hence the pressure will increase in the lower part of the reservoir. Due to this pressure increase the reservoir expands as shown in Figure 3.55. Then the transient one way simulation is carried out with the injection and production rates as specified in the parameter table.
Table 24. Simulation Parameters (Five-Spot Example)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Young’s Modulus, (E)</td>
<td>1.44e10 Pa</td>
</tr>
<tr>
<td>Poisson’s ratio, (\nu)</td>
<td>0.2</td>
</tr>
<tr>
<td>Permeability, (k)</td>
<td>6.0e-15 m(^2)</td>
</tr>
<tr>
<td>Thermal Conductivity, (\lambda)</td>
<td>2.1 W/m C</td>
</tr>
<tr>
<td>Specific Heat, (c)</td>
<td>1000 J/ kg C</td>
</tr>
<tr>
<td>Thermal Expansion Coefficient, (\alpha_T)</td>
<td>7.5e-7 1/C</td>
</tr>
<tr>
<td>Biot-Willis Coefficient, (\alpha)</td>
<td>1.0</td>
</tr>
<tr>
<td>Density of rock, (\rho_s)</td>
<td>2650 kg /m(^3)</td>
</tr>
<tr>
<td>Initial reservoir temperature, (p_0)</td>
<td>300 C</td>
</tr>
<tr>
<td>Initial gas saturation, (S_g)</td>
<td>0.01</td>
</tr>
<tr>
<td>Injection rate (full well basis)</td>
<td>30 kg/s</td>
</tr>
<tr>
<td>Injection enthalpy</td>
<td>500 kJ/ kg</td>
</tr>
<tr>
<td>Production rate (full well basis)</td>
<td>30 kg/s</td>
</tr>
</tbody>
</table>

Figure 3.54. Gas phase saturation at the end of steady state simulation run.
Figure 3.55. Pressure and deformation at equilibrium condition.

Figure 3.56. Gas phase saturation at the end of 36.5 years.
The injection is done at lower temperature than the reservoir temperature. The profiles of gas phase saturations and stresses in Z direction at the end of 36.5 years are shown in Figure 3.56 and Figure 3.57, respectively. Due to cooling, the rock near the injection well contracts and a trench like formation is seen in the cooled region. But near the injection well there is an expansion due to increase pressure due to injection. Also, we can see the increased gas phase saturation near the production well areas due to the lowered pressure due to production.

The simulation shows the ability of T2STR to model field case problems. It also shows the restart capability of T2STR allowing the user to obtain the equilibrium condition and then carry out the transient simulation. This also would enable user to carry out the history matching simulation and use the end result for a predictive model.

Creating the FEM file (*.g3d), T2STR and material records, and GUI
A new GUI is created to facilitate the creation of the corresponding *.g3d file required to run T2STR. It also generates the T2STR record and the material record modification line in the ROCKS records. This helps to avoid errors due to inconsistency in input data and provides a user friendly interface. The file INSITU, specifying the insitu stresses, also can be generated using the same GUI.

Generally, the user had the responsibility to set values for the materials of the nodes (TOUGH2 elements) in the ROCKS record, consistent with the ones specified for elements on the finite element side. But the new GUI generates the material record (to be added in the ROCKS record of TOUGH2) using the values provided to generate the material record in *.g3d file. The multiple rock and fracture material modeling facility can also be addressed using the GUI for generating the related material information to be modified in TOUGH2 input file. Now user can also specify the tolerance for the displacements. It allows the user to control the convergence and accuracy of the solution.
Figure 3.58. Snapshots of new GUI.
### References


3.5 Effects of Cold Water Injection on Fracture Aperture and Injection Pressure (Ahmad Ghassemi)

3.5.1 Background and Objectives

In this report we use a 3D heat extraction/thermoelastic displacement discontinuity model to study fracture slip in response to fluid pressure and cooling of the rock under a given in-situ stress field. Using this approach, we estimate the effect of each mechanism on fracture slip with reference to the Coso geothermal field. The results indicate that thermal stress can play a major role in increasing fracture slip and permeability enhancement.

3.5.2 Injection/Extraction for an Arbitrarily Shaped Fracture

Consider a fracture with arbitrary geometry shown in Figure 3.59. The fracture surface is divided into 3384 rectangular elements. The heat extraction operation involves 3 wells: one injection well with flow rate 40 ℓ/s, and two extraction wells each with flow rate 20 ℓ/s. The rock and fluid properties are given in Table 25. The fracture is considered to be at a depth of 2330 m with an in-situ stress filed of σv =60.13, MPa; σhmin =34.81 MPa; and σHmax =50.88 MPa, and a pore pressure of P=17.4 MPa. Upon rotating the in-situ stresses to the local fracture coordinate system, we get: σzz =41.1 MPa, σxx=0 MPa, and σyy=11.0 MPa. The fracture surface is considered to have a dip angle of 60° and to strike in the direction of σHmax (north). It is assumed to have friction angle of φ=30° and a dilation angle of 3°. The injection period is considered to be 3
months and the fluid pressure in the fracture is assumed to be uniform and equal to 25 MPa. However, to calculate the actual flow field for arbitrary shape fracture, the equation for the incompressible fluid flow is used. For the current conditions, the resultant flow field is shown in Figure 3.59.

Figure 3.60 shows the fracture slip when the thermal stresses are not included in the analysis. We can observe that the slip occurs where the pore pressure is sufficiently high and the rock is not constrained, with a maximum slip of 9 mm.

Let us now consider the influence of rock cooling. Figure 3.61 illustrates the temperature distribution on the fracture surface after 3 months of operation. The relatively small blue about 30°C around the injection well indicates that heat depletion has not reached a large part of the reservoir at that time. Figure 3.62 is a plot of the normal stress on the fracture surface after 3 months of injection. A large tensile region (tension is positive in the plots) is developed around the injection well. Outside of the fracture region, we find compression zones. We also notice that compression zones develop just behind the extraction wells. We notice some error at and near the injection/extraction wells, where a flow singularity exists.

The shear slip in the y-directions is shown in Figure 3.63. The fracture has undergone slip over a large area with a maximum value of 7 cm. This is significantly larger that the 9 mm (maximum) slip when thermal stresses were not considered. This is a clear indication of the importance of thermal stresses in fracture slip.

The slip and opening of the fracture result in fracture permeability enhancement. This is illustrated in Figure 3.64, which shows the distribution of $k = U^2_{zz}/12$. It can be seen that the permeability has substantially increased compared to its initial value of $8.3 \times 10^{-8}$ m$^2$. 
Figure 3.59. Fluid flow in a fracture with arbitrary geometry. One injection well and two extraction wells.
Figure 3.60. Shear slip in the y-direction in the absence of thermal stresses.

Figure 3.61. Temperature distribution on the fracture after 3 months of injection
Figure 3.62. Normal stress distribution on the fracture plane (Pa).

Figure 3.63. Distribution of fracture slip in the y-direction after 3 months of injection/extraction.
Figure 3.64. Permeability distribution after injection/extraction and slip (the initial fracture permeability was $8.3 \times 10^{-8} \text{ m}^2$).

Table 25. Input data for the simulations.

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$E$</td>
<td>Young's modulus</td>
<td>65.0</td>
</tr>
<tr>
<td>$\nu$</td>
<td>Poisson's ratio</td>
<td>0.185</td>
</tr>
<tr>
<td>$\rho_r$</td>
<td>rock density</td>
<td>2650</td>
</tr>
<tr>
<td>$\rho_w$</td>
<td>water density</td>
<td>1000</td>
</tr>
<tr>
<td>$c_r$</td>
<td>rock heat capacity</td>
<td>790</td>
</tr>
<tr>
<td>$c_w$</td>
<td>water heat capacity</td>
<td>4200</td>
</tr>
<tr>
<td>$\kappa$</td>
<td>thermal diffusivity</td>
<td>$5.1 \times 10^{-6}$</td>
</tr>
<tr>
<td>$\alpha_T$</td>
<td>rock linear thermal exp. coefficient</td>
<td>$8.0 \times 10^{-6}$</td>
</tr>
<tr>
<td>$Q$</td>
<td>injection rate</td>
<td>40</td>
</tr>
<tr>
<td>$T_R$</td>
<td>rock temperature</td>
<td>350</td>
</tr>
<tr>
<td>$T_{\text{inj}}$</td>
<td>injection water temperature</td>
<td>86</td>
</tr>
<tr>
<td>$w$</td>
<td>initial avg. fracture aperture for flow</td>
<td>$10^{-3}$</td>
</tr>
</tbody>
</table>
Volume 2

Final Report for the Portion of the Project Focused on the Southwest Compartment of the Coso Geothermal Field

September, 2007

Creation of an Enhanced Geothermal System through Hydraulic and Thermal Stimulation

DE-FC07-01ID14186

Peter Rose¹, Principal Investigator; Steve Hickman³, Co-Principal Investigator; Jess McCulloch², Co-Principal Investigator; Nick Davatzes³, Joseph M. Moore¹, Katie Kovac¹, Mike Mella¹, Bruce Julian³, Gillian Foulger³, Frank Monastero⁴

¹EGI, University of Utah
²Coso Operating Company
³U.S. Geological Survey
⁴GPO, Naval Air Weapons Station
Table of Contents

INTRODUCTION ........................................................................................................................................... 3

TASK OBJECTIVES AND ACCOMPLISHMENTS ......................................................................................... 4

WORKOVER AND STIMULATION OF 46A-19RD (JESS MCCULLOCH, PETE ROSE, STEVE HICKMAN,
AND NICK DAVATZES) ................................................................................................................................. 4

  Background and Objectives .......................................................................................................................... 4
  Accomplishments .......................................................................................................................................... 5
  Plans .............................................................................................................................................................. 5

PETROGRAPHY, PETROLOGY, AND GEOCHEMISTRY (KATIE KOVAC, JOE MOORE, TIANFU XU, AND
KARSTEN PRuess) ........................................................................................................................................ 6

  Background and Objectives ........................................................................................................................ 6
  Accomplishments ......................................................................................................................................... 6

Petrology and Petrography

  Overview .................................................................................................................................................... 6
  Well 46A-19RD ......................................................................................................................................... 7
    Lithology .................................................................................................................................................. 7
    Hydrothermal Alteration ........................................................................................................................ 14
    Clay Mineralogy ..................................................................................................................................... 17
    The Target Stimulation Zone .................................................................................................................. 18
  Summary and Conclusions ....................................................................................................................... 20

Well 32A-20 .................................................................................................................................................. 20

Reactive Transport Modeling .......................................................................................................................... 24

  Overview .................................................................................................................................................. 24
  The 34-9RD2 1-D Model ............................................................................................................................ 24
  The 46A-19RD 1-D Model ........................................................................................................................ 35
  References .................................................................................................................................................. 35

MICROSEISMS (FRANK MONASTERO, GILLIAN FOULGER AND BRUCE JULIAN) ........................................... 57

  Background and Objectives ....................................................................................................................... 57
  Accomplishments 2003-2006 .................................................................................................................... 58

MECHANICAL, MINERALOGICAL, AND PETROPHYSICAL ANALYSIS OF FRACTURE PERMEABILITY
(NICK DAVATZES AND STEVE HICKMAN) .................................................................................................. 99

  Background and Objectives ....................................................................................................................... 99
  Accomplishments ..................................................................................................................................... 100

  Stress and Faulting in the Coso Geothermal Field: Update and Recent Results from the East Flank and
  Coso Wash ................................................................................................................................................. 100
    The Fault System .................................................................................................................................... 101
    Physical Properties of Rocks in the Geothermal Field ............................................................................. 104
    Stress Measurements ............................................................................................................................... 111
    Stress Magnitudes in the East Flank and Coso Wash ............................................................................. 114
    Discussion .............................................................................................................................................. 125
  Conclusions ............................................................................................................................................... 130
  Sensitivity to Bottom-Hole Shape ............................................................................................................ 131
  Acknowledgments ..................................................................................................................................... 131
  References ............................................................................................................................................... 131

Appendix A: Physical Properties of Core obtained from well 34-9RD2 ....................................................... 134

2
1.0 Introduction

The Coso geothermal field is an excellent setting for testing Enhanced Geothermal System (EGS) concepts. Fluid temperatures exceeding $350^\circ$C have been measured at depths less than 10,000 ft and the reservoir is both highly fractured and tectonically stressed. However, some of the wells within the reservoir are relatively impermeable. High rock temperatures, a high degree of fracturing, high tectonic stresses and low permeability are the qualities that define an ideal candidate-EGS reservoir. We have therefore assembled a team of capable scientists and engineers for the purpose of developing and evaluating an approach for the creation of an EGS within the Coso reservoir. In addition, the Navy Geothermal Program Office is providing valuable data from a regional Coso seismic survey and localized east and west flank microseismic studies.

Key to the creation of an EGS is an understanding of the relationship among natural fracture distribution, fluid flow, and the ambient tectonic stresses that exist within a resource. Once these relationships are determined, it is possible to design a hydraulic and thermal stimulation of a candidate injection well as the first step in the creation of a heat exchanger at depth. The success of the experiment can then be quantified through hydraulic, microseismic, geomechanical, and geochemical measurements. From the lessons learned at Coso, it will be possible to design and create an EGS wherever appropriate tectonic, thermal and hydraulic conditions exist, thereby allowing geothermal operators to greatly extend their developmental reach beyond the relatively few known geothermal resources.

The objective of the EGS project at Coso was to stimulate one or more low permeability injection wells through a combination of hydraulic, thermal and chemical methods and to hydraulically connect the well(s) to at least one production well. Thus, the objective was not only to design and demonstrate an EGS on the periphery of an existing geothermal reservoir, but to understand the processes that control permeability enhancement. The primary analytical tools used include borehole logs for imaging fractures and determining regional stresses, petrographic and petrologic analyses of borehole cuttings, petrophysical measurements of core samples, geophysical methods including microseismology and magnetotelluric (MT) studies, structural analysis, fluid-flow modeling, and geochemical modeling. Lessons learned at Coso will make it possible to design and create an EGS wherever appropriate tectonic, thermal and hydraulic conditions exist, thereby allowing geothermal operators to greatly extend their developmental reach beyond the relatively few naturally occurring hydrothermal resources.

The initial focus for the EGS project at Coso was the east margin of the field where injection wells had been drilled into high-temperature, low-permeability rock in close proximity to some of the field’s most productive wells (see Figure 2.1-1). These wells of marginal injectivity provided excellent laboratories for studying hydraulic stimulation techniques that, if proven successful, could be of great utility both for EGS activities but for conventional geothermal programs as well. A target well was selected (designated 34-9RD2) and the focus of the program was directed towards designing and conducting a
hydraulic stimulation of this well. Unfortunately, and for reasons described in the FY2005 annual report for this project, the experiment was never realized.

The focus of the program was then moved to the southwest portion of the field and the hot deep impermeable well 46A-19RD was selected as a stimulation target. This report focuses on the experiments and analyses associated with the design and attempted stimulation of that well.

2.0 Task Objectives and Accomplishments

2.1 Workover and Stimulation of 46A-19RD (Jess McCulloch, Pete Rose, Steve Hickman, and Nick Davatzes)

2.1.1 Background and Objectives

The focus for FY2007 was the testing and stimulation of injection well 46A-19RD in the southwest region of the Coso field (see Figure 2.1-1). This well was drilled into the hottest portion of the Coso field to a total vertical depth of approximately 12,700 ft. Fluid injection into the well had been very limited because permeability in the bottom of the well, where injection was needed, was very low. The objective of the stimulation experiment was to increase the injectivity of 46A-19RD to the point that it will accept separated brine at a rate of 500 gpm at a wellhead pressure of 100 psi or less.
Figure 2.1-1. Plan view of the southwest corner of the Coso geothermal field showing wellhead locations and trajectories of target stimulation well 46A-19RD (in red) and surrounding production wells (in blue).

2.1.2 Accomplishments

A drill rig was moved to the 46A-19RD pad for the purpose of pulling the existing liner, which extended from approximately 2500 ft to the total well depth of approximately 13,000 ft. Then, new casing would be installed and cemented to a depth of 10,000 ft, leaving an ‘open-hole’ section between 10,000 ft and total depth. The Navy’s temporary seismic array had already been deployed around 46A-19RD to monitor any seismicity associated with the subsequent stimulation experiment. That experiment would then be performed by injecting at pressures below the minimum horizontal stress while monitoring the development of the microseismic cloud and the associated inferred permeability. Finally, a circulation test, complete with tracer testing and continued microseismic monitoring, would be conducted to determine the success of the stimulation experiment.

After approximately one month of trying, the drill crew failed to remove the liner, a crucial step in the stimulation experiment. After discussing all options involving leaving the liner in place, it was concluded that the likelihood of achieving our objectives was
low and the project was abandoned. What follows in this report is a summary of the tasks that were conducted in planning and designing the aborted stimulation experiment.

2.2 Petrography, Petrology, and Geochemistry (Katie Kovac, Joe Moore, Tianfu Xu, and Karsten Pruess)

2.2.1 Background and Objectives

The chemical interactions between host rocks and injection fluids, by causing the dissolution or precipitation of minerals, can either enhance or destroy permeability. Results of recent studies such as those of Durst (2002) and Bachler (2003) suggest that these chemical interactions can greatly impact the performance of EGS reservoirs over the long-term. Reactive chemical transport simulation can therefore serve as a useful tool in managing injection strategies.

To assess these interactions and their potential effects on the Coso experiment, modeling efforts using the program TOUGHREACT (Xu and Pruess, 2001; Xu et al., 2006) were initiated. TOUGHREACT is a non-isothermal reactive geochemical transport code developed by T. Xu and K. Pruess at Lawrence Berkeley National Labs. Its physical and chemical process capabilities and solution techniques are outlined in Xu and Pruess (2001). This simulator can be applied to 1-, 2-, and 3-dimensional porous, fractured media. Physical and chemical properties can be homogeneous or heterogeneous, and solid, liquid, and gaseous phases of chemical species can be present. Simulations modeling both benchtop flow reactor laboratory experiments and field experiments have been undertaken.

To correctly simulate the chemical reactions and processes that occur in geothermal locations, accurate and detailed knowledge about the geology of the field must be collected. Lithologic, petrographic, mineralogic, and other relevant observations are obtained through petrologic and petrographic studies and used as inputs to the TOUGHREACT models.

2.2.2 Accomplishments

2.2.2.1 Petrology and Petrography

2.2.2.1.1 Overview

This year, complete petrologic and petrographic assessment of well 46A-19RD was initiated and completed. Cuttings from the well were studied and analyzed for lithology, relative amount of pervasive alteration, pervasive alteration mineralogy, vein mineralogy, vein mineral paragenesis, presence of tectonic brecciation, and other features. These data were supplemented with thin section, x-ray diffraction, and fluid inclusion studies. Scale samples from well 32A-20 were also examined for mineralogy and paragenetic sequence of scale minerals.
2.2.2.1.2 Well 46A-19RD

2.2.2.1.2.1 Lithology

The major rock types found in this well are: quartz diorite, granodiorite, granite, and granophyre (listed in order of most to least mafic). Photographs of the major rock types are shown in Figures 1-4. The quartz diorite is the most mafic of the abundant rock types found in well 46A-19RD. It generally contains: 12-14 wt% quartz, 35-38% plagioclase feldspar, 3-8% potassium feldspar, 15-30% micas, 0-8% hornblende, varying chlorite and 0-2% epidote (Lutz and Moore, 1997). Based on the varying proportions of hornblende, potassium feldspar, biotite, and epidote, the diorites are further subdivided into hornblende-biotite-quartz diorite and biotite-quartz diorite. The hornblende-biotite-quartz diorite tends to be more mafic. It is characterized by more hornblende, epidote, and sphene than the biotite-quartz diorite, and very little potassium feldspar. The biotite-quartz diorite is more felsic in composition, contains more potassium feldspar and biotite, and generally lacks epidote as alteration. In this well, the hornblende-biotite-quartz diorite was more common. The diorites generally show at least some foliation.

The granodiorite is intermediate in composition between the diorite and the granite. It typically consists of 27 wt% quartz, 31% plagioclase, 31% potassium feldspar, 3% calcite, 7% biotite, and 1% chlorite (Lutz and Moore, 1997). This rock type dominates below about 11,500 ft. In East Flank Coso study wells, this rock type was commonly weakly altered. In the deepest portion of 46A-19RD, however, the granodiorite displays a greater degree of pervasive alteration.

Granites are the least common of the rock types present, and display a large range in grain size. The granites contain approximately 36 wt% quartz, 22% plagioclase feldspar, 33% potassium feldspar, 3% calcite, <7% biotite and 2% chlorite. Two textural varieties are present. Most of the granite is medium-to-coarse grained. However, between 4720-4780 ft and 11,350-11,500 ft the texture is granophytic and the rock contains phenocrysts of plagioclase, potassium feldspar and resorbed quartz, surrounded by intergrowths of feldspar and quartz. The glass at 4760 ft suggests rapid cooling rock. Figures 4 and 5 display both textures of the granophyre. Similar granophyric textures were not identified in any of the other Coso wells. Variations in grain size suggest that the granophyre represents a dike and may be contemporaneous with the Miocene rocks described in Whitmarsh (1998).
Figure 2.2-1. The hornblende biotite quartz diorite in thin section (field of view ~1mm across). Note the foliated texture. Sphene, hornblende, and biotite are all visibly present.

Figure 2.2-2. The biotite granodiorite as found in the East Flank of the Coso field in thin section (field of view ~ 1mm across). Note the relatively low degree of pervasive alteration.
Figure 2.2-3. The granite as it appears in thin section (field of view ~1mm across).

Figure 2.2-4. The granophyre from well 46A-19RD at 11,380 ft depth. Note the phenocrysts of quartz and feldspar. See text for further discussion.
Figure 2.2-5. The granophyre at 4760 ft where it displays a glassy texture. See text for further discussion.

The well log for 46A-19RD shows that this well is very hot, reaching temperatures well over 300°C (Figure 6). In general, the lithology of this well was similar to that of other Coso study wells. The exception to this would be the presence of granophyre, which has not been identified in any of the other Coso wells in this study to date.

Figures 7, 8, and 9 show that most of the well is dominated by the quartz diorites. However, the deepest interval of the well (11,500 ft-depth) is dominated by granodiorite. Generally, this granodiorite is more altered and veined than it appeared in the East Flank study wells. The deep portion of the well also contained several zones of strong pervasive alteration named ‘alteration zones.’
Figure 2.2-6. The summary log for well 46A-19RD. Note the lack of lost circulation zones in the deep portion of the well. Also note the altered zones. See text for discussion.
Figure 2.2-7. Summary of petrologic and petrographic observations on the shallow interval of well 46A-19RD. Lithology color code as follows: dark green = hornblende biotite quartz diorite, yellow = biotite quartz diorite, orange = biotite granodiorite, pink = granite, purple = granophyre, light green = alteration zone.
Figure 2.2-8. Summary of petrologic and petrographic observations on the middle interval of well 46A-19RD. Lithology color code as described above.
2.2.2.1.2.2 Hydrothermal Alteration

The altered zones can be readily identified in the chip boards by their green color and abundance of epidote, pyrite, chlorite, and white micas (Figures 10, 11, 12). Petrographically, the sheet silicates appear to be illite. This type of alteration occurs most commonly within narrow intervals of the hornblende biotite quartz diorite. Major alteration zones are located within the well at approximately: 5700-5720 ft, 6540-6560 ft, 7940-8020 ft, 8240-8260 ft, 10740-10780 ft, and 11200-11350 ft. Three of the upper altered zone locations correlate with zones of lost circulation. However, the two deepest altered zones do not.

The vein assemblages found in well 46A-19RD include: calcite +/- chlorite +/- hematite, adularia + pyrite +/- quartz, epidote +/- pyrite +/- trace other sulfides, and quartz. The paragenetic sequence of vein minerals based on observations from this well is shown in Figure 13. The earliest documented vein assemblage consists of chlorite, epidote, pyrite, quartz, and minor sulfides in the quartz diorites. The youngest stages are dominated by calcite +/- chlorite, quartz, hematite, and minor wairakite (Figure 14).
Figure 2.2-10. Just above the first alteration zone. See text for discussion.

Figure 2.2-11. 10,740-10,780 ft: Altered Zone 1. See text for discussion.

Figure 2.2-12. Just below the first alteration zone. See text for discussion.
Figure 2.2-13. The mineral paragenetic sequence based on observations from well 46A-19RD. Generally, the assemblages show a progression from hotter to cooler assemblages over time. See text for discussion.
Both typical caprock (smectite, illite-smectite) and reservoir (epidote, wairakite, illite) minerals have been identified in the well. The observed paragenetic sequence generally agrees with that observed in East Flank wells (Kovac et al., 2005; Kovac et al., 2004). Two generations of reservoir-mineral epidote appear to be present, a coarse-grained epidote that forms sealed veins within the quartz diorite and granodiorite, and vuggy veins containing small euhedral crystals of green epidote. This epidote is interpreted as representing a younger generation of mineralization, perhaps geothermal in age. Similar epidote has been encountered in nearby well 72-19. In well 72-19, located within the upflow zone in the southwestern portion of the field, wairakite postdates the similar assemblage quartz + acicular epidote + pyrite + chlorite, at 6100 ft. The presence of epidote indicates that the temperature range of deposition of these veins is >250-300°C (Henley and Ellis, 1983; Browne, 1984). In general, the documented assemblages trend from hotter to cooler as time progresses. However, preliminary fluid inclusion studies on the youngest blocky calcite veining indicate higher temperatures, consistent with the increasing present-day temperatures.

2.2.2.1.2.3 Clay Mineralogy

X-ray diffraction studies were conducted of select samples over the depth of the well. The clay minerals smectite, kaolinite, interlayered illite-smectite, illite, chlorite, and chlorite-smectite were identified. The summary of clay mineralogy vs. depth is shown in Figure 15. The present day temperature profile is shown at the left. In geothermal systems, smectite is considered stable up to temperatures of 180°C (Henley and Ellis, 1983), and interlayered illite-smectite to temperatures of 225°C (Henley and Ellis, 1983.) In comparison to the present temperature profile, smectite's disappearance is consistent with the ~180°C depth. However, illite-smectite persists to depths where temperatures are much higher than 225°C. This suggests recent heating, such that the clays have not yet re-equilibrated.
Figure 2.2-15. Clay mineralogy as percent abundance of total clays versus depth for well 46A-19RD. The present day temperature profile is shown at the left for comparison. See text for further discussion.

2.2.2.1.2.4 The Target Stimulation Zone

The interval from 10,000 ft to depth in the well is of special interest, as this is the target zone in the hydraulic stimulation experiment. Currently, this deepest portion of the well lacks lost circulation zones; however, there are several indications that this zone was at least somewhat permeable to fluids in the past.

Several zones containing tectonic breccia were identified in the well from petrographic analysis around approximately: 9,400 ft, 9,700 ft, 10,000 ft, 10,200 ft, 10,400 ft, 11,200-11,400 ft, and 11,900 ft - depth. Frequently, both the feldspars and quartz display strained grains in these intervals. Often, these zones of intense brecciation correlate with zones of heavy alteration and/or increased veining. For example, in the alteration zone at 11,200 ft, many fragments of tectonic breccia are evident. In many instances, the zones of tectonic brecciation are at least partially infilled by later calcite +/-quartz +/-adularia +/- chlorite veining, indicating that these more recent veins were deposited post-brecciation (Figure 16). The deepest portion of this well (~11,500 ft--total depth) is dominated by relatively altered and tectonically fractured granodiorite. Figure 17 displays this granodiorite being infilled by younger calcite+minor chlorite veining.
Figure 2.2-16. A closeup of young calcite+chlorite veining infilling brecciated granodiorite host rock. Possibly, several different stages of calcite veining are present.

Figure 2.2-17. A closeup from the deep interval of well 46A-19RD of altered granodiorite. Note the secondary sericite and infilling calcite.
2.2.2.1.2.5 Summary and Conclusions

Diorite, granodiorite and granite are the most common rock types in well 46A-19RD. These represent the dominant lithology found in other East and West Flank Coso wells. Granodiorite and quartz diorites are abundant and the most extensively altered and brecciated. The granites and granophyres are the youngest rocks and are only weakly altered. At 11,350 - 11,500 ft, they intrude brecciated and altered granodiorite. Brecciation suggests the contact represents a shear zone that was permeable in the past, as evidenced by heavy pervasive alteration and a kick in the mud temperatures.

The intervals of well 46A-19RD targeted for hydraulic stimulation are locally strongly brecciated and altered. The alteration consists mainly of chlorite, pyrite, epidote, and white clays. These minerals are overprinted by veins of quartz, adularia and later calcite. Based on petrography, the zones most likely to fail during hydraulic stimulation will be at the granophyre-quartz diorite/granodiorite contacts.

The temperatures indicated by the alteration minerals are much lower than would be predicted from the present day downhole temperatures. However, late-stage fluid inclusion temperatures are in good agreement with present-day temperatures. These relationships imply the system is currently being reheated. These recent thermal stresses may have played a role in developing the present fracture network.

2.2.2.1.3 Well 32A-20

Studies of scale samples provided by a nearby well, 32A-20, offered some insight into the mineralogy of the scale. Samples from 4040 ft, 5031 ft, 6149 ft, and an unknown depth were analyzed by means of X-ray diffraction analysis. Additionally, the sample from unknown depth was analyzed by SEM (scanning electron microscope) studies. Compositionally, the scale is comprised of mostly carbonates, specifically calcite and aragonite with minor magnesite and siderite. Small amounts of clays and possibly quartz are also present. Figure 18 shows an SEM photo of the sample from unknown depth. It displays that three distinct layers are present in the sample: a calcite layer, a small septochlorite layer, and an aragonite layer. Spot energy dispersive x-ray analyses confirmed the composition of each layer (Figures 19 and 20).
Figure 2.2-18. The SEM image of the scale sample from unknown depth in well 32A-20. The three different layers visible in hand sample are also evident in the photograph.
Figure 2.2-19. The energy dispersive x-ray spectra displayed by the first layer (calcite) in the sample from unknown depth in well 32A-20.
Figure 2.2-20. The energy dispersive X-ray spectra displayed by the second layer (septochlorite) of the sample from unknown depth in well 32A-20.

X-ray diffraction analysis was used on each of the samples to confirm their bulk mineralogy. Table 1 displays the composition of each sample. Calcite and aragonite are the dominant minerals present in these scales. Trace amounts of quartz, plagioclase, and chlorite are present in some of the samples. The source of these trace minerals is less certain. The SEM images of the sample from unknown depth clearly indicates that some of the chlorite (possibly with quartz) is present in the scale itself; however, another possible source for these minerals is simply that they represent entrained wallrock.
Table 2.2-1. Scale mineralogy of the 32A-20 samples determined by x-ray diffraction.

<table>
<thead>
<tr>
<th>Minerals</th>
<th>Unknown Depth (blocky mineral)</th>
<th>Unknown Depth (fibrous mineral)</th>
<th>Bulk sample 4040 ft</th>
<th>Bulk sample 5031 ft</th>
<th>Bulk sample 6139 ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aragonite</td>
<td>tr</td>
<td>M</td>
<td>m</td>
<td>m</td>
<td></td>
</tr>
<tr>
<td>Calcite</td>
<td>M</td>
<td>tr</td>
<td>M</td>
<td>M</td>
<td>M</td>
</tr>
<tr>
<td>Quartz</td>
<td>tr?</td>
<td>tr</td>
<td>tr</td>
<td>tr</td>
<td></td>
</tr>
<tr>
<td>Chlorite</td>
<td>tr</td>
<td>tr</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Plagioclase</td>
<td>tr</td>
<td>tr</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

M=major (>20%), m=minor (20%>m>5%), tr= trace (<5%)

2.2.2.2 Reactive Transport Modeling

2.2.2.2.1 Overview

The chemical interactions between host rocks and injection fluids, by causing the dissolution or precipitation of minerals, can either enhance or destroy permeability. Results of recent studies such as those of Durst (2002) and Bachler (2003) suggest that these chemical interactions can greatly impact the performance of EGS reservoirs over the long term. Reactive chemical transport simulation can therefore serve as a useful tool in managing injection strategies. To assess these interactions and their potential effects on the 46A-19RD stimulation experiment, modeling efforts using the program TOUGHREACT (Xu and Pruess, 2001; Xu et al., 2006) were initiated.

TOUGHREACT is a non-isothermal reactive geochemical transport code developed by T. Xu and K. Pruess at Lawrence Berkeley National Labs. Its physical and chemical process capabilities and solution techniques are outlined in Xu and Pruess (2001). This simulator can be applied to 1-, 2-, and 3-dimensional porous, fractured media. Physical and chemical properties can be homogeneous or heterogeneous, and solid, liquid, and gaseous phases of chemical species can be present.

A 1-D modeling study to simulate injection into East Flank well 34-9RD2 was completed. Using this model, changes in porosity and permeability, and precipitation/dissolution of calcite, amorphous silica, quartz, and other minerals in a simulated injection experiment was investigated. Results indicated that amorphous silica precipitation could significantly affect near-wellbore porosity. In future work, a similar modeling approach will be used to study injection into well 46A-19RD. Data from the petrologic and petrographic studies collected this year on well 46A-19RD will be incorporated into this model. Also, appropriate thermal and fluid compositional data from this part of the field will be used.

2.2.2.2.2 The 34-9RD2 1-D Model

Fluid and Heat Flow Conditions
The geometry and fluid and heat flow conditions were modeled after those described in Xu and Pruess (2004). A one-dimensional MINC (multiple interacting continua) model was used to represent the fractured rock. The MINC method can resolve “global” flow and diffusion of chemicals in the fractured rock and its interaction with “local” exchange between fractures and matrix. Details of the MINC method for reactive geochemical transport are described by Xu and Pruess (2001). Two different mineral zones were considered: 1) a zone representing the relatively impermeable, unaltered host rock, and 2) a zone representing the relatively fractured, altered veins. Various physical characteristics of the two different zones are shown in Table 2. Density = 2650 kg·m⁻³, heat capacity = 1000 J·kg⁻¹·K⁻¹, and diffusivity = 10⁻⁹ m²·s⁻¹ were used for both zones. The cubic law was used to define the porosity-permeability relationship in both zones (Xu et al., 2004). The model generates changes in porosity and permeability based on changes in mineral abundances.

Mineralogical Conditions
The host rock type chosen for the preliminary injection simulations was biotite granodiorite. This rock type dominates the deepest intervals of wells on the 34-9 pad (Figure 3 in Petrology Section). Granodiorite was also identified as a major rock type in the zone targeted for stimulation in well 46A-19RD. This is an intermediate rock type in terms of composition and alteration found in the East Flank wells. Estimates of the mineralogical composition of the granodiorite (in terms of volume percentage of solid rock) were made on the basis of X-ray diffraction data and petrographic observations (Kovac et al., 2005; Lutz and Moore, 1997). Mineralogically, the granodiorite consists of mostly quartz, plagioclase, and potassium feldspar with minor biotite (Table 3). In general, the granodiorite displays only weak alteration consisting of illitic clays and chlorite (Table 3).

Estimation of the fractured vein mineralogy was made using a more holistic approach based upon the average paragenetic sequence observed in the East Flank wells. Estimates of mineralogical composition in terms of volume percentage of solid rock were based on detailed petrographic observations and petrologic analysis of core and cuttings (Table 3; Kovac et al., 2005; Lutz and Moore, 1997). Porosity and permeability were assumed to be much greater in the fractured vein zone than in the granodiorite zone (Table 2). Initial rock temperature for both zones was 275°C in the preliminary simulations. Conductive heat exchange with the surrounding low-permeability rock is an important process, and is treated with a semi-analytical technique developed by Vinsome and Westerveld (1980).

Mineral Kinetic Rates and Parameters
Mineral dissolution and precipitation are considered under kinetic constraints. A general kinetic rate expression is used in TOUGHREACT (Xu et al., 2004):

\[ r_m = \pm k_m A_m a_{\text{H}^+}^n (1 - Q_m/K_m) \]  

(1)

where m is the mineral index, \( r_m \) is the dissolution/precipitation rate, (positive for dissolution, negative for precipitation), \( k_m \) is the rate constant (moles per unit mineral surface area and unit time) which is temperature-dependent, \( A_m \) is the specific reactive surface area per kg of H₂O, \( a_{\text{H}^+} \) is the activity of H⁺, and n is an empirical reaction order accounting for catalysis by H⁺ in solution. \( K_m \) is the equilibrium constant for the mineral-water reaction written for the destruction
of one mole of mineral $m$, $Q_m$ is the ion activity product. The temperature dependence of the reaction rate constant can be expressed as:

$$k = k_{25} \exp\left[-\frac{E_a}{R \left(1/T - 1/298.15\right)}\right]$$  \hspace{1cm} (2)

where $E_a$ is the activation energy, $k_{25}$ is the rate constant at $25^\circ C$, $R$ is the universal gas constant, and $T$ is absolute temperature. Table 4 shows the parameters used in the kinetic rate expression.

**Table 2.2-2. Hydrologic and thermal parameters for the two zones.**

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Fractured Vein</th>
<th>Weakly-Altered Granodiorite</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volume ($m^3$)</td>
<td>0.1</td>
<td>0.9</td>
</tr>
<tr>
<td>Permeability ($m^2$)</td>
<td>2.0E-12</td>
<td>2.0E-18</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.10</td>
<td>0.02</td>
</tr>
<tr>
<td>Thermal conductivity ($W \cdot m^{-1} \cdot K^{-1}$)</td>
<td>2.9</td>
<td>3.0</td>
</tr>
<tr>
<td>Tortuosity</td>
<td>0.3</td>
<td>0.1</td>
</tr>
</tbody>
</table>

**Table 2.2-3. Simplified initial mineralogical composition of the two zones used in the preliminary simulations.**

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Volume Percentage of Solid Rock</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Fractured Vein</td>
</tr>
<tr>
<td>Quartz</td>
<td>0.17</td>
</tr>
<tr>
<td>Potassium Feldspar</td>
<td></td>
</tr>
<tr>
<td>Chlorite</td>
<td>0.23</td>
</tr>
<tr>
<td>Illite</td>
<td>0.08</td>
</tr>
<tr>
<td>Smectite-Na</td>
<td>0.02</td>
</tr>
<tr>
<td>Smectite-Ca</td>
<td>0.06</td>
</tr>
<tr>
<td>Calcite</td>
<td>0.31</td>
</tr>
<tr>
<td>Anorthite</td>
<td></td>
</tr>
<tr>
<td>Annite</td>
<td></td>
</tr>
</tbody>
</table>

**Water Chemistry**

The composition of the reservoir fluid was estimated based on the approximate composition taken from an East Flank well (Table 5). Initial fluid compositions within the fractured vein and granodiorite zones were calculated by equilibrating the reservoir fluid composition with each zone’s mineralogical composition at $275^\circ C$. An example injection fluid composition that is
relatively high in concentrations of Na\textsuperscript{+}, Cl\textsuperscript{-}, and SiO\textsubscript{2}(aq) was chosen as the trial injection water (Table 5). The injectate composition was not allowed to change over time.

Table 2.2-4. List of kinetic rate parameters used in Eqs. (1) and (2) for minerals considered in the present paper (Xu and Pruess, 2004; Palandri and Kharaka 2004). The first line indicates dissolution parameters and the second line precipitation parameters; the same values were used for both where only one line is shown.

<table>
<thead>
<tr>
<th>Mineral</th>
<th>k\textsubscript{25} (moles m\textsuperscript{-2} s\textsuperscript{-1})</th>
<th>E\textsubscript{a} (KJ/mole)</th>
<th>n (rxn. order)</th>
<th>Surface Area (cm\textsuperscript{2}/g)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calcite</td>
<td>6.918E-2</td>
<td>18.98</td>
<td>1</td>
<td>9.8</td>
</tr>
<tr>
<td></td>
<td>6.456E-7</td>
<td>62.76</td>
<td>0</td>
<td>9.8</td>
</tr>
<tr>
<td>Quartz</td>
<td>1.26E-14</td>
<td>87.5</td>
<td>0</td>
<td>9.8</td>
</tr>
<tr>
<td>Am. Silica</td>
<td>7.32E-13</td>
<td>60.9</td>
<td>0</td>
<td>1.0E6</td>
</tr>
<tr>
<td></td>
<td>3.80E-10</td>
<td>49.8</td>
<td>0</td>
<td>1.0E6</td>
</tr>
<tr>
<td>K-feldspar</td>
<td>1.00E-12</td>
<td>57.78</td>
<td>0</td>
<td>9.8</td>
</tr>
<tr>
<td>Anorthite</td>
<td>1.00E-12</td>
<td>57.78</td>
<td>0</td>
<td>9.8</td>
</tr>
<tr>
<td>Na-smectite</td>
<td>1.00E-14</td>
<td>58.62</td>
<td>0</td>
<td>151.63</td>
</tr>
<tr>
<td>Ca-smectite</td>
<td>1.00E-14</td>
<td>58.62</td>
<td>0</td>
<td>151.63</td>
</tr>
<tr>
<td>Illite</td>
<td>1.00E-14</td>
<td>58.62</td>
<td>0</td>
<td>151.63</td>
</tr>
<tr>
<td>Annite</td>
<td>2.51E-15</td>
<td>66.20</td>
<td>1</td>
<td>9.8</td>
</tr>
<tr>
<td></td>
<td>2.51E-15</td>
<td>66.20</td>
<td>0</td>
<td>9.8</td>
</tr>
<tr>
<td>Dolomite</td>
<td>1.023E-3</td>
<td>20.90</td>
<td>1</td>
<td>9.8</td>
</tr>
<tr>
<td></td>
<td>4.47E-10</td>
<td>62.76</td>
<td>0</td>
<td>9.8</td>
</tr>
<tr>
<td>Chlorite</td>
<td>2.51E-12</td>
<td>62.76</td>
<td>0</td>
<td>151.63</td>
</tr>
<tr>
<td>Anhydrite</td>
<td>6.45E-4</td>
<td>14.3</td>
<td>0</td>
<td>9.8</td>
</tr>
</tbody>
</table>

Table 2.2-5. Example approximate composition of reservoir fluid from an East Flank well and injection fluid composition as used in the simulations.

<table>
<thead>
<tr>
<th>Chemical Component</th>
<th>Reservoir Fluid Mol/kg</th>
<th>Injection Fluid Mol/kg</th>
</tr>
</thead>
<tbody>
<tr>
<td>SiO\textsubscript{2}</td>
<td>0.013</td>
<td>.017</td>
</tr>
<tr>
<td>B(OH)\textsubscript{3}</td>
<td>8.42E-3</td>
<td>.012</td>
</tr>
<tr>
<td>Na\textsuperscript{+}</td>
<td>0.095</td>
<td>.12</td>
</tr>
<tr>
<td>K\textsuperscript{+}</td>
<td>0.012</td>
<td>.017</td>
</tr>
<tr>
<td>Li\textsuperscript{+}</td>
<td>2.45E-3</td>
<td>5.55E-3</td>
</tr>
<tr>
<td>Ca\textsuperscript{2+}</td>
<td>9.55E-4</td>
<td>1.05E-3</td>
</tr>
<tr>
<td>Mg\textsuperscript{2+}</td>
<td>4.12E-6</td>
<td></td>
</tr>
<tr>
<td>Sr\textsuperscript{2+}</td>
<td>3.6E-5</td>
<td></td>
</tr>
<tr>
<td>Cl\textsuperscript{-}</td>
<td>0.11</td>
<td>.14</td>
</tr>
<tr>
<td>F\textsuperscript{-}</td>
<td>1.47E-4</td>
<td>1.36E-4</td>
</tr>
</tbody>
</table>
Results
A one-dimensional MINC (multiple interacting continua) model was used. Our conceptual model considers a one-dimensional flow tube between the injection and production wells, which is a small sub-volume of the more extensive three-dimensional reservoir. The initial reservoir conditions were 275°C temperature and 30MPa pressure. An over-pressure of 2 MPa was applied to the injection side. The initial simulation was run for a total time of 10 years. Changes in fluid pH, fracture porosity, fracture permeability, fluid temperature, and changes in mineral abundances were monitored to a distance of 594 m from the injection well. Mineral abundance changes were reported in terms of changes in volume fraction for the following minerals: quartz, potassium feldspar, chlorite, illite, sodium smectite, calcium smectite, calcite, dolomite, anorthite, biotite, amorphous silica, and anhydrite. Calcite, quartz, and amorphous silica displayed the most significant changes. Changes in porosity were calculated as a function of mineral dissolution and precipitation. Porosity increase indicates that mineral dissolution is dominant, while porosity decreases when precipitation dominates. Changes in permeability are calculated from changes in porosity as described above.

Figure 21 plots porosity versus distance from the injection well at times of 1 day - 10 years after start of injection. Figure 22 displays amorphous silica precipitation versus distance at times of 1 day -10 years after initial injection. It is evident that near-wellbore porosity drops 60% shortly after injection (~1 day after injection), due to amorphous silica precipitation. This is in good agreement with field data on amorphous silica precipitation rates (Padilla et al., 2005; Alcober et al., 2005). Figure 23 shows that some quartz precipitation occurs, but that this is several orders of magnitude less significant than the amorphous silica precipitation. Also, the quartz precipitation does not occur as soon as the amorphous silica precipitation. These results are corroborated by field observations (McLin et al., 2006) that identified major amorphous silica and trace quartz in fractures post-injection. Calcite displays a small amount of dissolution near the wellbore (0-0.8m) over the 10 year period (Fig. 31); elsewhere, precipitation is dominant. Further out from the wellbore (~100- 600 m), porosity is maintained but has decreased approximately 20% after 10 years. Calcite is the mineral largely responsible for this gradual porosity loss. This is corroborated by observations from the field that calcite dominates the veins further away from the injection wellbore (McLin et al., 2006).

Temperature, chemical composition, and pH of injection fluid, host rock and fracture mineralogies can all have great impact on the fate of injection. These parameters will be examined more closely through sensitivity studies in future work. At this point, the relatively large amount of SiO2(aq) in the injection fluid appears to be a factor that could potentially have a significant impact on porosity and permeability.

<table>
<thead>
<tr>
<th></th>
<th>HCO3⁻</th>
<th>1.1E-3</th>
<th>1.25E-4</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO4²⁻</td>
<td>3.12E-4</td>
<td>7.06E-4</td>
<td></td>
</tr>
<tr>
<td>HS⁻</td>
<td>3.02E-5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CH₄</td>
<td>6.25E-10</td>
<td></td>
<td></td>
</tr>
<tr>
<td>pH</td>
<td>6.84</td>
<td>4.87</td>
<td></td>
</tr>
<tr>
<td>T (°C)</td>
<td>275</td>
<td>77</td>
<td></td>
</tr>
</tbody>
</table>
Figure 2.2-21. Porosity versus distance in meters (logarithmic scale) for the simulation

Figure 2.2-22. Amorphous silica precipitation versus distance from the injection well. Note that the distance shown is 0-2 meters from the injection point.
Figure 2.2-23. Quartz precipitation versus distance from the injection point. Note that the distance shown is 0-10 meters from the injection point.

Figure 2.2-24. Calcite precipitation and minor dissolution (negative values) versus distance for 0-100 m from the injection point.

Amorphous silica precipitation kinetics
Both the model and field experience suggest that under the conditions proposed for the hydrofracture experiment and injection, amorphous silica precipitation could be problematic. Amorphous silica is the mineral expected to precipitate most strongly near the injection well and therefore have the greatest impact on near-wellbore porosity and permeability. Several methods
have been proposed in the literature to quantify rates of amorphous silica precipitation. Here calculations are made using the data for Coso that compare these methods to those used by TOUGHREACT. Similar calculations are also made for quartz, although the kinetics are considered to be much more straightforward for quartz than for amorphous silica.

Amorphous silica precipitation kinetics are complicated and considered to be poorly constrained. It can precipitate through two different mechanisms: 1) molecular deposition and 2) colloidal deposition. Molecular deposition occurs when monomeric silica precipitates directly onto a solid silica surface. Colloidal deposition occurs when the solution is oversaturated in silica by a factor of ten or greater. In this case, the silica molecules polymerize and form a colloid that remains suspended in the fluid. After the colloidal particles reach a critical size, they then begin to precipitate.

Weres et al. (1982) developed a method for calculating molecular silica deposition. Their empirical method calculates deposition based on silica concentration, temperature, pH, and salinity. Table 6 shows input parameters from the East Flank used in making all calculations except Weres et al. (1982). Using Weres et al. (1982) graphical method (Figure 1 and Equations (9) and (10) in their paper), the rate of amorphous silica deposition was calculated at a pH = 7 to be 2.8E-7 mol*m^-2*sec^-1, and at the pH of injection (~5) to be 5.6E-9 mol*m^-2*sec^-1. Therefore, under acid conditions, the rate of deposition decreases by two orders of magnitude compared to neutral conditions.

Carroll et al. (1998) investigated amorphous silica precipitation under simple laboratory conditions, which was found to follow the equation:

\[ \text{Rate}_{\text{ppt}} = k_{\text{ppt}} \exp \left( -\frac{E_a}{RT} \right) \left( 1 - \exp \left( \frac{-\Delta G_r}{RT} \right) \right) \] (3)

and more complicated field observations, which followed the relationships

\[ \text{Rate}_{\text{ppt}} = 10^{-10.00\pm0.06} \left( \exp \left( \frac{\Delta G_r}{RT} \right) \right)^{4.4\pm0.3} \] (4),

or

\[ \text{Rate}_{\text{ppt}} = 10^{-9.29\pm0.03} \left( \frac{\Delta G_r}{RT} \right)^{1.7\pm0.1} \] (5).

Using the values for Coso yielded rates of 2.6E-11 [Si]m^-2*sec^-1 for the laboratory relationship and 3.1E-8 and 8.1E-10 for the field relationships. The field results are larger than the laboratory results. The authors attributed the difference in values to differing controls on laboratory setup versus field conditions. The dominant precipitation mechanism would be elementary reaction control in the laboratory, while in the more complicated field experiments it would be surface defect/nucleation control (Carroll et. al 1998).

Rimstidt and Barnes (1980) use a method based on transition state theory that is consistent with a thermodynamic approach. This approach is largely the one reactive geochemical programs are based upon, including TOUGHREACT. Using the equations of Rimstidt and Barnes a deposition rate of 1.5E-11 mol*m^-2*sec^-1 is obtained.
Using the equations employed in TOUGHREACT for amorphous silica precipitation (Xu et al., 2004):

\[ r = kA[\Omega^{0.1}/(\Omega^{2/3})] \]  

(6),

where

\[ k = k_{25} \exp[-E_a/R^* (1/T - 1/298.15)] \]  

(7),

and

\[ \Omega = Q/K \]  

(8)

This method yields a rate of 6.5E-7 mol*m\(^{-2}\)*sec\(^{-1}\).

In looking at the summary of all calculations (Table 7), it is apparent that the calculations made by TOUGHREACT compare well in general to field and empirical rates from the literature, and less well to the theoretical models.

**Table 2.2-6. A table of constants used to calculate rates of amorphous silica precipitation according to different methods from the literature.**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>T (K)</td>
<td>349.7</td>
<td>349.7</td>
<td>349.7</td>
</tr>
<tr>
<td>Area (m(^2))</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>(k_{25}) (mol m(^{-2})*sec(^{-1}))</td>
<td>1E-1.9</td>
<td>3.80E-10</td>
<td></td>
</tr>
<tr>
<td>(E_a) (kJ*mol(^{-1}))</td>
<td>61</td>
<td>49.8</td>
<td></td>
</tr>
<tr>
<td>H</td>
<td>1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(\Theta)</td>
<td></td>
<td>4.4</td>
<td></td>
</tr>
<tr>
<td>log(Q/K)</td>
<td>.5673</td>
<td>.5276</td>
<td></td>
</tr>
<tr>
<td>(\Omega)</td>
<td></td>
<td></td>
<td>3.72</td>
</tr>
<tr>
<td>(K_{eq}) from Gunnarsson and Arnorsson, 2000)</td>
<td>4.604E-3</td>
<td>4.604E-3</td>
<td></td>
</tr>
<tr>
<td>((A/M)_{kinetic})</td>
<td>10E4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Table 2.2-7. Summary of amorphous silica precipitation rate estimates using the data for Coso and methodology of the authors listed.

<table>
<thead>
<tr>
<th>Source</th>
<th>Amorphous silica precipitation rates (mol m⁻² sec⁻¹)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carroll et al. (1998)</td>
<td>2.6E⁻¹¹ (lab)</td>
</tr>
<tr>
<td></td>
<td>3.1E⁻⁸ (field)</td>
</tr>
<tr>
<td></td>
<td>8.1E⁻¹⁰ (field)</td>
</tr>
<tr>
<td>Weres et al. (1982)</td>
<td>5.6E⁻⁹ (@pH=5)</td>
</tr>
<tr>
<td></td>
<td>2.8E⁻⁷ (@pH=7)</td>
</tr>
<tr>
<td>Rimstidt &amp; Barnes (1980)</td>
<td>1.5E⁻¹¹</td>
</tr>
<tr>
<td>TOUGHREACT</td>
<td>6.5E⁻⁷</td>
</tr>
</tbody>
</table>

Quartz precipitation kinetics
Similar calculations were made for quartz, comparing values from the literature to those generated in TOUGHREACT. The kinetics of quartz precipitation is considered to be much more straightforward than that of amorphous silica. Constants for Coso used to make these calculations are shown in Table 8. The method of Rimstidt and Barnes (1980) as described above was used to generate an approximate precipitation rate of quartz of 2.2E⁻¹⁴ mol*m⁻²*sec⁻¹.

Dove (1994) uses a different approach to the problem. Here, the rate equation is based on a surface reaction model that relates changes in modeled surface complexes with quartz reactivity in aqueous solutions (Dove, 1994). According to Dove’s equation the precipitation rate can be found from the relation:

\[
\text{rate} = \exp^{-10.7T} \exp^{\left(-66000/RT\right)\theta_{\text{SiOH}}} + \exp^{4.7T} \exp^{\left(-82700/RT\right)\theta_{\text{SiO}^\text{-t}ot}}. \tag{9}
\]

Using this method, the rate of quartz precipitation is 3.3E⁻¹¹ mol*m⁻²*sec⁻¹.

The rate expression for quartz in TOUGHREACT is given in Eq. 1. Thus, it follows that the value calculated by TOUGHREACT is very similar to that of Rimstidt and Barnes (Table 9). These two values are significantly different that that of Dove (1994), which seems reasonable considering the approach is quite different.
Table 8. A table of constants used to calculate rates of quartz precipitation according to different methods from the literature.

<table>
<thead>
<tr>
<th></th>
<th>Rimstidt &amp; Barnes (1980)</th>
<th>TOUGHREACT</th>
</tr>
</thead>
<tbody>
<tr>
<td>T (K)</td>
<td>349.7</td>
<td>349.7</td>
</tr>
<tr>
<td>Area (m²)</td>
<td>1</td>
<td>.001</td>
</tr>
<tr>
<td>k₂₅ (mol m⁻² sec⁻¹)</td>
<td></td>
<td>1.2589E-14</td>
</tr>
<tr>
<td>Eₐ (kJ mol⁻¹)</td>
<td></td>
<td>87.5</td>
</tr>
<tr>
<td>H</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Θ</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>log(Q/K)</td>
<td>1.422</td>
<td>1.413155</td>
</tr>
<tr>
<td>Ω</td>
<td></td>
<td>25.9</td>
</tr>
<tr>
<td>K_eq (from Gunnarsson and Arnorsson, 2000)</td>
<td>.000644</td>
<td></td>
</tr>
<tr>
<td>(A/M)ₖinetic</td>
<td>10</td>
<td></td>
</tr>
</tbody>
</table>

Table 2.2-9. Summary of quartz precipitation rate estimates using the data for Coso and methodology of the authors listed.

<table>
<thead>
<tr>
<th>Source</th>
<th>Quartz precipitation rates (mol m² sec⁻¹)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rimstidt (1980)</td>
<td>2.2E-14</td>
</tr>
<tr>
<td>Dove (1994)</td>
<td>3.3E-11</td>
</tr>
<tr>
<td>TOUGHREACT</td>
<td>6.2E-14</td>
</tr>
</tbody>
</table>

Conclusions

Geologic, petrographic, temperature, and geochemical data collected on well 34-9RD2 were input into TOUGHREACT, creating an initial model of injection into a Coso East Flank well. This model generally agrees with post-injection observations from the field. Significant amorphous silica, and minor amounts of calcite, quartz, and anhydrite are shown to precipitate while only calcite shows dissolution in the fractures. Amorphous silica could reduce porosity and permeability in the vicinity of the injection well during enhancement, and this is corroborated by the initial model.

Amorphous silica kinetics, although very important to geothermal operations, is considered to be poorly constrained under geothermal conditions. Using the data for Coso, calculations were made from the literature for the rates of amorphous silica and quartz precipitation and these values were compared to those used by TOUGHREACT. In the case of quartz, values calculated by TOUGHREACT compare well to values calculated by Rimstidt and Barnes (1980), which follows as the TOUGHREACT method is derived from the Rimstidt and Barnes (1980) method. In the case of amorphous silica, the value calculated by TOUGHREACT is quite different than estimates calculated using Rimstidt and Barnes (1980) and other theoretical methods in the literature. However, it compares well to field and empirical rates from the literature.
2.2.2.2.3 The 46A-19RD 1-D Model

In future work, a similar modeling approach to that described above for well 34-9RD2 will be implemented for injection well 46A-19RD. Petrologic, petrographic, and mineralogic data collected on this well over the past year will be input into this model. At first, a one dimensional three layer minc (multiple interacting continua) modeling approach will be used. Based on the petrologic and petrographic studies, the three domains used in the minc model will be 1) the granodiorite host rock, 2) altered zone mineralogy, and 3) youngest vein mineralogy. Thermal and fluid chemistry data from this portion of the field will be inputted. Additionally, one dimensional radial modeling of the injection well simulating the chemical stimulation experiments using the approach of Xu et al. (2004) will be further investigated.

2.2.2.2.4 References


2.3 Microseismics (Frank Monastero, Gillian Foulger and Bruce Julian)

2.3.1 Background and Objectives

The purpose of this project is to improve our understanding of fracture systems and geothermal fluids at the Coso geothermal area and how they change in response to geothermal operations and hydraulic fracturing experiments conducted to produce an Engineered Geothermal System (EGS). To do this, we apply modern seismological methods to determine complete earthquake mechanisms, high-resolution hypocenter locations, and four-dimensional (time-varying three-dimensional) structure. The information to be gathered bears directly on:

- Fracture geometry (locations, dimensions, orientations, growth)
- Fracture type (shear faults vs. mode-I cracks; creation vs. reactivation)
- Stress and strain
- Host-rock porosity
- Fluid migration
- Pore-fluid state

In addition to applying state-of-the-art existing data analysis techniques to data collected on the U.S. Navy permanent seismometer network, major aspects of the work have been:

- development of advanced software for monitoring microearthquakes on a continuing basis,
- the integration of this software into the existing system that monitors seismicity at Coso,
- development of interface software so the techniques can be applied on a routine basis, and
- installing and operating densification networks to improve monitoring of specific, local EGS experiments.

2.3.2 Milestones for 2007

- Visit China Lake, organize computer networking 2007 February
- Monitor 46A-19RD stimulation 2007 April-May
- Download portable-instrument data, re-format Navy data. 2007 May-June
- Compute high-resolution hypocenters 2007 June-?:
• Determine moment-tensor focal mechanisms 2007 July-Sept.
• Interpret hypocenters, moment tensors. Prepare for publication. 2007 Sept.

2.3.3 Accomplishments 2003-2006

2.3.3.1 Microearthquake Monitoring

1.1 Permanent U.S. Navy Seismometer Network

Sensor Orientations

Determining earthquake mechanisms from seismic wave polarities and amplitude ratios requires data from three-component seismometers of known orientation. Unfortunately, the orientations of the permanent horizontal-component borehole seismometers at Coso initially were not well known. It is possible to estimate these orientations, however, by analyzing seismograms of $P$ phases from local earthquakes. These are longitudinal waves, so their particle motion is in the ray directions, which can be predicted if the earthquake locations and the local structure are known. The particle-motion direction with respect to a sensor can be determined directly from multi-component seismograms, enabling the orientation of the sensor to be inferred.

In collaboration with personnel from the U.S. Navy, we used this method to determine the orientations of seismometers of the permanent network. Figure 1.1 shows an example result, for station NV2.

![Station NV2](image)
Figure 1.1: An example of determining seismometer orientation from P-phase amplitude measurements. Each circle shows the sensor orientation (azimuth of the “north” component) inferred from measurements from one earthquake, and the abscissa gives the earthquake-to-sensor azimuth. The data for waves coming from many directions lead to consistent inferred sensor orientations. A small systematic dependence on wave-propagation direction is caused primarily by local three-dimensional structure, not accounted for in this analysis.

This work led to the recognition that several sensors are wired incorrectly. Figure 1.2, for example, shows inferred sensor orientations for station NV5, which have extreme and systematic variations with the direction to the earthquake. Figure 1.3 shows the same data, analyzed under the assumption that the two horizontal components are interchanged. (Equivalently, one of the horizontal sensors could have its polarity reversed.) We have now entered information on sensor orientation and wiring as functions of time into a database, and corrections for these errors are made automatically during seismogram analysis. The detailed results are discussed in Section 4 (below).

Figure 1.2: Same as Figure 1.1, but for a sensor that is wired incorrectly. The inferred sensor orientation varies strongly and systematically with the direction to the earthquake. This variation is expected if one horizontal component has a reversed polarity, or equivalently if the two horizontal components are interchanged. See Figure 1.3.
Real-Time Monitoring

To be most useful in monitoring an EGS experiment, processed seismological information (hypocenter locations and source mechanisms) should be available in near-real time. Currently, however, site visits are needed to collect data from the portable seismometer network at Coso, so processed data from these stations are available only after a delay of several days. Data from the permanent U.S. Navy seismometers are telemetered to China Lake in real time, but the software in use there requires human interaction in the earthquake location process, which imposes a delay in the availability of the results.

To reduce these delays, we implemented an “EarthWorm” system for real-time automatic processing of telemetered data during injection experiments. EarthWorm (http://folkworm.ceri.memphis.edu/ew-doc/) is a hardware/software facility developed by the USGS over the last 15 years and is widely used in many seismic networks throughout the world. EarthWorm automatically detects events in real time, saves digital waveforms, picks P-phase arrival times, and computes earthquake locations using conventional methods. A companion software facility, EarlyBird, maintains a data base of derived data, including earthquake catalogs, provides interactive tools for rapidly searching and accessing the data, and automatically generates alarms to notify key personnel of significant earthquakes and swarms.

Since June 2006, computer security measures instituted by the Navy have made it impossible to access computers at China Lake, including the EarthWorm system, from outside the military base. We are still able to obtain seismic data by means of CDs prepared and mailed to us by

Figure 1.3: Same as Figure 1.2, but assuming that the horizontal components are interchanged. Inferred sensor orientations are now consistent.
Navy Personnel, and expect to replace this mechanism soon with one using Internet-based file transfer protocol (ftp). In early 2007 we will visit China Lake to make arrangements for computer and data access during the stimulation of well 46A-19RD, planned for Spring 2007. We anticipate that these arrangements will require our physical presence at China Lake during the 46A-19RD stimulation.

1.2 Portable Networks

Determining full moment-tensor microearthquake mechanisms requires data from seismograms well distributed over the upper focal hemisphere (well distributed around the earthquakes). For earthquakes in the Coso southwest and east flank areas however, the U.S. Navy’s permanent seismometer network provides good coverage for only part of the upper hemisphere. In order to monitor the EGS experiment at wells in these areas, we collaborated with the U.S. Navy in deploying portable seismometers to supplement the permanent network to the east of the geothermal field.

Designing a geometrically optimal network requires knowledge of how the earthquake focal sphere is mapped onto the Earth’s surface by seismic rays. In designing the portable networks, we computed this mapping by numerically tracing seismic rays through three-dimensional models of upper-crustal structure of the Coso area, assuming that the earthquakes induced by the planned EGS experiments occur near the bottoms of the wells stimulated. We used the results to choose optimal seismometer locations.

We designed two different networks. The first, operated in 2004 and 2005, focused on the east flank area, to monitor earthquakes near well 34-9RD2. The second is focused on well 46A-19RD, in the southwest part of the field, and was installed in early 2006.

East-Flank Deployment (Well 34-9RD2)

Figure 1.4 shows an example of mapping of the upper focal hemisphere onto the Earth’s surface for earthquakes in the east flank area at Coso. For a one-dimensional crustal model (i.e., wave-speed varying with depth only), the closed curves would comprise concentric circles and the radiating lines would be straight. The distortion of these circles and lines seen in Figure 1.4 results from refraction of the seismic waves by three-dimensional heterogeneities in the crust, and is analogous to the distortion of an image produced by light transmitted through a distorted lens.
Figure 1.4: Map showing the upper focal sphere of an earthquake, as projected onto the Earth's surface along seismic rays computed using a three-dimensional crustal model for Coso (Wu and Lees, 1999). The earthquake in this example is located 3 km below the surface at well 34-9RD2. The outward-radiating curves are lines of constant take-off azimuth on the focal sphere, spaced 30° apart. The closed curves are lines of constant “incidence angle” i, measured from nadir, spaced 10° apart. Horizontally departing rays (i = 90°) extend off the map to the west and northeast. The small-scale complexity of the pattern for rays departing toward the south and southeast reflects the sensitivity of ray paths to structural details in the model, which are imperfectly known. Similarly, the simplicity of the pattern for rays to the northwest reflects a lack of structural information for that area in the model.

We used information like that shown in Figure 1.4 to choose optimal portable-seismometer locations. Figure 1.5 shows both networks, permanent and portable, that monitored the March 2005 EGS experiment at the east flank. Table I gives the sensor coordinates.
Figure 1.5: Seismometers at the Coso geothermal area at the end of 2005. Red lines: borehole traces; green squares: permanent seismometers of the Navy network; yellow triangles (B01, B02, B3-B5 and C1-C10): temporary portable seismometers deployed to improve coverage of earthquakes near well 34-9RD2. The U.S. Navy stations and portable stations B01 and B02 were continuously telemetered to China Lake. In some cases, portable instruments were moved to quieter sites; at most 16 portable sites were occupied at any one time. Data from two portable sites (B01 and B02) were telemetered to China Lake in real time. Data from other sites were recorded on computer disks deployed in the field and downloaded periodically.
<table>
<thead>
<tr>
<th>Code</th>
<th>Latitude</th>
<th>Longitude</th>
<th>Elevation (m)</th>
<th>Type†</th>
<th>Telemetry</th>
</tr>
</thead>
<tbody>
<tr>
<td>B01</td>
<td>36:02:34.36</td>
<td>-117:46:55.62</td>
<td>1161</td>
<td>T</td>
<td>Y</td>
</tr>
<tr>
<td>B02</td>
<td>36:02:30.65</td>
<td>-117:45:42.22</td>
<td>1091</td>
<td>T</td>
<td>Y</td>
</tr>
<tr>
<td>B3</td>
<td>36:01:39.15</td>
<td>-117:44:56.18</td>
<td>1068</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>B4</td>
<td>36:00:45.71</td>
<td>-117:46:16.19</td>
<td>1101</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>B5</td>
<td>36:01:42.07</td>
<td>-117:47:14.68</td>
<td>1220</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C1</td>
<td>36:04:00.16</td>
<td>-117:47:32.07</td>
<td>1550</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C10</td>
<td>36:02:53.43</td>
<td>-117:48:31.46</td>
<td>1337</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C2</td>
<td>36:03:56.24</td>
<td>-117:45:37.87</td>
<td>1157</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C3</td>
<td>36:03:37.95</td>
<td>-117:44:34.03</td>
<td>1149</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C4</td>
<td>36:02:22.47</td>
<td>-117:43:42.32</td>
<td>1267</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C5</td>
<td>36:01:20.27</td>
<td>-117:43:55.77</td>
<td>1213</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C6</td>
<td>35:59:33.76</td>
<td>-117:46:02.69</td>
<td>966</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C7</td>
<td>36:00:25.17</td>
<td>-117:47:24.48</td>
<td>1249</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C8</td>
<td>36:01:34.34</td>
<td>-117:48:34.51</td>
<td>1424</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>C9</td>
<td>36:02:49.18</td>
<td>-117:48:24.00</td>
<td>1330</td>
<td>T</td>
<td>N</td>
</tr>
<tr>
<td>CE1</td>
<td>36:00:47.16</td>
<td>-117:48:09.00</td>
<td>1194</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>CE2</td>
<td>36:02:01.32</td>
<td>-117:47:17.88</td>
<td>1244</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>CE3</td>
<td>36:00:52.20</td>
<td>-117:49:11.28</td>
<td>1260</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>CE4</td>
<td>35:59:59.28</td>
<td>-117:48:08.28</td>
<td>1316</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>CE5</td>
<td>36:00:29.52</td>
<td>-117:45:51.12</td>
<td>1035</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>CE6</td>
<td>36:02:01.19</td>
<td>-117:46:21.81</td>
<td>1130</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>CE7</td>
<td>36:03:01.80</td>
<td>-117:48:16.56</td>
<td>1240</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>CE8</td>
<td>36:03:04.32</td>
<td>-117:50:19.32</td>
<td>1200</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NS10</td>
<td>35:59:56.60</td>
<td>-117:44:42.70</td>
<td>1060</td>
<td>T</td>
<td>Y</td>
</tr>
<tr>
<td>NS5</td>
<td>36:05:02.04</td>
<td>-117:45:12.96</td>
<td>1170</td>
<td>T</td>
<td>Y</td>
</tr>
<tr>
<td>NV1</td>
<td>35:58:57.72</td>
<td>-117:45:53.64</td>
<td>776</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NV10</td>
<td>35:59:56.60</td>
<td>-117:44:42.70</td>
<td>960</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NV2</td>
<td>36:01:31.80</td>
<td>-117:37:16.68</td>
<td>1551</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NV3</td>
<td>36:08:29.04</td>
<td>-117:41:15.36</td>
<td>1947</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NV4</td>
<td>36:02:51.72</td>
<td>-117:44:25.08</td>
<td>1103</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NV5</td>
<td>36:05:02.04</td>
<td>-117:45:12.96</td>
<td>1070</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NV6</td>
<td>35:58:56.28</td>
<td>-117:48:27.36</td>
<td>1439</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>NV9</td>
<td>36:00:27.36</td>
<td>-117:45:05.40</td>
<td>1070</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>W1S</td>
<td>36:03:05.76</td>
<td>-117:59:44.52</td>
<td>1224</td>
<td>P</td>
<td>Y</td>
</tr>
<tr>
<td>W2S</td>
<td>36:06:59.04</td>
<td>-118:00:11.16</td>
<td>1336</td>
<td>P</td>
<td>Y</td>
</tr>
</tbody>
</table>

† T: Temporary; P: Permanent
Southwest Deployment (Well 46A-19RD)

During the spring of 2007, an EGS hydraulic-stimulation experiment will take place at well 46A-19RD, in the southwestern part of the Coso field. This well is on the periphery of the permanent and east-flank networks, and furthermore is significantly deeper than the east-flank wells, so redeploying several of the portable seismometers was necessary. In choosing new locations, we followed the same procedure described above, and traced rays through a three-dimensional crustal model to determine the best locations for additional, temporary stations. For this exercise, we were able to use a better crustal model, which we had derived as part of the tomography module of our work (see Section 3). Figure 1.6 shows the planned layout of the new network.

![Figure 1.6: Layout of seismometers to monitor earthquakes near well 46A-19RD, shown in blue. Red lines: roads. Green squares: permanent seismometers of the U.S. Navy network. Yellow triangles: portable seismometers that have been retained. Red triangle: re-deployed portable seismometers. Black lines: Upper focal hemisphere for microearthquakes near the bottom of well 46A-19RD, as mapped onto the Earth’s surface by seismic rays. Theoretical rays computed from our three-dimensional tomographic model are spaced by 10° in “take-off angle” (measured from nadir) and 30° in azimuth.](image)
2.3.3.2 Microearthquake Hypocenter Location

Although complete moment-tensor microearthquake mechanisms provide far more information than traditional fault-plane solutions do, including information about volume changes, that is important in geothermal monitoring, like fault-plane solutions, moment tensors are ambiguous and cannot uniquely identify the physical processes involved in earthquakes. It is thus critical to supplement moment tensors with additional information that can help in diagnosing these physical processes. Microearthquake hypocenter locations, if they are measured with high accuracy, can provide spatial images of seismic failure zones that are valuable for this purpose.

Traditionally, earthquakes are located individually, by fitting the arrival times of seismic waves of an earthquake at many seismometers. This method is subject to strong bias caused by wave-propagation effects in the incompletely known three-dimensional structure in the Earth. Recently developed methods greatly reduce this bias by fitting arrival-time differences and locating earthquakes relative to one another. Such methods yield accurate relative locations of nearby earthquakes, though they do not substantially improve absolute locations. A further substantial improvement, made by Waldhauser and Ellsworth (2000) involves simultaneously locating many (up to thousands) of earthquakes simultaneously, and greatly reduces the effects of random observational errors. Application of this method at other geothermal areas has demonstrated its usefulness in resolving seismically active geological structures, for example enabling us to distinguish tensile faults from shear faults at the Long Valley caldera, California, geothermal system (Foulger and others, 2004).

Figure 2.1 shows preliminary results of applying both kinds of methods to microearthquakes at Coso, using data from the permanent seismometer network recorded during injection experiments at well 51B-16 in September 2003. The Waldhauser-Ellsworth locations resolve microearthquake clusters near the injection well, as well as small northeast-southwest features in the general seismicity. The resolution is much better than single-event locations provide.
Figure 2.1: Comparison of conventional (above) and high-resolution (below) earthquake epicenters at Coso for September 2003, based on hand-measured times from the permanent U.S. Navy seismometer network. The high-resolution locations are more tightly clustered and resolve better northeast-southwest trends.
The existing implementation of the Waldhauser-Ellsworth method, the computer program hypoDD, can locate a large number of earthquakes simultaneously (up to about 10,000 on current computers), but suffers from several limitations:

- Limited speed and capacity
- Excessive memory requirements
- Inability to add earthquakes without re-processing the entire catalog
- Inability to improve the locations of diffuse earthquakes

A major effort of this project has been optimizing this algorithm and adapting it for studies of highly active areas such as Coso. The modified program, hypocc, is significantly faster and more flexible, and its earthquake-handling capacity is increased by an order of magnitude. The major improvements in hypocc over hypoDD include:

- Use of true station elevations. hypoDD (and most other hypocenter-location programs) assume all stations have the same elevation, biasing computed results and making the utilization of data from deep borehole instruments impossible.
- Use of modern algorithms, including hash tables and kD trees for rapidly searching station tables and earthquake catalogs.
- Representing event graphs with adjacency lists instead of adjacency matrices, effecting large memory savings because these graphs are sparse (typically only about 0.2% of possible links exist).
- Searching event graphs using depth-first-search (DFS) algorithms, which are thousands of times faster than sequential searching.
- Much more efficient storage of the (very sparse) condition-equation matrices, making feasible the analysis of much larger data sets.
- Efficient distance-azimuth calculations using geocentric direction cosines, avoiding most evaluations of trigonometric functions.
- Optimized seismic ray travel-time algorithms.

We will use hypocc to locate microearthquakes during the stimulation of well 46A-19RD at Coso in 2007. The hypocenters displayed on the web site http://cosomeq.wr.usgs.gov were computed using hypocc.

Although the Waldhauser-Ellsworth method can analyze hand-measured arrival times like those found in conventional earthquake catalogs, it performs best with relative arrival times measured by cross-correlating digital seismograms. The cross-correlation method uses the shapes of entire seismic waveforms, whereas hand-measured times use only their initial portions, which are of low amplitude and subject to large measurement errors. During 2004, we wrote software to make measurements of this kind using data from both the permanent and temporary Coso seismometer networks. Figure 2.2 shows results from applying this software to seismograms from the August 2004 injection experiment, and clearly illustrates its superiority over hand measurement.
Figure 2.2: Examples of measuring relative arrival times of seismic waves by cross-correlating digital seismograms. These vertical-component seismograms show P phases (the first-arriving waves) observed at portable station B01 from eleven earthquakes that occurred on 7 August 2004 near well 34A-9 during injection tests. The seismograms on the left are aligned by arrival times determined visually by a human analyst. On the right, the same seismograms are aligned using relative arrival times measured by waveform cross-correlation. The vertical lines are positioned arbitrarily and are provided as visual aids. The visually determined times (left) are based on the small high-frequency initial disturbances, which are highly variable from event to event and are sensitive to noise contamination. The cross-correlation times (right), in contrast, use the shape of the entire signal, and are more accurate and reliable. The improvement in alignment is obvious, for example between the third and fourth traces and between the bottom two traces. Each trace is about 0.26 seconds long, and consists of 0.13 seconds of signal plus about 0.13 seconds of zero padding. Relocation of the earthquakes using the arrival times determined using computer cross-correlation will reduce the relative location errors from 100s to 10s of meters.

2.3.3.3 Time-Dependent Seismic Tomography

3.1 Acquisition and Selection of Initial Data

Earthquake location catalog files and arrival time measurement files for each year 1992 – 2004 inclusive were downloaded from the U.S. Navy database over the Internet. The earthquake location catalog files contain, for each earthquake, the calculated time of occurrence, latitude, longitude, depth below the surface, root-mean-square (RMS) arrival time residual, azimuthal gap, number of P- and S-phase arrival time measurements used in the location, and auxiliary
Data. There is one arrival-time measurement file for each earthquake. These files contain the measured arrival-times of $P$- and $S$-phases at each station at which the earthquake was recorded well, along with codes that indicate the analyst-judged quality of each measurement.

Data for the years 1992 - 1995 suffered from various problems, including poor location quality as a result of early, lesser quality of the seismic network, and complexities in the data archive. As a result, we concentrated on the data from years 1996 - 2004. The seismic stations at the Coso geothermal area were located by U.S. Navy personnel using DGPS (differential GPS) and the locations are accurate to a few tens of meters. These station locations were provided by Dr. Keith Richards-Dinger at the U.S. Navy.

The earthquakes are clustered in the center of the network, which is also the most intensely exploited part of the geothermal area. The total annual numbers of earthquakes in the U.S. Navy catalogs are given in Table II.

Table II – Total Numbers of Earthquakes in each Year in U.S. Navy Catalog

<table>
<thead>
<tr>
<th>Year</th>
<th>Number of earthquakes</th>
</tr>
</thead>
<tbody>
<tr>
<td>1992</td>
<td>4,896</td>
</tr>
<tr>
<td>1993</td>
<td>5,461</td>
</tr>
<tr>
<td>1994</td>
<td>3,570</td>
</tr>
<tr>
<td>1995</td>
<td>4,500</td>
</tr>
<tr>
<td>1996</td>
<td>5,606</td>
</tr>
<tr>
<td>1997</td>
<td>4,003</td>
</tr>
<tr>
<td>1998</td>
<td>6,651</td>
</tr>
<tr>
<td>1999</td>
<td>8,439</td>
</tr>
<tr>
<td>2000</td>
<td>9,947</td>
</tr>
<tr>
<td>2001</td>
<td>5,140</td>
</tr>
<tr>
<td>2002</td>
<td>6,504</td>
</tr>
<tr>
<td>2003</td>
<td>5,025</td>
</tr>
<tr>
<td>2004</td>
<td>12,653</td>
</tr>
</tbody>
</table>

The entire earthquake data set contains many poorly recorded events that degrade data quality. A subset of the best events, which are suitable for tomographic inversions, was thus selected. Several different quality measures were used in this selection process, including the number of arrival times, root-mean-square arrival time and azimuthal gap. The numbers of earthquakes that passed these quality control tests are shown in Table III, and the distribution of epicenters for the six years 1998 - 2003 are shown in Figure 3.1.
Table III – Numbers of Earthquakes that Passed Quality-Control Tests

<table>
<thead>
<tr>
<th>Year</th>
<th>Number of earthquakes</th>
</tr>
</thead>
<tbody>
<tr>
<td>1992</td>
<td>881</td>
</tr>
<tr>
<td>1993</td>
<td>610</td>
</tr>
<tr>
<td>1994</td>
<td>1,489</td>
</tr>
<tr>
<td>1995</td>
<td>2,220</td>
</tr>
<tr>
<td>1996</td>
<td>1,904</td>
</tr>
<tr>
<td>1997</td>
<td>1,427</td>
</tr>
<tr>
<td>1998</td>
<td>2,277</td>
</tr>
<tr>
<td>1999</td>
<td>4,350</td>
</tr>
<tr>
<td>2000</td>
<td>4,368</td>
</tr>
<tr>
<td>2001</td>
<td>575</td>
</tr>
<tr>
<td>2002</td>
<td>1,894</td>
</tr>
<tr>
<td>2003</td>
<td>1,500</td>
</tr>
<tr>
<td>2004</td>
<td>6,127</td>
</tr>
</tbody>
</table>
Figure 3.1 Map of the Coso geothermal area showing locations of all earthquakes from the U.S. Navy earthquake location catalog files that occurred in the years 1998 – 2003 and passed the quality control tests. Seismic stations (green triangles) are also shown.
Additional filters were applied to winnow the data sets to optimize their suitability for tomographic inversion. For inversions for areas on the scale of the Coso geothermal area, a suitable number of earthquakes is a few hundred. This keeps program run times down to a practical level (less than ~1 hour per run) while yielding good structural resolution. We thus extracted from the sets of earthquakes that passed the quality control test, candidate subsets of a few hundred for each year that were well distributed throughout the target volume.

Earthquakes that were well outside the study area were rejected since long portions of the ray paths of such events lie outside the modeled volume. If they are included, structure outside of the volume of interest may be projected into the final inversion result. The area within which earthquakes were selected extended to an additional 2 km outside the main study area, this being both acceptable for the final three-dimensional tomography inversions and desirable in the case of this project, where many high-quality earthquakes lay just outside the geothermal area. The whole area was then subdivided into 196 squares, each 1 x 1 km in area. If a square contained fewer than 10 earthquakes, they were all selected, but if a square contained more than 10 earthquakes, they were ranked according to quality and the best 10 only were used.

3.2 Inversion for Best One-Dimensional Structure

The program *velest* (v3.3) (Kissling and others, 1994) inverts earthquake travel-time data for a model parameterized as a stack of homogeneous layers. It is useful both in its own right and it provides the best *a priori* starting model for three-dimensional tomography.

As a starting model for *velest*, a crustal model calculated by E. Shalev (Sondi & consultants; Shalev, 1994) was used. That model extends only to a depth of 2 km b.s.l., which is inadequate for the present work since the seismically active depth range may extend as deep as ~8 km b.s.l. It was thus extrapolated downward, yielding velocities similar to those currently used by the U.S. Navy for their routine earthquake location work.

Many inversions were performed using *velest* in order to explore parameter space and converge on the global minimum in the data. The integrity of the data was re-examined at various stages to eliminate outliers. Final inversions both with and without station corrections were performed for each of the 7 years 1997 – 2003 separately. The final RMS arrival-time residuals were in the range 0.031 - 0.048 s for inversions with station corrections, and 0.048 - 0.069 s for inversions without station corrections. This is to be expected, since the inversions with station corrections involved 49 free parameters compared with only 20 in the case of inversions without station corrections. The final numbers of earthquakes used for each year are given in Table IV.
Table IV – Numbers of Earthquakes Used for Final *velest* Inversions

<table>
<thead>
<tr>
<th>Year</th>
<th>#eqs</th>
</tr>
</thead>
<tbody>
<tr>
<td>1997</td>
<td>504</td>
</tr>
<tr>
<td>1998</td>
<td>648</td>
</tr>
<tr>
<td>1999</td>
<td>742</td>
</tr>
<tr>
<td>2000</td>
<td>724</td>
</tr>
<tr>
<td>2001</td>
<td>735</td>
</tr>
<tr>
<td>2002</td>
<td>691</td>
</tr>
<tr>
<td>2003</td>
<td>801</td>
</tr>
</tbody>
</table>

The final results for $V_P$, $V_S$ and $V_P/V_S$ are shown graphically in Figures 3.2a,b,c. Most of the final models are similar. Final $V_P$ and $V_S$ models (from which $V_P/V_S$ models were calculated) were obtained by fitting smooth profiles to the bundles of models in the suites of final inversions, ignoring the result for $V_P$ from 2001 without station corrections which was somewhat different from the others for reasons not well understood. The final models are shown by red triangles in Figures 3.2a,b,c and numerically in Table V.
Figure 3.2aCrustal structure results from final velest inversions; Vp. “w/ STs” signifies with station corrections, “w/o STs” signifies without stations corrections. Green triangles indicate the updated starting model obtained from preliminary inversions and the red triangles indicate the final one-dimensional model estimated by averaging by eye the results of the individual inversions. Note that there is a 1.5-km offset in depth, which was required to overcome technical restrictions in velest.
Figure 3.2b As Figure 3.2a but for $V_s$. 

Coso velest $V_s$ models

$V_s$ km/s

Depth km

-1.0
1.0
2.000
2.500
3.000
3.500
4.000

2000 w/ STs
2001 w/ STs
2002 w/ STs
2003 w/ STs
1997 w/ STs
1998 w/ STs
1999 w/ STs
2000 w/o STs
2001 w/o STs
2002 w/o STs
2003 w/o STs
1997 w/o STs
1998 w/o STs
1999 w/o STs
Updated starting model
Final 1D model
Figure 3.2c As Figure 3.2a but for $V_p/V_s$. 
Table V shows the final, numerical one-dimensional structural results, corrected for the temporary 1.5-km shift that was used during the calculations.

### Table V – Final Velocity Model with 1.5-km Shift Removed

<table>
<thead>
<tr>
<th>Depth to top of layer, km b.s.l.</th>
<th>$V_P$</th>
<th>$V_S$</th>
<th>$V_P/V_S$</th>
</tr>
</thead>
<tbody>
<tr>
<td>-2.0</td>
<td>4.35</td>
<td>2.51</td>
<td>1.733</td>
</tr>
<tr>
<td>-1.5</td>
<td>4.55</td>
<td>2.56</td>
<td>1.777</td>
</tr>
<tr>
<td>-1.0</td>
<td>4.95</td>
<td>2.78</td>
<td>1.781</td>
</tr>
<tr>
<td>0.0</td>
<td>5.37</td>
<td>3.05</td>
<td>1.761</td>
</tr>
<tr>
<td>1.0</td>
<td>5.71</td>
<td>3.29</td>
<td>1.736</td>
</tr>
<tr>
<td>2.0</td>
<td>5.76</td>
<td>3.36</td>
<td>1.714</td>
</tr>
<tr>
<td>3.0</td>
<td>5.81</td>
<td>3.42</td>
<td>1.699</td>
</tr>
<tr>
<td>4.0</td>
<td>5.82</td>
<td>3.49</td>
<td>1.668</td>
</tr>
<tr>
<td>6.0</td>
<td>5.82</td>
<td>3.49</td>
<td>1.668</td>
</tr>
<tr>
<td>8.0</td>
<td>5.82</td>
<td>3.49</td>
<td>1.668</td>
</tr>
</tbody>
</table>

Wave speeds determined for $V_P$ for the upper 2 km were slightly (as much as 0.12 km/s) lower than those obtained by Shalev et al. (1994) and currently used by the U.S. Navy for routine locations. Beneath this, the wave speeds obtained were substantially (up to 0.24 km/s) higher. A similar result was obtained for $V_S$. A typical crustal value for $V_P/V_S$ is 1.74. The average value obtained for the Coso area is 1.70. Beneath the shallowest level $V_P/V_S$ increases to a maximum of 1.78.

The top ~ 2 km of the producing reservoir is characterized by $V_P/V_S$ higher than 1.74. Beneath sea level an inversion occurs and values as low as 1.67 occur in the deepest levels sampled, which are at 4 – 8 km b.s.l. It is not clear what the geological significance of this is. It is most likely related to petrology since most geothermal processes of the kind likely to be occurring at Coso e.g., increase in steam content in pore fluids, are expected to decrease $V_P/V_S$.

### 3.3 Inversion for Best Three-Dimensional Structure

The area chosen for imaging is a north-orientated square, 10 km on a side, with its northwest corner at 36°N04.10706’, 117°W50.65611’ and its southeast corner at 35°N58.70000’, 117°W44.00000’ (Figure 3.3). This area is 100 km$^2$ in size and includes 13 of the 18 seismic stations of the U.S. Navy permanent network.

The program simul2000A (Thurber, 1983; Evans and others, 1994) was used to invert the data. This program uses a scheme where the compressional- and shear-wave speeds, $V_P$ and $V_S$, are parameterized by their values at nodes located at the intersections of orthogonal planes spaced at intervals of 2 km (or 1 km) horizontally and 1 km vertically. Nodes extend from 2 km above sea level (a.s.l.) to 10 km b.s.l. In this report we show structure only from 1 km a.s.l down to 4 km b.s.l. where the wave speeds are well determined. simul2000A uses an iterative, damped-least-
squares method to invert arrival times, simultaneously estimating earthquake locations and the three-dimensional $V_p$ and $V_p/V_S$ fields.

Data from years 1996 - 2004 were inverted. 1996 was the earliest year for which the seismic network, data collection and processing system at the U.S. Navy base at China Lake were stable and data throughout the year may be assumed to be of uniform quality and in a uniform format.

Figure 3.3  Map showing the square grid that encloses the area selected for the three-dimensional tomographic inversion. Red lines indicate the surface traces of geothermal boreholes, and green triangles indicate seismic stations.
Standard practice was in general followed. This involved starting with the one-dimensional model determined using *velest* and inverting the data on a grid with 2-km nodal spacings. The resulting 3-dimensional structure was interpolated to 1-km nodal spacings, and this model was used as a starting model to re-invert the data on a grid with 1-km nodal spacings. Damping values were chosen on the basis of “damping trade-off curves” (Evans and Achauer, 1993). In order to construct these, suites of one-iteration “damping” inversions were conducted with damping values set successively at 999, 100, 50, 20, 10, 5, 2, 1 and 0.1. Curves of data variance: model variance (“damping trade-off curves”) were then constructed for the inversion suite. The optimal damping value was the one that gave the largest data variance reduction. This method was used to select both $V_P$ and $V_P/V_S$ damping values. A detailed description of the inversion procedure is given in Foulger & Julian (2006). The entire tomography work module involved performing some 500 inversions.

In order to obtain the best possible average three-dimensional structural model for the entire time period studied here (1996 - 2004) a large number of earthquake arrival times drawn from years 1997 - 2003 were combined in a data set named “AllData”. The data set comprised 4811 earthquakes, and a total of 79,822 $P$ and $S$ travel times. In order to study changes in structure from year to year, that might be cause by production, independent inversions were also conducted for each of the years 1996 – 2004 separately. The numbers of earthquakes used for each individual year are shown in Table VI.

<table>
<thead>
<tr>
<th>Year</th>
<th>#eqs</th>
</tr>
</thead>
<tbody>
<tr>
<td>1996</td>
<td>496</td>
</tr>
<tr>
<td>1997</td>
<td>502</td>
</tr>
<tr>
<td>1998</td>
<td>638</td>
</tr>
<tr>
<td>1999</td>
<td>742</td>
</tr>
<tr>
<td>2000</td>
<td>724</td>
</tr>
<tr>
<td>2001</td>
<td>734</td>
</tr>
<tr>
<td>2002</td>
<td>650</td>
</tr>
<tr>
<td>2003</td>
<td>777</td>
</tr>
<tr>
<td>2004</td>
<td>906</td>
</tr>
</tbody>
</table>

The preferred results for the entire data set are those obtained on a grid with 2-km nodal spacing (Figure 3.4). These results may be considered to provide the best representation of the average three-dimensional structure of the Coso area for the period 1997 - 2003. Major anomalies that correlate with geological, morphological and geothermal features include a major negative $V_P$ and $V_S$ anomaly with a bipartite, hourglass shape in the east of the area extending throughout the depth slices –1 and 0 km b.s.l. This anomaly correlates closely with the Coso Wash and probably represents sedimentary valley fill. The results suggest that this valley extends from the surface to at least sea level in its northern part (the upper Coso Wash area) and at least to 1 km b.s.l, in its southern part (Coso Basin). Its vertical extent is thus 2-3 km beneath the upper Coso Wash area and 3-4 km beneath Coso Basin. This could be further studied using gravity modeling. An anomaly of similar sign and depth extent is visible at –1 km b.s.l. in the northwest of the area. The central part of the entire area has average or high wave speeds except towards the bottom of
the well-resolved volume, in the depth slice at 2 km b.s.l., where there is some evidence for a low- $V_P$, low-$V_S$ region.

The $V_P/V_S$ field shows a major negative $V_P/V_S$ anomaly at −1 km b.s.l. that correlates very closely with the geothermal well-field north of the latitude of seismic stations CE3 and CE1 (Figure 3.4). The well-field south of this latitude is characterized by high $V_P/V_S$ values at −1 km b.s.l. At sea level and deeper the shape of the $V_P/V_S$ anomaly changes. It becomes weaker and extends beneath the southern part of the well-field and is less extensive beneath the eastern part. At 1 km b.s.l. it is restricted in lateral extent and occupies a small area northeast of the well-field only. Below this, at 2 km b.s.l. a negative $V_P/V_S$ anomaly of larger extent underlies the east flank region, approximately beneath the saddle between the upper Coso Wash area and Coso Basin.

The negative $V_P/V_S$ anomaly that correlates with the geothermal field is characterized by high $V_P$ but even higher $V_S$. Thus it results from anomalously high $V_S$ rather than anomalously low $V_P$.

All the major features observed in the 2-km nodal spacing inversion, and described above, were also seen in the 1-km nodal spacing results. More fine detail is apparent in those results, however, and numerous smaller anomalies, along with higher amplitudes for some anomalies. The final weighted RMS arrival time for this inversion was only slightly lower than for the 2-km-nodal-spacing inversion, however, suggesting that little additional signal in the data is explained by the significantly more complex 1-km result.
Figure 3.4 The preferred results for the entire data set, obtained using a grid with 2-km nodal spacings and data from the period 1997 – 2003.

The objective of inverting each year separately was to investigate possible changes in structure with time that might be related to geothermal operations. Of particular interest is the negative $V_P/V_S$ anomaly that correlates with the geothermal field (Figure 3.4) which might be related to
production. This anomaly, in the shallowest two depth sections at 1 and 2 km below surface, strengthened overall throughout the period 1996 – 2004 (Figure 3.5). The strengthening is irregular from year to year. This result may be compared with results from The Geysers geothermal field. There, a clear strengthening of a negative $V_P/V_S$ anomaly associated with steam extraction was detectable in inversions of data collected at 2-year intervals 1991 – 1998 (Gunasekera and others, 2003). During this period steam production was $7 - 9 \times 10^{10}$ kg/yr (Barker and others, 1992). In comparison, fluid extraction from the Coso geothermal field for the period 1996 – 2004 has been fairly steady and approximately $4 \times 10^{10}$ kg/yr, along with injection at a steady rate of approximately $2 \times 10^{10}$ kg/yr. The net fluid loss rate is thus approximately $2 \times 10^{10}$ kg/yr.

The fluid extraction rate at the Coso geothermal field is approximately half that at The Geysers, suggesting that, if all else were equal, significant growth of the negative $V_P/V_S$ anomaly on a time-scale of ~4 years might be expected. The effect of reinjection on structural change in geothermal reservoirs has not to date been studied anywhere, but it might be expected that if the injected fluid either contributes to the fluid extracted, or replenishes depleted regions of the reservoir, then the net fluid loss rate is the appropriate figure to consider in estimating the likely time-scales over which reservoir structure might significantly change seismically. If so, and the net fluid extraction rate is approximately $2 \times 10^{10}$ kg/yr, it might be expected that clearly detectable changes would occur on a time scale of ~ 10 years.

Careful examination of Figure 3.5 shows that the negative $V_P/V_S$ anomaly is stronger in the last few years of the nine-year time period studied, compared with the first few years. This suggests qualitatively that the Coso geothermal field is behaving in a similar way to The Geysers field, but at a lower rate as a result of the much lower net fluid loss rate achieved by more modest production and significant reinjection.

The negative $V_P/V_S$ anomalies are associated with high and increasing $V_P$ and $V_S$, but $V_S$ increases at a greater rate than $V_P$. Processes expected to be associated with geothermal operations that can increase the value of $V_S$ compared with $V_P$ include a) steam flooding which lowers $V_P$ more than $V_S$ by increasing the compressibility of the pore fluid, b) decrease in fluid pressure, which raises $V_S$ more than $V_P$, and c) the drying of certain argillaceous minerals such as illite (Figure 3.6). All of these factors indicate reservoir fluid depletion, but only the latter two involve increases in the wave speeds. The temporal changes observed are thus consistent with pressure decrease and mineral drying in the reservoir, but not the replacement of liquid pore fluid with steam, unless this effect is camouflaged by stronger wave-speed increases caused by the other two processes. Precise determination of the exact processes at work requires detailed comparison of the results with operation history.
Figure 3.5 Results for individual years separately, nodal spacing: 2 km.
Figure 3.6 Schematic figure illustrating the effects of processes caused by exploitation on $V_P$, $V_S$ and $V_P/V_S$. Long arrows indicate the dominant effect, and short arrows indicate subsidiary effects. The three processes have differing effects on $V_P$ and $V_S$ but all cause $V_P/V_S$ to decrease.

3.4 Summary of Time-Dependent Tomography Results

1. Compared with the crustal model currently used by the U.S. Navy for their routine earthquake locations, the average one-dimensional crustal structure of the Coso area determined in this project using velest features somewhat lower wave speeds at shallow depth and significantly higher ones at greater depth. Use of a model with higher wave speeds in general will typically result in shallower earthquake hypocentres being calculated.

2. The area is characterized by relatively high $V_P/V_S$ in the upper ~4 km, beneath which it is relatively low. This might be due to petrological variations.

3. Inversions of a 4811-earthquake data set comprising 79,822 $P$ and $S$ travel times at the 2-km-nodal-spacing level revealed low $V_P$ and $V_S$ wave speeds associated with fill in the Coso Wash extending to a depth of 2-3 km beneath the upper Coso Wash area and 3-4 km beneath Coso Basin. A $V_P/V_S$ low occupies the northern and eastern part of the geothermal field at ~1 km b.s.l., and the northern and southern parts of the field at sea level.

4. Independent inversions for each of the years 1996 - 2004 separately show an irregular strengthening in the negative $V_P/V_S$ anomalies at ~1 km b.s.l. and at sea level. This progressive reduction in $V_P/V_S$ results predominately from the progressive relative increase of $V_S$ with respect to $V_P$. Such a progressive increase is expected to result from processes associated with geothermal operations such as decrease in fluid pressure and the drying of argillaceous minerals such as illite.
3.5 Preparation of data for tomographic inversion for the year 2005

During 2006 we completed tomographic analysis for the years 1996 – 2004 (USGS Open-File Report in preparation). We also extracted data for 2005 in preparation for extending the 4D tomographic analysis to that year. Figures 3.6 and 3.7 show a suite of plots indicating the quality, range and spatial distribution of the MEQs selected.

Figure 3.6. Plots showing (left) all MEQs from the Navy catalog, and (right) the highest-quality subset chosen for tomographic inversion, for 2005, with 2004 shown above for comparison.
2.3.3.4 Earthquake Moment Tensors

4.1 Objectives of Moment-Tensor Analysis

The full moment-tensor source mechanisms of microearthquakes at geothermal areas provide information, particularly about seismic volume changes, that conventional “fault-plane solutions” do not and that are potentially valuable for understanding physical processes accompanying activities such as energy extraction and fluid injection. Moment tensors for microearthquakes at several geothermal areas in Iceland (Miller and others, 1998), California (Ross and others, 1999), and Indonesia (Foulger, proprietary results) show significant seismic volume increases and decreases that are correlated with industrial activities such as injection and production.
Determining good moment tensors requires a seismometer network with well-distributed high-quality, calibrated, three-component seismometers surrounding the earthquakes of interest. As described above, in order to achieve this for the EGS experiments at the Coso geothermal area, the U.S. Navy network was supplemented with additional temporary stations. This network increased the station coverage, in particular in the neighborhood of planned injection experiment on the east flank.

In addition to major software development described in Section 6, moment tensor work focused on determination of seismic parameters associated with microearthquakes induced by injection into well 34-9RD2 on the east flank of the Coso geothermal area. This injection experiment was a primary experiment of the Enhanced Geothermal Systems (EGS) project. The location of well 34-9RD2 in the study area is shown in Figure 4.1.

![Figure 4.1: Map showing wells of the east flank of the Coso Geothermal area, including well 34-9RD2 that was stimulated in the EGS experiment.](image)

4.2 Sensor Polarities and Orientations
As for traditional fault plane solutions, the polarities of the vertical seismometer components are required. In addition, the orientations of the horizontal (“North” and “East”) components of the three-component stations are required. It proved to be a major task to assemble a reliable set of these data for the networks for the following reasons:

- The 22 permanent U.S. Navy stations are mostly in boreholes and thus the orientations of the horizontal components could not be measured directly in the field.
- These stations have been in place for a number of years and thus have a complex history of maintenance, and polarities and orientations may have changed with time.
- It was standard practice when deploying the temporary network stations to orient the “North” component to magnetic north using a compass. However, this was not always done, e.g., if the field party forgot to take a compass.
- It transpired that some of the sensors used for the portable network stations were wired up wrongly (Section 1.1). Pathologies included the “North” and “East” components being swapped, and components being reversed (e.g., “East” being really “West”).

Polarity and orientation data were assembled using a number of methods which included:

- Inherited, earlier information from the permanent network,
- Tapping or dropping weights vertically onto the surface sensors, including portable network sensors,
- Studying suites of fault-plane solutions to determine if individual stations appeared to have consistent normal or reversed responses,
- Studying the response of horizontal sensor components to earthquake waves arriving from known azimuths,
- Studying the directions and amplitudes of first arrivals recorded from a blast fired April 6th 2005

For the three-year period 2003 - 2005 inclusive, the situation was complicated further by the possibility that the polarities and orientations of sensors at individual stations had changed during this period. The best data set available for March 2005 is given in Table VII.

**Table VII – Polarities of Vertical Sensors and Orientations of Horizontal Sensors of Stations of U.S. Navy Permanent and Temporary Network Stations for March 2005**

<table>
<thead>
<tr>
<th>Injection 3</th>
<th>22nd Feb – 4th March, 2005</th>
<th>doy 053-063</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inj3 sensor</td>
<td>Inj3.polarity file</td>
<td>Orient'n of N compt</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>----------</td>
<td>-------</td>
<td>-------</td>
</tr>
<tr>
<td><strong>Permanent stations</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B01</td>
<td>-1</td>
<td>mag N</td>
</tr>
<tr>
<td>B02</td>
<td>L22</td>
<td>not known</td>
</tr>
<tr>
<td>CE1</td>
<td>-1</td>
<td>154</td>
</tr>
<tr>
<td>CE2</td>
<td>-1</td>
<td>198</td>
</tr>
<tr>
<td>CE3</td>
<td>-1</td>
<td></td>
</tr>
<tr>
<td>CE4</td>
<td>-1 (uncertain)</td>
<td>253</td>
</tr>
<tr>
<td>CE5</td>
<td>defunct</td>
<td>defunct</td>
</tr>
<tr>
<td>CE6</td>
<td>bad vertical</td>
<td>not known</td>
</tr>
<tr>
<td>CE7</td>
<td>-1</td>
<td>56</td>
</tr>
<tr>
<td>CE8</td>
<td>+1 (uncertain)</td>
<td>113 (uncertain)</td>
</tr>
<tr>
<td>NV10</td>
<td></td>
<td>55</td>
</tr>
<tr>
<td>NS10</td>
<td>L22?</td>
<td>-1</td>
</tr>
<tr>
<td>NV1</td>
<td>-1</td>
<td>49</td>
</tr>
<tr>
<td>NV2</td>
<td>+1</td>
<td>230</td>
</tr>
<tr>
<td>NV3</td>
<td>+1</td>
<td>303R</td>
</tr>
<tr>
<td>NV4</td>
<td>+1</td>
<td>51R</td>
</tr>
<tr>
<td>NV5</td>
<td>+1</td>
<td>77R</td>
</tr>
<tr>
<td>NS5</td>
<td>L22?</td>
<td>-1</td>
</tr>
<tr>
<td>NV6</td>
<td>+1</td>
<td>10R</td>
</tr>
<tr>
<td>NV9</td>
<td>defunct</td>
<td>defunct</td>
</tr>
<tr>
<td>W1S</td>
<td>-1</td>
<td>209</td>
</tr>
<tr>
<td>W2S</td>
<td>+1</td>
<td>not known</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Portable stations</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B3</td>
<td>L22</td>
<td>-1</td>
</tr>
<tr>
<td>B4</td>
<td>L22</td>
<td>+1</td>
</tr>
<tr>
<td>B5</td>
<td>CMG3</td>
<td>+1</td>
</tr>
<tr>
<td>C1</td>
<td>L22</td>
<td>-1</td>
</tr>
<tr>
<td>C2</td>
<td>-1</td>
<td>mag N</td>
</tr>
<tr>
<td>C3</td>
<td>-1</td>
<td>mag N</td>
</tr>
<tr>
<td>C4</td>
<td>L22</td>
<td>-1</td>
</tr>
<tr>
<td>C5</td>
<td>-1</td>
<td>mag N</td>
</tr>
<tr>
<td>C6</td>
<td>CMG3</td>
<td>+1</td>
</tr>
<tr>
<td>C7</td>
<td>-1</td>
<td>mag N</td>
</tr>
<tr>
<td>C8</td>
<td>L22</td>
<td>-1</td>
</tr>
<tr>
<td>C9</td>
<td>not operating</td>
<td>mag N</td>
</tr>
<tr>
<td>C10</td>
<td>L22</td>
<td>-1</td>
</tr>
<tr>
<td>C11</td>
<td>Geospace</td>
<td>-1</td>
</tr>
<tr>
<td>C12</td>
<td>-1</td>
<td>mag N</td>
</tr>
</tbody>
</table>
4.3 Results

The quality of data recorded by the two networks was excellent. In particular the sensors of the permanent network installed in boreholes yielded impulsive P- and S-wave arrivals with little noise (Figure 4.2).

![Figure 4.2: 2 minutes of excellent, 3-component seismic data recorded at the U.S. Navy borehole seismometer CE1. Note the superb quality of S-wave arrivals, that enable excellent P:S-wave amplitude ratios to be measured and provide strong constraints on the moment tensors.]

Moment tensors were obtained for a number of well-recorded earthquakes that occurred on the east flank, March 2005. The P-, SH- and SV-polarities, and P:SH and SH:SV amplitude ratio fields are shown for six examples in Figure 4.3.
22/20050222193415  FEASIBLE (L1 = -2.26311e-07)

22/20050222193443  OPTIMAL (L1 = 0.0899804)

03/20050303030743  OPTIMAL (L1 = 0.0237064)
Figure 4.3. Summary of the results for six well-recorded earthquakes that occurred on the east flank in March 2005. All circles represent upper focal sphere equal-area projections. For each earthquake, the upper three circles show P, SH and SV polarity plots, along with the best-fit nodal (zero P-wave amplitude) lines. Positive P-wave motion is outward, positive SH motion is to the right (clockwise) as viewed from above the source, and positive SV motion is upwards (towards the zenith). Positive motions are shown as filled circles, and negative motions as open circles. Squares represent
down-going rays plotted at the antipodal point on the upper focal hemisphere. Lower two circles: P:SH and SH:SV ratios, displayed using the convention shown in Figure A3 (Julian and Foulger, 1996).

Good moment tensors were obtained for a total of 38 earthquakes prior to, during, and following the March 2005 injection experiment. The earthquakes showed predominately volume increases, consistent with the opening of cracks and cavities in response to the injection of fluid into the formation beneath the East Flank. A full interpretation, joint with the results of relative relocations, is given below in Section 5.

2.3.3.5 The EGS Experiment in Well 34-9RD2, March 2005: Integrated Interpretation

5.1 Background

Injection of fluids into critically stressed rock, or induction of such stress by injection under pressure, has the potential to create new cracks or extend pre-existing ones through the process of hydraulic fracture. This process is seismogenic and results in swarms of earthquakes caused by the breaking of rock along the flow path of the injected fluids. Analyzing these earthquakes is essentially the only way to obtain detailed information about the orientation of the cracks stimulated, their dimensions and mode of failure, and thus the immediate trajectory of the injected fluids once they leave the borehole. Information may also be obtained about the stress cycle accompanying the injection, i.e., stress before, during and following the injection. This information relates to the longer-term effects of the injection.

Traditional microearthquake analyses yield only a general picture of the effects of fluid injection. Standard earthquake locations are typically only accurate relative to one another at the level of hundreds of meters – many hundreds of meters for poor seismometer networks or a few for high-quality networks such as that operated at Coso. Locating injection-related earthquake sequences with such methods typically yields diffuse clouds of locations that may give some idea of the direction in which the fluids migrated, but little in the way of precise detail of the orientation of the permeability zone stimulated. There may also be systematic errors if a one-dimensional crustal model only is used. Likewise, traditional fault-plane analysis of earthquake mechanisms gives only a rough picture of the orientation of fractures stimulated (it cannot constrain volumetric components, i.e., crack opening or closure) and the local stress field.

We used a powerful combination of new techniques to study the injection test performed in well 34-9RD2 in March 2005. We calculated accurate relative hypocenter locations using hypocc (Section 2) along with highly accurate moment tensors for the largest earthquakes. We used a rich data set from stations both of the permanent U.S. Navy network and the temporary network (Section 1). By combining both types of result we were able to greatly reduce ambiguity concerning the orientation and mode of failure of the fractures stimulated. This module of work was highly successful, and it comprised a unique study and a proof of concept of the method.

5.2 History of the Injection Test
The EGS injector well 34-9RD2 was reworked, drilled and stimulated February - March 2005. Massive mud losses started late March 2nd, indicating that the drilling mud had been lost into the formation near the bottom of the well at ~2,660 m depth. Although this event had not been planned, it nevertheless comprised an injection, albeit of drilling mud rather than water as had been planned initially.

The mud injection stimulated considerable seismicity. Of the large, well-recorded earthquakes that were successfully processed, the first that might be associated with the injection operation occurred 2nd March, 22:20 hrs and had a magnitude of M 0.5. Including this earthquake, a total of 7 were successfully processed in the period 2nd March 22:20 - 3rd March 01:25.

Starting 3rd March, 03:07 hrs, an intense swarm of earthquakes occurred, the largest of which had a magnitude of M 2.6 (Figure 5.1) and was felt by personnel at the well head. This swarm lasted ~ 50 minutes, but most of the largest earthquakes occurred in the first 2 minutes (Figure 5.1). Earthquakes as small as magnitude M 0.3 were located. Two rotatable 3D views of the microearthquake locations are available at the password-protected web site http://cosomeq.wr.usgs.gov.

Figure 5.1: Magnitude-time plot for 1st - 29th March 2005. Each UTC day begins at the axis tick. Seismicity associated with the injection of drilling mud started about 23:00 UTC (14:00 PST) on March 2nd. The ticks on the lower plot are one hour apart.
The earthquakes selected for study were those that occurred during the month of March 2005 and whose epicenters lay within 1 km of the seismic station CE6, which was near to the head of well 34-9RD2 (Figure 5.2). The entire data set examined contained 204 earthquakes, of which a subset of the highest quality gave good relative relocations and moment tensors.

Figure 5.2: Map of the Coso geothermal area showing seismometer networks (green symbols), surface projections of wells (red lines). Earthquakes that occurred during March 2005 and whose epicenters lay within the blue circle were selected for study.

5.3 Relative Relocation Results

The results of relatively relocating the injection-related earthquakes are shown in Figure 5.3. The left panel shows locations from the U.S. Navy catalogue. These locations were obtained by processing each earthquake separately (Section 2). The locations form a diffuse cluster and little
structure can be discerned. Furthermore, they are mostly located at or just below sea level (indicated by the intersection of the N, E and Down axes).

The right panel shows the relative relocations. Because of the nature of the calculations, only a subset of the best-recorded earthquakes are successfully relocated. More structure can be seen than in the U.S. Navy routine locations (right panel) and this is particularly clearly seen in the rotatable 3-D plots available on the website. The diagrams shown in Figure 5.4 are orientated in order to show best that the swarm earthquakes (plotted in yellow) delineate a plane, i.e. their distribution extends in and out of the plane of the page.

![Figure 5.3: Three-dimensional depiction of earthquake hypocenters. Green: pre-swarm earthquakes, yellow: swarm earthquakes, red: post-swarm earthquakes. Left: locations from U.S. Navy catalog, Right: relative relocations. Boreholes are shown in purple and the well bore of well 34-9RD2 is indicated. The N, E and Down axes intersect at sea level.](image)

Figure 5.4 shows more detail of the evolution in time and space of the swarm. During the earliest, most intense part of the swarm, seismicity migrated northwards, eastwards and up, indicating the geometry and chronology of rupture. The dimensions of the rupture plane are 600 m vertically and 700 m horizontally, and the plane strikes N 20°E.
Figure 5.4: Migration of swarm earthquakes in time and space.

5.4 Moment-Tensor Results

Moment tensors were successfully obtained for all earthquakes within 1 km of seismic station CE6 during the month of March 2005 as follows:

- 7 earthquakes prior to the main swarm,
- 14 earthquakes during the main swarm, and
- 17 earthquakes following the main swarm
Figure 5.5 shows a typical result for a co-swarm event. This mechanism is consistent with failure on the N 20°E-trending plane delineated by the relative relocations, and it furthermore has a net explosive mechanism.

Figure 5.5: Moment tensor results for an earthquake that occurred 3 March 2005, 03:07:33 UTC. Plotting convention as for Figure 4.3. Circle at bottom right shows seismic stations on an equal-area, upper-hemisphere plot.

Figure 5.6 shows 8 example earthquakes from the 14 swarm earthquakes processed. There is great uniformity of moment tensor type. The seismic zone delineated by the relative relocations (red line) does not correspond to either possible shear fault plane suggested by the results, but is instead consistent with the crack-opening component.
Figure 5.6: Summary diagram showing 8 example moment tensors for earthquakes from the swarm. The red line indicates the orientation of the seismic zone revealed by the earthquake relocations.

Figures 5.7 and 5.8 show similar example results for the set of 17 post-swarm earthquakes that was successfully processed. These earthquakes clearly have different mechanisms, and Figure 5.8 shows that these mechanisms are also very variable, in contrast with the great uniformity of the swarm earthquakes.

Figure 5.7: As for Figure 5.5 but for an earthquake of 29 March 2005, 12:09:43 UTC.
The results are summarized in Figures 5.9 and 5.10, which show source-type plots and the orientations of the “pressure” and “tension” axes respectively. Several deductions may be made:

- The pre-, co- and post-swarm earthquakes represent different modes of failure.
- All the pre- and co-swarm earthquakes had explosive mechanisms, whereas some of the post-swarm earthquakes had implosive mechanisms.
- Some of the pre- and post-swarm earthquakes had +CLVD components whereas none of the co-swarm earthquakes did.

The pre-swarm earthquakes form a uniform set with pressure axes sub-vertical and tension axes sub-horizontal. This contrasts with the co-swarm earthquakes which mostly had P-axes ranging from sub-vertical to SW orientated and sub-horizontal, and T-axes sub-horizontal and trending dominantly WNW. The orientation of principal axes for the post-swarm earthquakes resembled the pre-swarm earthquake set but there was much more variation (Figure 5.11).

These results may be interpreted as follows.
Prior to the injection experiment seismicity was consistent with a homogeneous stress field with a sub-vertical orientation of greatest compressional stress and a sub-horizontal, WNW-NW orientation of least compressive stress. Subsidiary failure occurred in response to local occurrences NE-orientated least compressive stress. Mode of failure varied from near volume-conserving to explosive.

Introduction of fluid into the formation modified the stress field, as is shown by the different type of seismic failure. The swarm earthquakes are consistent with a greater influence of sub-horizontal, SW-orientated greatest compressional stress. +CLVD components in earthquakes are not well understood but may be related to compensated closure of cavities. If so, their absence in
the swarm earthquake mechanisms would be consistent with the mode of failure being limited to cavity opening.

The suite of earthquakes that occurred after the swarm activity indicated more varied orientations of principal stress than before. This suggests a) that the injection experiment released much of the deviatoric stress locally such that the maximum and minimum principal stresses were more nearly equal than before, and b) that the injection-induced stress-field modification lasted at least until the end of March, i.e., for at least a month following injection.

5.5 Model for co-injection seismicity

Figure 5.12 summarizes the relative-relocation and the moment-tensor results. The combined results suggest that, as fluid entered the formation, a pre-existing fault (zone) was activated, extended, widened and opened. This fault (zone) had a strike of N 20˚E, was 700 m long and 600 m high. It extended from near the bottom of well 34-9RD2 in a NE direction. Rupture progressed from the lower, SW end of the fault (zone) to the upper NE end. This orientation is inconsistent with any shear interpretation of the moment tensors, but is consistent with the crack-opening component in the mechanisms.

We tentatively suggest an “ear of corn” model for growth of the fault (zone) (Figure 5.12). The pre-existing fault (zone) is represented by the “kernel” (red), which progressively extends and widens as the earthquake swarm progresses. Shear faulting on “wing faults” accompanies activation of the main fault (zone) and accounts for the observed shear components in the moment tensors. This interpretation is not unique, and would benefit from future re-examination in collaboration with structural geologists familiar with the geology of the Coso geothermal field.
Pre-swarm  Co-swarm  Post-swarm

Figure 5.9: The results in “source-type” space. The “source-type” plot depicts the moment tensor in a form that is independent of source orientation. All simple shear-faulting mechanisms, whether strike-slip, normal or reverse, plot at the central point labeled DC (= double couple). The vertical coordinate k ranges from –1 (–V) at the bottom to +1 (+V) at the top of the plot, and indicates the magnitude and sign of the volume change involved. Mechanisms with explosive (volume increase) components lie above the horizontal line through the central point DC, and mechanisms with volume decreases lie below it. Pure, spherically symmetric explosions plot at point +V and pure implosions plot at –V. The left-right coordinate T ranges from –1 on the left (+CLVD) to +1 on the right (–CLVD) side of the plot, and indicates the type of shear involved, with simple shears lying on the vertical line T=0 through the central point DC and more complex pure shears lying to the right or left of this line. In particular, opening (closing) tensile cracks, which involve both shear and volumetric deformation, lie at the point +Crack (–Crack). The points ±CLVD and ±Dipole represent mathematically idealized force systems whose possible physical significance is not clear, but probably related to the opening and closure of cracks in the presence of compensating fluid flow.

Pre-swarm  Co-swarm  Post-swarm

Figure 5.10: Pressure (P) and tension (T) axes for the pre-, co- and post-swarm earthquakes, plotted on upper-hemisphere stereographic projections. The P and T axes give a rough indication of the orientation of the greatest and least principal stresses respectively.
5.6 Pre-injection baseline seismicity

During 2006, we obtained moment tensors for 22 earthquakes near well 34-9RD2 from February 2005, 16 of them of “good” quality. Table VIII gives the dates and times of these MEQs, and Figure 5.12 shows the P and T axes and source types of their moment tensors. It can be seen from Table VIII that 6 MEQs occurred within an interval of about 7 hours on 25th February. Figure 5.13 shows the moment tensor results for this interval.

For the data set for the entire month, and for the subset from 25th February, the orientations of the P and T axes are compatible with normal to strike-slip failure on NE-trending faults.
consistent with the local and regional tectonics. On the source-type plots, the mechanisms range between the +Dipole, through the DC, to the -Dipole fields. DC corresponds to shear faulting. The interpretation of +Dipole (-Dipole) is non-unique, but is consistent with opening (closing) cracks, with the seismic radiation partly compensated by the inflow (outflow) of fluids into (from) the cavity. The distributions on both source-type plots shown here are similar to those from other geothermal areas in extending shear zones, e.g., The Geysers, and indicate volumetric components varying between significant opening and closing.

The swarm of six MEQs from 10:02 to 17:13 25th February somewhat surprisingly shows mixed source types, not significantly different from the month as a whole, suggesting that these events did not occur as a result of activation of a single fault.

The source orientations for February 2005 are different from those for either the pre-, co- or post-swarm MEQs (Figure 5.14). This fact, and the variable mode of failure in the Coso area, suggests that February may characterise the “normal background” mode of failure in the vicinity of 34-9RD2 better than the “pre-swarm” MEQs that occurred shortly prior to the “co-swarm” injection-related ones. If this inference is correct, it follows that the pre-, co- and post-swarm MEQs were all influenced by the drilling and injection activities. Figure 5.15 shows focal-sphere plots for the individual moment tensors.

We have begun deriving moment tensors for MEQs in the vicinity of 34-9RD2 for April 2005. Approximately 40 MEQs from this month are of adequate quality, and at the time of writing nine have been studied and five have yielded “good” moment tensors. Processing of the MEQ set for April will be completed soon, and this will probably complete the moment tensor analysis necessary to fully characterise the injection experiment in well 34-9RD2.

Table VIII. Dates and times of MEQs from February 2005 that yielded “good” moment tensors.

<table>
<thead>
<tr>
<th>Date</th>
<th>Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>20050203</td>
<td>17:05</td>
</tr>
<tr>
<td>20050204</td>
<td>08:07</td>
</tr>
<tr>
<td>20050214</td>
<td>01:44</td>
</tr>
<tr>
<td>20050215</td>
<td>16:28</td>
</tr>
<tr>
<td>20050225</td>
<td>10:02</td>
</tr>
<tr>
<td>20050225</td>
<td>16:47</td>
</tr>
<tr>
<td>20050227</td>
<td>23:46</td>
</tr>
</tbody>
</table>
Figure 5.12. Plots of (top) $P$ and $T$ axes, and (bottom) source types, for the 16 “good” moment tensors obtained from February 2005.
Figure 5.13. Plots of (top) $P$ and $T$ axes, and (bottom) source types, for the 6 “good” moment tensors from a 7-hr period 25th February 2005.

Figure 5.14. Plots of $P$ and $T$ axes for the pre-, co- and post-injection MEQs from March 2005.
February 2006 "GOOD" moment tensors, page 1

03/20050203170537  OPTIMAL (L1 = 4.47035e-09)

04/20050204080716  OPTIMAL (L1 = 0.0956347)

04/20050204080751  FEASIBLE (L1 = -9.71596e-08)

14/20050214014450  OPTIMAL (L1 = 0.174711)

15/20050215162839  OPTIMAL (L1 = 0.0469175)

15/20050215162912  OPTIMAL (L1 = -1.73069e-07)
Figure 5.15. Focal-sphere plots of individual moment tensors for MEQs from February 2005. For each event, the top three plots show first-motion polarities and the bottom two plots show amplitude ratios.

2.3.3.6 Software Development

Seismological studies at Coso under this project require the development of a significant amount of computer software.

6.1 Earthquake Source-Mechanism Determination

The full (moment-tensor) mechanisms of microearthquakes provide a rich source of information about active processes in geothermal reservoirs, particularly when combined with high-resolution hypocenter locations. Most existing methods for determining moment tensors, however, are applicable only to earthquakes larger than about magnitude 4, and thus are of little use in geothermal contexts. Only the amplitude-ratio method (Julian, 1986; Julian and Foulger, 1996) presently can provide accurate moment tensors for microearthquakes. Existing software based on this method is inefficient to use, however, involving several poorly integrated computer
programs and requiring excessive user interaction and file manipulation, so that analyzing large numbers of microearthquakes is impractical.

A major task under this project is designing and implementing efficient moment-tensor software with a modern graphical user interface (GUI). This software will make it much faster and easier to determine moment tensors that fit observed seismic-wave data and enable users to experiment conveniently with the effects of including or excluding individual observations, changing their weights, etc. We plan to use it both for conducting research into microearthquake processes at Coso and elsewhere and for routinely computing moment tensors as part of the U.S. Navy’s seismic monitoring of the Coso field.

The new software, eqmec, is written in the C++ language and uses Qt (http://www.trolltech.com/products/qt) (Dalheimer, 2002), a C++ class library and toolkit for writing portable graphical user interfaces. Using Qt offers several benefits: Qt is an exceptionally high-quality product, featuring a wealth of well-designed components. Qt programs run on all important kinds of hardware, including Apple Macintoshes, IBM PCs, and SUN workstations, and operating systems, including UNIX, LINUX, Win32, and Mac OSX. Because C++ compilers generate native machine code, Qt programs execute efficiently.

Figure 6.1 shows an example of the main eqmec display, for data from the Navy’s catalog for a microearthquake within the Coso field. The tables show data in numerical form and allow users to exclude or include data from the inversion. The circular focal-hemisphere plots display observed polarities and amplitude ratios along with theoretical values. The lozenge-shaped “Source-Type Plot” (Hudson and others, 1989), displays an orientation-independent description of the mechanism (the new information contained in the moment tensor, over and above the simple orientation information that characterizes a “fault-plane solution”. Points in the upper half of the plot, such as that shown in Figures 6.1, indicate mechanisms with volume increases.
Figure 6.1: Example of the eqmec interactive display for a microearthquake at Coso. The upper table shows all the seismic-wave observations ("picks"), and the lower table shows the amplitude ratios derived from them. Focal-sphere plots on the right show the observed wave polarities (above) and the amplitude ratios (below). Individual data can be highlighted (green) by clicking either rows of the tables on the left or symbols on the focal-hemisphere plots on the right. Checkboxes in the table allow interactive control of which data are used in the moment-tensor inversion, invoked by the Invert button at the top. The focal-sphere plots show theoretical principal axis positions (T, I, P), nodal curves, and amplitude ratios (gray arrows) for the computed mechanism. The "penalty" values in the tables indicate the magnitude of the misfit for those data that are not satisfied in the inversion. The lozenge-shaped figure is a "source-type" plot. The display shown is that on a Macintosh computer. On other systems, the appearance of the window follows local conventions.
6.2 Three-Dimensional Visualization
A mundane, but critical, need in a project such as this is for tools for visualizing three-dimensional objects such as points (such as earthquake hypocenters), curves (well-bores), scalar fields (temperature, seismic-wave speeds), and tensor fields (stress). We have identified two computer facilities for this purpose, ParaView and LiveGraphics3D, and have written programs to convert Coso data into formats used by these programs.

ParaView ([http://www-vis.lbl.gov/NERSC/Software/paraview/docs/HTML/paraview.htm](http://www-vis.lbl.gov/NERSC/Software/paraview/docs/HTML/paraview.htm) and [http://www.paraview.org/HTML/Index.html](http://www.paraview.org/HTML/Index.html)) is an open-source visualization application, developed with the support of the National Nuclear Security Administration’s (NNSA) Advanced Simulation and Computing (ASC) program and the Sandia National Laboratories (SNL), Los Alamos National Laboratory (LANL), and Lawrence Livermore National Laboratory (LLNL). ParaView runs on Windows, Mac OS X, and UNIX operating systems, and makes powerful three-dimensional visualization available on all commonly used types of workstations. Because ParaView source code is freely available and not proprietary, its continued availability cannot be threatened by such factors as changes in corporate policy. ParaView is a compiled program, so it executes efficiently, and it supports parallel processors, so it can be applied to extremely large data sets when necessary. Even with a single processor, our tests show that response is essentially instantaneous when displaying 100,000 earthquake hypocenters on a laptop computer. Figure 6.1 shows an example of a ParaView display.
Figure 6.2: ParaView display showing the distribution of seismic compressional-wave speeds at Coso as determined in the tomographic study described above in Section 3. The user can interactively rotate the view, change the color scale, and move the plane of the cross-sectional slice. The volume shown is 10 X 10 km horizontally and 11 km deep. View is to the southwest.

At the same time, ParaView has disadvantages: it is large and complex, and installing it on a computer can be a sizeable task. For communicating results rapidly to other workers on the EGS project, we have set up a secure password-protected web site, http://cosomeq.wr.usgs.gov, that displays interactive rotatable three-dimensional microearthquake hypocenter images using the public-domain program LiveGraphics3D (http://wwwvis.informatik.uni-stuttgart.de/~kraus/LiveGraphics3D). This program is much less efficient than ParaView, but it is adequate for displaying small numbers (hundreds) of microearthquakes and, because it runs
on any web browser, requires no special installation. Figure 5.3 shows an example of a
LiveGraphics3D display.

6.3 Major Programs Written or Significantly Modified to Date

Earthquake Source-Mechanisms

qbme – Graphical user interface for determining moment tensors

Earthquake Hypocenter Location

cat2dt – Generate time-difference data from earthquake catalog
hypocc – Simultaneously locate clusters of earthquakes
libttb3d – Body-wave travel-time library for three-dimensional Earth models
libttlpyr – Body-wave travel-time library for plane-layered Earth models
qloc – Locate earthquakes one at a time
toonpics – Refine relative phase times by waveform cross-correlation

Data Access and Display

coso23d – format Coso earthquake catalog for viewing with LiveGraphics3D
coso2xyz – format Coso earthquake catalog for viewing with IFRIT (obsolete)
cosomextract – Get seismic-wave reading data for specified Coso earthquakes
cosofetch – Look up Coso earthquakes in any time interval
cosomap – Plot earthquakes and other geophysical data on map of Coso area.
cosowells – Look up traces of geothermal well boreholes
hdd2xyz – format hypocc/hypoDD hypocenters for viewing with IFRIT (obsolete)
hdd2vtk – format hypocc/hypoDD hypocenters for viewing with ParaView
qselect – Select earthquakes satisfying user-defined criteria
simul2vtk – Convert tomographic models for viewing with ParaView
wells2vtk – Format well-bore traces for viewing with ParaView

Seismic Tomography

cosoqual – Estimate quality of arrival-time data for Coso-format seismic events
simulspread – Evaluate resolution of tomographic models

Data Management

qmatch – Match earthquakes in two catalogs by origin times
segymmerge – Extract continuous-time data from REFTEK data-logger files

These programs are available on request from B.R. Julian at the U.S. Geological Survey
(julian@usgs.gov).
2.3.3.7 Publications and Presentations


2.3.3.8 References

Dalheimer, M.K., 2002, Programming With Qt (Second ed.): Köln, Germany, O'Reilly, 499 p.


2.4 Mechanical, Mineralogical, and Petrophysical Analysis of Fracture Permeability (Nick Davatzes and Steve Hickman)

2.4.1 Background and Objectives

The active precipitation of minerals characteristic to hydrothermal systems implies that fractures conducting fluids in the subsurface will heal and permeability will be lost. In tectonically active regions, this permeability might be regenerated by reactivation of healed fractures that are critically stressed for failure or by the formation of new fractures (Barton et al., 1995, 1998). However, chemical alteration of host-rock mineralogy by hydrothermal fluids produces increasing proportions of phyllosilicates and reduces the strength of grain contacts. This reduction in strength, and an associated increase in ductility, could inhibit the generation of secondary porosity during fracture formation or slip that is necessary to generate permeability. Thus, chemical alteration state could exert a profound influence on the regeneration of fracture permeability in geothermal systems that would counteract, or at least modulate, the role of slip on fractures in maintaining high reservoir permeability.

In this report we summarize the accomplishments of the past year (2006) and the milestones for the next year. The bulk of the report presents a revised and updated analysis of available stress data from across the geothermal field in preparation for the stimulation experiment in 46A-19RD. The results are invaluable for developing improved methods for identifying and efficiently exploiting geothermal resources for the production of electricity in the region.

2.4.2 Summary of Accomplishments

Our research in this last year primarily focused on integrating available stress data from well bore failure and hydraulic fracturing tests with new results on the mechanical properties of core samples from Coso. Data from wells in the East Flank and Coso Wash as well as focal mechanism inversions from across the geothermal field were then compared to available data on the fault network in preparation for the stimulation experiment in 46A-19RD. Other long-term work continued including analysis of data in wells 58A-10 and 34-9RD2. Our specific accomplishments during 2006 were:

- Refined initial stress orientation picks based on reanalysis of Formation Micro-scanner (FMS) image log data, supplemented by borehole televiewer log (BHTV) data acquired in February and March 2005.
- Conducted rock deformation experiments on core to determine rock strength (including the uniaxial compressive strength $C_0$) and its relationship to sonic P-wave Velocity ($V_P$), porosity and density. These measurements are being used in conjunction with well-log-derived P-wave velocities and densities to determine variations in rock strength with depth in selected Coso wells, including 46A-19RD.
- Developed new empirical rock strength model to relate $V_P$ to uniaxial compressive rock strength ($C_0$)
- Used new empirical rock strength model to refine East Flank and Coso Wash geomechanical stress models using mini hydraulic fracturing tests and observations of borehole wall failure from FMS and BHTV image logs.
• Developed initial guidelines for maximum injection pressures that will cause shear failure of existing fractures without initiating tensile failure by hydrofracture.
• Stress model allows the computation of the tendency for shear failure on natural fractures and cross-correlation of the results with the distribution of temperature gradient anomalies indicative of fluid flow and the texture of the fault zones visible in image logs.
• Refined our understanding of petal-centerline fracture formation and their utility as indicators of stress state.
• Specified geophysical logging needs for 46A-19RD

2.4.3 Milestones

In 2007 our efforts will be focused on acquiring downhole measurements needed to develop conduct and analyze the stimulation of well 46A-19RD.
• Acquire and analyze BHTV logs from well 46A-19RD using USGS logging truck and ABI85 televiewer.
• Supervise acquisition of commercial geophysical well logs: 1) density, P-wave velocity, tool head temperature and natural gamma and 2) temperature-pressure-spinner (TPS).
• Plan, execute, and analyze mini-hydraulic fracturing test for magnitude of least horizontal principal stress, \( S_{hmin} \)
• Conduct initial analysis of BHTV logs for stress orientations and relative magnitudes and fault and fracture characteristics
• Conduct initial analysis of commercialgeophysical well log data to characterize fault and fracture characteristics and geomechanical rock properties
• Develop preliminary stress model for 46A-19RD and use stress model to help design massive hydraulic stimulation
• Participate in pre-stimulation hydraulic testing and analysis
• Participate in execution of massive hydraulic stimulation
• Participate in post-stimulation hydraulic testing and TPS logging
• Begin detailed post-stimulation geomechanical analysis and identification of flowing zones and their characteristics

2.4.4 Accomplishments

2.4.4.1 Stress and Faulting in the Coso Geothermal Field: Update and Recent Results from the East Flank and Coso Wash

*Summary of Key Results from 2006*
We have integrated new geologic mapping and measurements of stress orientations and magnitudes from wells 34-9RD2 and 58A-10 with existing data sets to refine a geomechanical model for the Coso geothermal field. Vertically averaged stress orientations across the field are fairly uniform and are consistent with focal mechanism inversions of earthquake clusters for stress and incremental strain. Active faults trending NNW-SSE to NNE-SSW are well oriented for normal slip in the current stress field, where the mean \( S_{hmin} \) orientation is 108° ± 24° in a transitional strike-slip to normal faulting stress regime. These structures bound regions of intense micro-seismicity and are complexly associated with surface hydrothermal activity. WNW-ESE trending faults are also associated with distinct regions of enhanced seismicity but are only
associated with surface hydrothermal activity where they intersect more northerly trending normal faults. These faults show no evidence for Quaternary slip at the surface and are poorly oriented in the modern stress field. Results from triaxial deformation experiments indicate that the various dioritic rocks which host the geothermal field are quite strong, demonstrating both high peak strengths and coefficient of friction in excess of 0.75 on fresh fracture surfaces. These results together with stress magnitudes measured in the East Flank of the field and inferred for Coso Wash just east of the field suggest that the most productive portions of the Coso geothermal field are in stress environments conducive to normal faulting. In addition, significant horizontal principal stress rotations are recorded by drilling-induced structures in borehole image logs. These variations in the azimuth of induced structures suggest local stress heterogeneity induced by active fault slip and are consistent with the high rates of seismicity observed in the geothermal field.

**Introduction**

The critical elements of a successful analysis of well 46A-19RD includes a thorough understanding of the fault and fracture system hosting fluid flow, the physical properties of these fractures and their host rock, and the stress state driving deformation at Coso. Therefore, in this contribution, we first discuss the faults that make up the geothermal field. Second we present new measurements of the mechanical properties of representative rock types obtained from wells 34-9RD2 and 64-16 in the East Flank of the geothermal field. Finally, we use this information and constraints from borehole image log analysis and min-hydraulic fracturing tests to develop a stress model for the Coso geothermal field (CGF). This geomechanical model is essential to understanding the mechanical interactions and permeability of fault zones, their natural evolution, and their response to engineered stimulation. In addition, this model is a critical element of the stimulation strategy that will be applied to Enhanced Geothermal Systems (EGS) well 46A-19RD in the southwest portion of the geothermal field in 2007.

### 2.4.1.1 The Fault System

In this section we integrate existing fault maps with our own field observations within the active geothermal field to define the fault geometry. However, for brevity we do not present an exhaustive discussion of the rich data set available nor do we discuss conditions at the boundary of the geothermal field. In addition, the full three-dimensional geometry of these faults and their mechanical relationships are subjects of on-going research.

Faults within the CGF can be broken into two distinct groups based on their geometry and inferred style of faulting (Figure 1). One group consists of WNW trending and minor NE trending faults. Many of these faults extend well outside the field and form prominent lineaments. These faults are interpreted as dextral and sinistral strike-slip faults respectively by Duffield *et al.* (1981) and Roquemore (1984). The extent to which these faults are currently active is not entirely clear at this time. They are exposed most often in bedrock and do not clearly offset any Quaternary sediment, but are associated with diffuse micro-seismicity in the geothermal field and with some minor geomorphic expression. The relationship of the diffuse cloud of seismicity to the faults is difficult to interpret at this time, but this problem may be solved by the efforts of the Navy Geothermal Program Office and the U.S. Geological Survey to...
more accurately relocate these earthquakes. At this time, we interpret these faults to be relatively inactive.

The other group consists of normal faults that dominantly trend N to NNE and dip both west and east (Figure 1a). The most prominent of these fault systems is the Coso Wash normal fault which coincides with the eastern margin of the geothermal field. It is composed of several en-echelon NNE-SSW trending segments variably connected by NW-trending, probably oblique-slip, faults. Normal faults appear to have been active in the Quaternary based on geomorphic expression (Angela Jayko, pers. comm. 2004), offset hydrothermal deposits (Hulen, 1978), and offset basalt flows (Figure 1a). A subset of this normal fault population also offsets Holocene basin sediments (Unruh and Streig, 2004), creates local sediment catchments, and is associated with seismicity. Thus, we interpret these faults to be actively slipping.

The normal faults divide the geothermal field into three main geologic sub-regions (Figure 1a): the Main Field, a central spine of exposed bedrock which includes the East Flank region, and Coso Wash. The Main Field is associated with high seismicity rates, high temperatures (>640°F at <10,000 ft depth), and Quaternary rhyolite domes (Bishop and Bird, 1987). The spine of exposed bedrock extends north to south and its intensely normal faulted eastern margin hosts the East Flank reservoir. With the exception of the East Flank region, which is associated with high temperatures and seismicity, the central region is largely aseismic and cool (Lutz et al., 1996). The East Flank also stands out from the rest of this area because of the high density of normal faults roughly located on the footwall side of a step between two Coso Wash normal fault segments. Coso Wash is a series of sub-basins associated with segments of the Coso Wash fault and experiences the least seismicity and lowest temperatures in the study area (Davatzes and Hickman, 2005b). The intersection of the N to NNE normal faults with the WNW faults dissects all three regions of the geothermal field into rhombohedral fault-bounded blocks.
Figure 1: (a) Tectonic map of the east flank of the Coso geothermal field over shaded relief image of topography. Location of alteration, fumaroles, and steaming ground is based on new mapping and results from Hulen (1978), Duffield et al. (1980), Whitmarsh (1998), Jayko (Personal communication, 2004), and work by Unruh and Streig (2004), Unruh and Hauksson (2006). (b) Minimum horizontal stress orientations inferred from borehole image logs from Geomechanics International (2003), Sheridan et al. (2003), Sheridan and Hickman (2004) and Davatzes and Hickman (2005a). Wells discussed in this paper are indicated, as are stresses and incremental strains inferred from clusters of seismicity from 1980 to 1995 (Feng and Lees, 1998) and 1980 to 1998 (Unruh et al., 2002). Both analysis combine data from the Southern California Seismic Network with the local seismic array at Coso maintained by the Navy Geothermal Program office.
2.4.4.1.2 Physical Properties of Rocks in the Geothermal Field

A necessary step in the preparations for the stimulation experiment in well 46A-19RD is to characterize the physical properties and strength of Coso reservoir rocks and use this information to create a comprehensive geomechanical model. Thus, we designed a series of experiments to measure the elastic and seismic properties and failure behavior of representative rock types obtained from core at reservoir depths from the East Flank of the Coso geothermal field. Unconfined compressive failure at the borehole wall is highly dependent on rock strength and is critical to measuring stress in situ based on the width of borehole breakouts visible in borehole image logs acquired with the new ABI85 High Temperature Borehole Televiewer (e.g., Davatzes and Hickman, 2006). These experiments were carried out at the USGS Rock Mechanics Laboratory and are compiled in an USGS Open-File Report in preparation by Morrow and Lockner (2006; copy available on request).

Constraint on Stress Magnitudes at Depth Requires Rock Properties

Borehole breakouts occur where the stress concentration at the borehole wall exceeds the unconfined compressive strength ($C_0$) of the rock (Moos and Zoback, 1990). Thus, the presence or absence of breakouts and their widths can be used to constrain the stress state along a borehole if $C_0$ is known (Moos and Zoback, 1990; Peska and Zoback, 1995). To estimate $C_0$ (Davatzes and Hickman, 2006) we correlate uniaxial and triaxial measurements of compressive strength on rocks representative of the Coso Geothermal Field with laboratory measurements of $V_P$ on the same samples at high confining pressures (TerraTek, 2004; Morrow and Lockner, 2006, summarized below, see also Appendix A for tabulated data). This provides a practical means of estimating $C_0$ from velocity logs obtained from wells within the geothermal field. Our work in conjunction with the work by Annor and Jackson (1987) currently provide the most complete and readily available measurements of $C_0$ and $V_P$ in granitoid rocks acquired by comparable high quality methods. Initial application of this methodology to the East Flank of the geothermal field was presented in Davatzes and Hickman (2006).

The material below principally reports the combined findings of the USGS rock mechanics study on cores from Coso well 34-9RD2 (Morrow and Lockner, 2006) and data obtained earlier on core from Coso well 64-16 (TerraTek, 2004). This report is not intended to exhaustively review these studies, but rather to highlight results most relevant to determining the in-situ state of stress at Coso and its relationship to faults and fractures. Therefore for detailed discussions of procedures, calculations, and data please refer to these other publications.

Both the TerraTek and USGS measurements were collected from sub-cored cylindrical samples 2.54 cm in diameter and 5.59 cm long taken from the interior of the core samples. Although the TerraTek measurements were conducted on cores from the relatively shallow depths in well 64-16, the new USGS measurements were conducted on cores from well 34-9RD2 and are the deepest cores recovered at Coso to date. Thus, the 34-9RD2 samples were recovered from the geothermal reservoir at confining pressures and temperatures similar to those expected in the planned 46A-19RD stimulation experiment. Specifically, the vertical stress was approximately ~66.43 MPa where the weakly foliated granodiorite was collected at a depth of 2562.45 m MD,
and ~67.83 MPa where the slightly altered diorite with healed fractures was collected at a depth of 2430.48 m MD (Figure 2). In both cases temperatures exceeded 290°C.

Core from well 34-9RD2

Figure 2: Core obtained from well 34-9RD2. These samples were sub-cored for 2.54 cm diameter by 5.1 cm long cylindrical samples for the rock deformation experiments.

Porosity and Density
Pore space was determined by measuring the sample volume in conjunction with the dry and wet mass of the samples (see Morrow and Lockner, 2006, for details). This process determines the volume of connected porosity in the sample. Igneous rocks from the East Flank of the geothermal field (Appendix A: Table 1) generally demonstrate small volumes of connected pore space in the rock matrix (Figure 3, Appendix A: Table 4). These measured porosities are consistent with fluid flow and storage localized in fractures zones and faults.
Figure 3: Grain density and connected pore volume measured in granodiorite and diorite core samples from well 34-9RD2 and hornblende-biotite-quartz diorite and biotite granodiorite core samples from well 64-16. Data presented in Table 4.

**Rock Strength**

Results from three measures of rock strength are presented in this section: (1) the peak differential stress sustained by intact samples at a range of confining pressure, (2) the internal friction and cohesion defined by a linear failure envelope, (3) the coefficient of sliding friction on a fresh fracture surface.

Dry samples were loaded to failure at different confining pressures (Figures 4a and b, Appendix A: Table 5) that ranged from unconfined (uniaxial loading) to fifty percent greater than the expected confining pressure at the ~3,048 m (~10,000 ft) stimulation depth planned for well 46A-19RD (Appendix A: Tables 2 and 3). This procedure reveals three critical pieces of information: the peak stress at different confining pressures, the orientation of the failure plane, and the residual strength (sliding friction) after failure. TerraTek (2004) demonstrated that the compressive strength of granitic rocks from the East Flank is largely insensitive to temperature approaching reservoir conditions by conducting experiments at room temperature and 200°C (see pages 24 and 25 therein). Thus, for simplicity all other experiments were typically run at room temperature.
Figure 4a: Differential stress as a function of axial displacement for granodiorite sampled at 8406 ft MD in well 34-9RD2 (Morrow and Lockner, 2006).

Figure 4b: Differential stress as a function of axial displacement for altered diorite sampled at 7974 ft MD in well 34-9RD2 (Morrow and Lockner, 2006).

The relationship between shear stress, normal stress, and the orientation of the failure surface in both the granodiorite (Figure 5a) and the diorite (Figure 5b) define a failure envelope on Mohr diagrams (see Jaeger and Cook, 1979). The diameter of each circle defines the differential stress at failure (i.e., rock strength) for a range of confining pressures, \(P_C\). The failure envelope is defined by a fit to the ratio of shear to normal traction acting on the newly formed fault plane at failure (red-brown dots in Figures 5a and b) and tangent to the Mohr circles. The slope of this line is the coefficient of internal friction, \(\mu_i\), (in this case 1.32) whereas the y-intercept defines the cohesion of the rock (see Appendix A: Table 6). A comparison between Morrow and
Lockner (2006) and TerraTek (2004) shows consistent measurements of the coefficient of internal friction within a small range typical for the granodiorite samples.

The diorite samples show a greater range in measured $\mu_i$ (Appendix A: Table 6), ranging from 0.787 to 1.29. The USGS measurements show two different potential fits (Figure 5b): an upper value of 1.29, which is consistent with typical $\mu_i$ for intact granitic rocks (Lockner and Byerlee, 1993; Lockner 1998), and a lower value of 0.94. The lower range of $\mu_i$ in the USGS tests and in
the TerraTek results (see Appendix A: Table 6) might be explained by micro-crack damage induced by stress relief or thermal cracking in the cores or potentially by chemical alteration. Since these values clearly represent the real strength of diorites in the Coso region, an average value probably best represents the likely \( \mu_i \) encountered in dioritic rocks from Coso.

The peak differential stress at failure as a function of confining pressure measured in the USGS analyses is consistent with the previous analyses from TerraTek (Figure 6). The linear fit to the peak differential stress defines the failure of intact rock at different confining pressures. In conjunction with borehole image, velocity and density logs and a hydraulic fracturing stress test to be acquired later this year, these measurements will be used in analyses of breakout occurrence and width to constrain *in-situ* stress magnitudes from well 46A-19RD. The four rock types studied probably span the failure behavior of rocks with little to minor alteration in the geothermal field.

![Figure 6: Peak differential stress and linear regressions defining the compressive rock strength as a function of confining pressure from wells 34-9RD2 (USGS) and 64-16 (TerraTek).](image)

The coefficient of sliding friction can be determined by calculating the ratio of shear to effective normal stress on the newly formed fault after failure has occurred and the fault is slipping at approximately constant shear stress (Figure 7). Both the internal and the sliding coefficients of friction are approximately in the upper range expected for granitic rocks (Byerlee, 1978; Lockner and Beeler, 2002). Note that the coefficients of sliding friction reported here were measured on freshly broken samples that slipped less than 10 mm.
Figure 7: Residual (or sliding) friction was measured by calculating the shear and normal tractions on the failure surface in the deformed samples (Morrow and Lockner, 2006). Typical ranges for granite are indicated (Byerlee, 1978).

Seismic velocity
P-wave velocity, $V_P$, of samples as a function of confining pressure (loading cycle only) was measured from two samples of granodiorite and two samples of slightly altered and healed diorite (Figure 8, Appendix A: Table 7). Increased confining pressure produced a rapid rise in $V_P$, which is assumed to result from the closure of microcracks at higher confining pressures. The four measurements for each sample type at ~52.1 MPa and 78.2 MPa show little change in $V_P$, thus representative in situ values for each rock type are calculated by averaging the four measurements of these measurements respectively.

Figure 8: $P$-wave velocity, $V_P$, of samples as a function of confining pressure (loading cycle only). Two samples, annotated 1 and 2, of each rock type were run.

Elastic Moduli
Poisson’s ratio and Young’s modulus were determined by measuring axial and transverse strain in the samples during cyclic loading (see Morrow and Lockner, 2006, and TerraTek, 2004). The
unloading phase of the TerraTek data typically showed slightly lower Young’s modulus than in the loading phases, possibly suggesting damage to the samples during loading.

Results of these analyses are compiled in Figure 9 and compiled in Appendix A, Table 8. For simplicity, and because the values were similar, the moduli calculated during the loading, unloading, and subsequent loading phases were averaged. It is likely that the unloading phase provides the most reliable results because it is unaffected by compaction or crack closure which are most likely during the initial loading phase. Therefore, during this averaging the unloading phase was given twice the weight of the loading phase. For all these samples, Poisson’s ratio is generally within the expected range for granites (e.g., Jaeger and Cook, 1979). Young’s modulus is largely in the upper range expected for granites with the exception of the Diorite from 34-9RD2, which is substantially stiffer.

![Figure 9: Measurements of Poisson’s ratio and Young’s modulus. The range of typical values of Young’s modulus in granites are stippled.](image)

2.4.4.1.3 Stress Measurements
Details of the stress state that these faults are subjected to have been revealed through the analysis of borehole image data and hydraulic fracturing stress measurements (Geomechanics International, 2003; Sheridan and Hickman, 2004; Davatzes and Hickman, 2005) and inversion of focal mechanism data for the principal stress axes (Feng and Lees, 1998) and incremental strain axes (Unruh et al., 2002). In this section, we reanalyze some of these earlier results and
present new results and analyses from wells 34-9RD2 and 58A-10 incorporating the new laboratory mechanical data presented above. The locations of these wells are shown in Figure 1.

**Orientation of principal stresses from borehole image logs**

Concentration of tectonic stress around the free surface of a borehole induces both tensile and compressive failure of the rock adjacent to the borehole wall as well as immediately ahead of the drill bit. Field studies have demonstrated that these induced structures reliably record the orientations of the horizontal principal stress axes (see Moos and Zoback, 1990; Zoback et al., 2003; Davatzes and Hickman, 2005a). Three types of drilling-induce structures are recognized: (1) breakouts, (2) tensile fractures and (3) petal-centerline fractures (see Davatzes and Hickman, 2005a for details). Breakouts are patches of the borehole wall that undergo compressive failure and occur in pairs oriented along the minimum horizontal principal stress ($S_{h\text{min}}$) azimuth (Figure 10a). The width of failure corresponds to the region of the borehole wall over which the stress concentrated around the borehole exceeds the unconfined rock strength, $C_0$ (Figure 10b). In contrast, tensile failure of the borehole wall or ahead of the drill bit produces pairs of tensile fractures (Figure 10a) and petal-centerline fractures (Appendix B), respectively, that strike along the orientation of maximum horizontal principal stress ($S_{h\text{max}}$). These structures can be identified and their azimuthal orientations measured from oriented images of the borehole wall reflectivity or micro-resistivity, providing a means to infer the direction of the horizontal principal stress axes. Tensile fractures in the borehole wall occur where the stress concentration around the free surface of the borehole wall and thermal stress due to cooling of the borehole wall produce a tensile “hoop” (or circumferential) stress that exceeds the tensile strength of the rock (Figure 10b). Petal-centerline fractures form due the complex stress concentration below the floor of the borehole as it is drilled. Characteristics of these drilling-induced structures and the stresses that produce them are extensively discussed in Appendix B.

In the CGF, image logs have been obtained with the ABI85 High Temperature Borehole Televiewer (ABI85), Formation Micro Imager (FMI), Hot Hole Formation Micro Scanner (FMS), and Electrical Micro-Imager (EMI) in the East Flank and Coso Wash areas. These logs were checked against borehole deviation surveys and other overlapping image logs to verify accurate image orientations. Borehole deviation over the interpreted intervals range from 3º to 15º which allowed us to neglect corrections required for highly deviated boreholes (Peska and Zoback, 1995). Following the method of Davatzes and Hickman (2005a) the orientation of $S_{h\text{min}}$ was determined from the average of pairs of petal-centerline fractures or tensile cracks. Thus, tensile fractures of either kind were only picked when they occurred as pairs. Mean orientations of $S_{h\text{min}}$ are calculated by averaging the orientation of induced structures weighted by their cumulative lengths. Each type of structure was given equal value in this analysis.
Analyses of image logs acquired in 34-9RD2 and 58A-10 reveal extensive suites of drilling-induced petal-centerline fractures, tensile borehole wall fractures, and to a lesser extent borehole wall breakouts (Davatzes and Hickman, 2006; Rose et al., 2006). No breakouts were observed in the East Flank well 34-9RD2 (Davatzes and Hickman, 2005a, 2006), which is similar to the analysis of nearby well 38C-9 in which only one breakout was seen (Sheridan and Hickman, 2004). However, abundant tensile fractures and petal centerline fractures in well 34-9RD2 indicate that the dominant direction of $S_{h\text{min}}$ is $099^\circ \pm 18^\circ$, with a subsidiary $S_{h\text{min}}$ orientation with limited vertical extent of $176^\circ \pm 15^\circ$ (Figure 1b). In Coso Wash well 58A-10, breakouts are more prevalent but are narrow and shallow. Overall, they represent a small percentage of the total length of induced structures. Orientations of these breakouts together with tensile wall fractures and petal-centerline fractures in well 58A-10 indicated that $S_{h\text{min}}$ is oriented along an azimuth of $108^\circ \pm 15^\circ$ (Figure 1b). Rotations of up to $70^\circ$ from the mean $S_{h\text{min}}$ orientation are also recorded in this well (Davatzes and Hickman, 2005a, 2006).

**2.4.4.1.4 Stress Magnitudes in the East Flank and Coso Wash**

We used two main techniques to determine the magnitude of $S_{h\text{min}}$ and $S_{H\text{max}}$ in the East Flank. The magnitude of $S_{h\text{min}}$ was determined from a hydraulic fracturing stress test conducted previously in well 38C-9 (Sheridan and Hickman, 2004) and a new test conducted in well 34-9RD2 in February 2005 (Davatzes and Hickman, 2006). In addition, upper bounds on the magnitudes of $S_{H\text{max}}$ were obtained through borehole failure analyses using the new geomechanical data presented above and based upon the absence of breakouts in wells 34-9RD2 and 38C-9 in the East Flank, and the presence (and width) of breakouts seen in well 58A-10. In the subsequent text we combine the results from these two wells to develop a revised, integrated stress model for the East Flank.

**Hydraulic Fracturing Measurements in Wells 38C-9 and 34-9RD2**

Two measurements of $S_{h\text{min}}$ were obtained by conducting hydraulic fracturing experiments as part of the EGS project in the East Flank of the Geothermal Field. The details of these experiments are presented in Sheridan and Hickman (2004) at a depth of 1,128.7 m TVD below ground level (GL) in well 38C-9 and in Davatzes and Hickman (2006) at a depth of 2,382.6 m TVD below GL (Table 1) in well 34-9RD2. As done in other geothermal wells (see Hickman et al., 1998), following cementation of the casing, a pilot hole was drilled out the bottom of the well in which to conduct the hydraulic fracture test. Pressures and flow rates were measured at the surface in conjunction with a high accuracy, pressure-compensated quartz pressure gauge suspended in the borehole just above the injection interval. Following Hickman and Zoback (1983) and Hickman et al (1989), $S_{h\text{min}}$ was determined from the instantaneous shut in pressure (ISIP) obtained from repeated pressurization cycles during the mini-hydraulic fracturing experiment (details presented in Davatzes and Hickman, 2006; Rose et al., 2006). The shallower hydraulic fracturing experiment in 38C-9 showed that the magnitude of $S_{h\text{min}}$ at 128.7 m TVD...
is 18.2±0.5 MPa whereas the deeper experiment in nearby well 34.9RD2 showed that the magnitude of $S_{shmin}$ at 2382.6 m TVD is 38.9±1.4 MPa (Figure 11; Table 1).

**Table 1:** Case stress model (Optimal conditions for Breakout (BO) formation between drilling and image logging)

<table>
<thead>
<tr>
<th>Data Source</th>
<th>Deviation Log</th>
<th>TPS log</th>
<th>Sonic Log</th>
<th>Strength model</th>
<th>Image log</th>
<th>Density log</th>
<th>Min. hydrofrac</th>
<th>Calc. from BO analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well</td>
<td>Measured Depth (m) below GL</td>
<td>Deviation</td>
<td>Derivation</td>
<td>True Vertical Depth (m) TVD</td>
<td>Mud Pressure (psi)</td>
<td>Flow Pressure (psi)</td>
<td>Ultimate Compressive Strength (psi)</td>
<td>Breakout</td>
</tr>
<tr>
<td>3BC-9</td>
<td>1,334</td>
<td>340</td>
<td>6.2</td>
<td>1,283</td>
<td>11.4*</td>
<td>4.7*</td>
<td>4.34*</td>
<td>188.85</td>
</tr>
<tr>
<td>34.9RD2</td>
<td>2,405</td>
<td>313</td>
<td>11</td>
<td>2,382</td>
<td>23.5*</td>
<td>7.6*</td>
<td>5.3*</td>
<td>192.16</td>
</tr>
<tr>
<td>S8A-10</td>
<td>2,331</td>
<td>331</td>
<td>4.2</td>
<td>2,382</td>
<td>19.2*</td>
<td>19.2*</td>
<td>5.9*</td>
<td>204.90</td>
</tr>
</tbody>
</table>

Parameters common to all analyses:
- $\mu_e = 0.55$ (coefficient of internal friction) which is an average calculated using the high and low values.
- $S_{shmin}$ calculated from the shear strength of the rock and the overburden pressure.

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Deviation Log</th>
<th>TPS log</th>
<th>Sonic Log</th>
<th>Strength model</th>
<th>Image log</th>
<th>Density log</th>
<th>Min. hydrofrac</th>
<th>Calc. from BO analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well</td>
<td>Measured Depth (m) below GL</td>
<td>Deviation</td>
<td>Derivation</td>
<td>True Vertical Depth (m) TVD</td>
<td>Mud Pressure (psi)</td>
<td>Flow Pressure (psi)</td>
<td>Ultimate Compressive Strength (psi)</td>
<td>Breakout</td>
</tr>
<tr>
<td>3BC-9</td>
<td>1,334</td>
<td>340</td>
<td>6.2</td>
<td>1,283</td>
<td>11.4*</td>
<td>4.7*</td>
<td>4.34*</td>
<td>188.85</td>
</tr>
<tr>
<td>34.9RD2</td>
<td>2,405</td>
<td>313</td>
<td>11</td>
<td>2,382</td>
<td>23.5*</td>
<td>7.6*</td>
<td>5.3*</td>
<td>192.16</td>
</tr>
<tr>
<td>S8A-10</td>
<td>2,331</td>
<td>331</td>
<td>4.2</td>
<td>2,382</td>
<td>19.2*</td>
<td>19.2*</td>
<td>5.9*</td>
<td>204.90</td>
</tr>
</tbody>
</table>

Estimated $S_{shmin}$ is maximum stress at the wellbore (i.e., most critical to breakout formation) as determined from known well data and standing real-time borehole pressure.

Parameters calculated from the following equations:
- $S_{shmin} = \mu_e(\sigma_h + \sigma_v)$
- $\sigma_h = \sigma_v = \mu_e(\sigma_h + \sigma_v)$
- $\sigma_h = \sigma_v = \mu_e(\sigma_h + \sigma_v)$

$\mu_e = 0.35$ (coefficient of internal friction) which is an average calculated using the high and low values.

Parameters common to all analyses:
- $\mu_e = 0.55$ (coefficient of internal friction) which is an average calculated using the high and low values.

$S_{shmin}$ calculated from the shear strength of the rock and the overburden pressure.

**Table 1:** Case stress model (Optimal conditions for Breakout (BO) formation between drilling and image logging)
Stress Magnitudes [MPa]

Depth [m TVD below GL]

$P_p$ and failure envelopes for surface hydrostat (pre-production)

- $S_{h_{\text{min}}}$ Well 38C-9 = 18.24±0.53 MPa (2.645±77 psi)
- $S_{h_{\text{min}}}$ Well 34-9RD2 = 38.85±1.38 MPa (5635±200 psi)

- $P_i$ integrated from the temperature distribution in 38C-9
- $P_i$ integrated from the temperature distribution in 34-9RD2
- $S_v$ calculated from avg. values for basin fill and crystalline basement

- $S_{h_{\text{max}}}$ Upper Bound
- BO Breakout in 38C-9
  - Optimal $S_{h_{\text{min}}}$ for normal faulting from $S_v$
  - Optimal $S_{h_{\text{max}}}$ for strike slip faulting from measured $S_{h_{\text{min}}}$
**Figure 11:** Stress magnitudes for the East Flank derived from measurements in wells 38C-9 (Sheridan and Hickman, 2004) and 34-9RD2 (locations in Figure 1) (results summarized in Rose et al., 2006). The least horizontal principal stress ($S_{hmin}$) was measured using mini-hydraulic fracturing tests at 1128.7 m total vertical depth (TVD) in well 38C-9 (Sheridan and Hickman, 2004) and at 2382.6 m TVD in well 34-9RD2 (Davatzes and Hickman, 2006). The depth extent of image logs acquired in the two wells is shown by vertical lines, with the EMI log obtained in 38C-9 and the FMS log obtained in 34-9RD2. The symbol “BO” denotes the sole breakout observed in these two wells, which was seen at a depth of 1956.5 m in well 38C-9. Upper bounds (with error bars) to the greatest horizontal principal stress ($S_{hmax}$) were obtained assuming that $P_f$ used in calculating optimal $S_{hmin}$ and $S_{hmax}$ in frictional faulting analyses was derived from well 38C-9 (Table 2). These are 83.27±7.3 MPa and 108.16±0.69 MPa for the shallow and deep mini-hydraulic fracturing test depths respectively. Dashed orange lines indicate the range of $S_{hmin}$ magnitudes at which normal faulting would be expected given the calculated vertical stress ($S_v$) for coefficients of friction of 0.6, 0.8, 1.0 (see text). Red dashed lines indicate the range of $S_{hmax}$ where strike-slip faulting would be expected for these same friction values assuming that $S_{hmin}$ increases linearly with depth and passes through the values of $S_{hmin}$ measured in these two wells, as shown by the dashed black line. Undisturbed formation pore pressure ($P_f$) was calculated assuming that the pre-production water table was in hydrostatic equilibrium with the surface under present-day thermal conditions. $P_f$ used in calculating optimal $S_{hmin}$ and $S_{hmax}$ in frictional faulting analyses was derived from well 38C-9 (Table 2).

We calculated the vertical stress ($S_v$) using a geophysical density log run in well 34-9RD2 at depths of 1100.0-1980.3 m MD and making the assumption that the average density from this log (2.65 gm/cm$^3$) applied throughout the entire well and was appropriate for granitic rocks in East Flank wells in general. This simplification is a reasonable based upon the uniform lithology penetrated by these wells (Kovac et al., 2005). It is worth noting that this density is consistent with lab measurements on diorites from 34-9RD2 (Morrow and Lockner, 2006), which is one of the predominant lithologies encountered in the East Flank wells. This density is below the high values measured for granodiorite (e.g., Figure 2). However, those high densities probably only represent the upper end of density for pristine, unaltered or un-fractured rocks which are not representative of the geothermal field in general. The large depth interval averaged also helps insufce the average is representative as it will necessarily account for local variability. In accordance with the Coulomb failure criterion, frictional failure (i.e., normal faulting) would then occur at a critical magnitude of $S_{hmin}$ given by (Jaeger and Cook, 1979):  

$$S_{hmin}^{crit} = (S_v - P_f) / [(\mu^2 + 1)^{1/2} + \mu]^2 + P_f$$

where $\mu$ is the coefficient of friction of preexisting faults. It is assumed here that $\mu$ ranges from 0.6 to 1.0, in accord with laboratory sliding experiments on a variety of rock types (Byerlee, 1978). Recent lab measurements indicate that $\mu$ is approximately 0.8 in fresh fracture surface in diorite typical of the geothermal field.

Estimates of undisturbed (i.e., preproduction) formation fluid pressure ($P_f$) for use in Equation 1 were obtained assuming that $P_f$ was in hydrostatic equilibrium with a water table at the surface. This is consistent with positive well-head pressures recorded prior to significant production in the East Flank, such as in well 64-16 (Paul Spielman, pers. comm. 2003; Joe Moore, pers. comm. 2004). To take account of the high geothermal gradients, the variation of fluid pressure with depth was determined by integrating experimentally derived pure water density as a function of pressure and temperature as appropriate to ambient geothermal conditions, and including a small correction for total dissolved solids (Keenan et al., 1978) (Table 2). In this analysis we assumed that modern measurements of temperature reliably represent pre-production thermal conditions,
which is reasonable given the limited injection of cold fluid into the East Flank in the vicinity of 34-9RD2 and 38C-9 and since draw-down alone should have only a small impact on thermal structure. In this manner, we calculated the range of $S_{h\text{min}}$ magnitudes at which normal faulting would be expected along optimally oriented faults (Figure 11).

The measurements of $S_{h\text{min}}$ in wells 34-9RD2 and nearby well 38C-9 define a gradient of $S_{h\text{min}}$ in the East Flank (Figure 11). Rearranging equation 1 to solve for $\mu$, the gradients in $P_f$, $S_V$ and $S_{h\text{min}}$ suggest that optimally oriented faults with $\mu > 0.44$ should be stable if normal faulting predominates and $S_{H\text{max}}$ is not considered in the East Flank.

### Table 2: East Flank Fluid Pressure and Vertical Stress Gradients from wells 38C-9 and 34-9RD2

<table>
<thead>
<tr>
<th>Depth [m TVD GL]</th>
<th>$T_a^{38\text{C}-9}$ [deg C]</th>
<th>$T_a^{34\text{-9RD2}}$ [deg C]</th>
<th>$S_V^b$ [g/cc]</th>
<th>$P_{f*}^{c}$ 38C-9 [MPa]</th>
<th>$P_{f*}^{c}$ 38C-9 [MPa]</th>
<th>$P_{f*}^{c}$ 34-9RD2 [MPa]</th>
<th>$P_{f*}^{c}$ 34-9RD2 [MPa]</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>60</td>
<td>125</td>
<td>0.1</td>
<td>0.957</td>
<td>0.1</td>
<td>0.9382</td>
<td>0.1</td>
</tr>
<tr>
<td>243.8</td>
<td>143</td>
<td>126</td>
<td>6.3</td>
<td>0.921</td>
<td>2.3</td>
<td>0.9393</td>
<td>2.4</td>
</tr>
<tr>
<td>574.1</td>
<td>---</td>
<td>126</td>
<td>14.9</td>
<td>---</td>
<td>---</td>
<td>0.9103</td>
<td>5.5</td>
</tr>
<tr>
<td>1015.3</td>
<td>---</td>
<td>194</td>
<td>26.4</td>
<td>---</td>
<td>---</td>
<td>0.8787</td>
<td>9.5</td>
</tr>
<tr>
<td>1064.4</td>
<td>154</td>
<td>192</td>
<td>27.7</td>
<td>0.894</td>
<td>9.7</td>
<td>0.8793</td>
<td>10.0</td>
</tr>
<tr>
<td>1128.7</td>
<td>144</td>
<td>193</td>
<td>29.3</td>
<td>0.836</td>
<td>10.3</td>
<td>0.8723</td>
<td>10.6</td>
</tr>
<tr>
<td>1643.0</td>
<td>---</td>
<td>207</td>
<td>42.7</td>
<td>---</td>
<td>---</td>
<td>0.8500</td>
<td>15.1</td>
</tr>
<tr>
<td>1767.8</td>
<td>208</td>
<td>238</td>
<td>45.9</td>
<td>15.9</td>
<td>0.7921</td>
<td>16.2</td>
<td></td>
</tr>
<tr>
<td>2309.1</td>
<td>---</td>
<td>288</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>20.5</td>
</tr>
<tr>
<td>2382.6</td>
<td>260</td>
<td>---</td>
<td>61.9</td>
<td>21.1</td>
<td>---</td>
<td>---</td>
<td></td>
</tr>
<tr>
<td>2817.0</td>
<td>282</td>
<td>---</td>
<td>73.2</td>
<td>24.4</td>
<td>---</td>
<td>---</td>
<td></td>
</tr>
</tbody>
</table>

Footnotes:

* Evaluated at temperature and pressure at the middle depth between this and the next row. Depths evaluated were chosen to bound zones of consistent temperature gradient.

a Temperature survey from (Rose et al., 2006)

b Assume uniform rock density of $\rho = 0.65$ g/cc.

c Corrected for temperature/pressure effects on water density in pure water (using Steam Tables from Keenan et al. (1978)) and including a small density correction for total dissolved solids of 5,000 ppm NaCl by weight, which is typical for Coso reservoir waters (Pers. Com. Joe Moore). Thus $P_{f*}^{c} = P_{f*} * 1.005$, neglecting small changes in the specific volume of the solution due to the addition of the dissolved solids or their possible impact on the equations of state of water.
Bounds on Greatest Horizontal Principal Stress ($S_{Hmax}$)

As noted previously, borehole breakouts occur where the stress concentration at the borehole wall exceeds the unconfined compressive strength ($C_0$) of the rock (Moos and Zoback, 1990). Thus, the presence or absence of breakouts and their widths constrain the stress state along the well if $C_0$ is known. Given that only a single breakout was observed in well 38C-9 (Sheridan and Hickman, 2004) and none were observed in well 34-9RD2 (Davatzes and Hickman, 2006), we used the general absence of breakouts in both wells to determine upper bounds to the magnitude of $S_{Hmax}$. This analysis used $S_{Hmin}$ magnitudes measured in both wells (Figure 11) together with theoretical models for breakout formation in inclined wells based upon the elastic concentration of stresses around a circular borehole (Moos and Zoback, 1990; Peska and Zoback, 1995). This represents an update to previous bounds on $S_{Hmax}$ from the East Flank (Sheridan and Hickman, 2004; Davatzes and Hickman, 2006) using recent laboratory measurements of rock mechanics parameters carried out under the EGS project (TerraTek, 2004; Morrow and Lockner, 2006).

These measurements were conducted on dry hornblende-biotite-quartz diorite (HBQ diorite) from Coso well 64-16 at approximately 2820 ft MD. The use of these data in our analysis is justified since HBQ diorite best represents rocks encountered in wells 38C-9 and 34-9RD2 (Kovac et al., 2005).

To estimate $C_0$ at any given depth we used uniaxial and triaxial measurements of compressive strength on representative rock samples obtained from coring of wells 34-9RD2 and 64-16 (e.g., Figure 12a) to obtain a reference value for $C_0$ (TerraTek, 2004; Morrow and Lockner, 2006) and then used in-situ values of $V_P$ recorded by wireline geophysical logs to extrapolate these values of $C_0$ to in-situ conditions. These values, together with laboratory measurements of $V_P$ on the same samples at confining pressures consistent with the depths of interest at Coso (e.g., Figures 6 and 8; Appendix A: Tables 5 and 7) were then compared to the much larger set of measurements of $C_0$ as a function of $V_P$ from core samples of Lac du Bonnet granite at depths up to 1 km (Annor and Jackson, 1987; Figure 12b). (Annor and Jackson (A&J) currently provide the most complete and readily available measurements of $C_0$ and $V_P$ in granitoid rocks acquired by a single high quality method.) We also include core samples tested from granites in the Desert Peak Geothermal Field, NV (New England Research, 2003) for reference only. To characterize the manner in which $C_0$ varies with $V_P$, we then required that a least squares fit of a straight line to the A&J data pass through $C_0$ determined for the average of the HBQ diorite measured by TerraTek and the altered and healed HB diorite measured at the USGS (Figure 12b) to arrive at the following empirical strength law for the East Flank:

$$C_0 = 113.78 + 15.20(V_P)$$

(2)

where $C_0$ is in MPa and $V_P$ is in km/sec. As noted earlier, USGS and TerraTek measurements were conducted on core samples of representative rock types in the geothermal field. Granodiorite and various diores are the most abundant rock types in well 34-9RD2 identified from cuttings (Kovac et al., 2005). In general the East Flank is dominated by Q-, HB-, and, HBQ-diorites, granites, and granodiorites (Rose et al., 2006). In well 58A-10 the Q- and HB-diorites dominate (Moore et al., 2004). The granodiorite shows very high intrinsic unconfined compressive strength relative to diores which show lower $C_0$. (Figure 6; Appendix A: Table 5) (TerraTek, 2004; Morrow and Lockner, 2006). In generating equation 2, we assume that the
weaker diorites are most likely to host breakouts compared to granodiorites and thus best represent the $C_0$ associated with any breakout occurrence.

The analysis of A&J demonstrates a positive correlation between $V_P$ and $C_0$ that likely reflects their mutual sensitivity to properties such as chemical alteration and microcrack density, which influence both rock strength and wave speed in crystalline rocks. Uncertainty in the model was evaluated by calculating the standard deviation of the data about the mean after removing the slope inferred from the linear least squares regression. The standard deviation to the entire data set is $\pm 18.6$ MPa in $C_0$, which is about 11.5% of the measured value of $C_0$. Since the same physical mechanism need not govern the correlation of $V_P$ with $C_0$ at different velocities, we also examined the uncertainty in the regression by calculating the standard deviation within a moving window 1 km/sec wide and containing at least 10 data points (green region in Figure 12b). To estimate the uncertainty of $C_0$ calculated from velocities outside the range of A&J data we used the standard deviation calculated from the closest 1 km/sec bin (Table 1).

Repeatability in typical laboratory measurements of rock strength is about 2-5% (David Lockner, pers. comm. 2006). Thus, the scatter about the A&J regression implies ±5-8% real heterogeneity in $C_0$ that is not captured by measurements of $V_P$. We thus interpret most of the scatter about the linear fit to the A&J data to represent natural heterogeneity in the strength inherent in a volume of rock with similar mineralogy and geologic history, which should provide a reasonable estimate of the uncertainty in rock strength to be expected at Coso. Accordingly, we have propagated this one standard deviation uncertainty through our Coso stress analysis as representative of real heterogeneity in $C_0$ not captured by $V_P$.

We then applied Equation 2 to in-situ measurements of $V_P$ from wireline logs to estimate $C_0$ as a function of depth in wells 34-9RD2 and 58A-10 (Figure 12c). This analysis was performed on the raw $V_P$ data as well as data that had been subjected to Gaussian smoothing within a 2 m window. The smoothed values for $C_0$ were used in our stress model, as we believe they probably best represent bulk properties of the host rock at the length scales over which breakouts were observed. Estimated values of $C_0$ range from ~150 to ~235 MPa in the raw data and ~160 to ~233 MPa in the smoothed data, probably reflecting variations in rock type and damage as well as hydrothermal alteration along the borehole (Figure 12c), as documented by Kovac et al. (2005). Uncertainty in $C_0$ is indicated by the error bars in Figure 12c which are given by the superposition of ±1 standard deviation in the A&J data at the appropriate value of $V_P$ (Figure 12 b; as described above) and ±1 standard deviation in $V_P$ itself over the depth range of interest. As no $V_P$ logs are available for well 38C-9, we used the average strength from the upper 150 m of nearby well 34-9RD2 (Figure 12c) to estimate $C_0$ and thus $S_{Hmax}$ for that well. We also conservatively estimated the error of this approximation as the superposition of one standard deviation in the A&J data and $V_P$ over this interval to reflect our limited constraints on rock strength and the natural variability expected at this depth range. In well 38C-9, because $C_0$ is not directly pinned to an in-situ measurement of $V_P$, the constraint estimated for $S_{Hmax}$ is less reliable than the estimates in the other wells. At the depths of interest, the values of $C_0$ used to constrain $S_{Hmax}$ in wells 38C-9 and 34-9RD2 were 188.82±27.40 MPa and 192.16±18.67 MPa, respectively; in 58A-10 $C_0$ was 204.90±22.26 (Table 1).
Figure 12: (a) Mohr diagram showing compressive strengths determined on 6 samples of dry hornblende-biotite-quartz diorite (HBQ diorite) from Coso well 64-16 at approximately 859.5 m MD (TerraTek, 2004). The red circle represents an unconfined compressive strength ($C_0$) test, whereas the other circles represent triaxial compressive strength tests at a variety of confining pressures. The Mohr-Coulomb failure criterion for this rock (red line tangent to these circles) is very well-constrained, with cohesion of 48.5 MPa and internal friction angle of 38.2°. Although most tests were conducted at room temperature, one test at 200°C indicates that short-term compressive strength for these rocks is relatively insensitive to temperature. (b) Unconfined compressive strength ($C_0$) as a function of P-wave velocity ($V_p$) from tests on Lac du Bonnet granite (Annor and Jackson, 1987) and the Coso core samples. Linear least squares best fit to the Annor and Jackson data (blue dashed line) was forced to coincide with the strength and $V_p$ measurements made on the average of the Coso hornblende and biotite-rich diorites from 64-16 and the USGS measurements of slightly altered HB diorite (red dashed line, Equation 1 in the text). Please note that a single, anomalously low value of $C_0$ at high $V_p$ was excluded from the analysis as this outlier had a disproportionate impact on the strength model. Estimates of error are noted in the Figure. (c) Raw and smoothed $V_p$ log of well 34-9RD2 on the left and 58A-10 on the right and estimated variation of $C_0$ with depth using Equation 2.

In addition to $C_0$ and the magnitude of $S_{\text{hmin}}$, several other parameters must be estimated or measured to constrain $S_{\text{hmax}}$ (Peska and Zoback, 1996) and are presented in Table 1. Borehole deviation angle and azimuth were determined from directional surveys and the local azimuths of $S_{\text{hmin}}$ were determined directly from observations of wellbore failure (Sheridan and Hickman, 2004; Davatzes and Hickman 2006). In general, breakouts visible in image logs form under the most favorable conditions between the time of drilling and the time of logging. Mud pressures, $P_m$, in excess of formation fluid pressure, $P_f$, minimize the compressive hoop stress at the borehole wall and inhibit breakout formation (Figure 10b). Current (i.e., post-production) fluid pressures – as opposed to pre-production values used in our geologic failure analysis (c.f., Figure 11) – are needed to calculate the concentration of effective stresses around the borehole and were estimated from temperature/pressure surveys conducted in all three wells during static (shut in) conditions, as described in Table 1. Minimum mud pressures experienced by logged intervals of each well prior to image logging were determined from measured borehole fluid levels and densities or from TPS surveys conducted after drilling was completed. In addition, since breakouts can form either immediately above the drill bit during drilling when little cooling has occurred (i.e., shallow skin depth) or following post-drilling thermal re-equilibration when tensile hoop stress induced by cooling have subsided, thermal stresses should have little effect on breakout occurrence and width. Thus, thermal stresses are not included in the following stress analyses. Finally, consistent with the assumption in the strength model that breakouts will tend to form in the weaker diorites, in this analysis we used a coefficient of internal friction, $\mu$, of 0.95, which is the average value determined for the diorites by the USGS (Morrow and Lockner, 2006) and TerraTek (2004), as discussed above (see Figure 5b).

Upper bounds on $S_{\text{hmax}}$ in 38C-9 and 34-9RD2 were calculated from the absence of breakouts in these wells and consistent with other wells in the East Flank (Sheridan and Hickman, 2004) Our calculations suggest that the upper bounds on $S_{\text{hmax}}$ in proximity to these two wells are 85.4 (+11.7, -7.0) at 1,128.7 m TVD and 117.0 (+6.6,-6.5) at 2,382.6 m TVD (Figure 11; Table 1).

Unlike wells 34-9RD2 and 38C-9 inside the geothermal field, well 58A-10 just east of the geothermal field in Coso Wash (Figure 1a) hosts abundant shallow borehole wall breakouts that tend to occur over discrete depth intervals (i.e., clusters; see Figure 13a). The analysis of cuttings recorded in the mud log indicates that the region of most abundant breakouts also appears to
correlate with diorite dominated units. This is consistent with the assumptions used to develop the empirical relationship between $V_P$ and $C_0$, as discussed above. In the analysis that follows, we estimate the magnitude of $S_{H_{\text{max}}}$ in well 58A-10 at a depth corresponding to one of these breakout clusters (2331.7 to 2313.4), which is also close to the depth at which $S_{h_{\text{min}}}$ was measured with a mini-hydraulic fracturing test in 34-9RD2.

The mean width of the breakout cluster at this depth is 33.0° (Figure 13a, cluster used is indicated by box). In the breakout analysis for 58A-10, we assume hydrostatic equilibrium between $P_m$ and $P_f$ in the near-wellbore environment, with $P_m$ as measured directly by static TPS logs obtained after long periods of shut-in prior to image logging. This corresponds to a fluid level at 274.32 m TVD in the well and a fluid pressure gradient of 9.39 kPa/m. This is the minimum $\Delta P = P_m - P_f = 0$ prior to image logging and thus the most favorable condition for breakout formation. This assumption is also consistent with the abundant positive and negative flow zones indicated by mud losses during drilling and temperature and flow anomalies recorded by repeat TPS logs (Davatzes and Hickman, in prep.), suggesting near pressure equilibration between the borehole and formation fluid pressures. Since smaller magnitudes of $\Delta P$ favor breakout formation, this situation is distinct from the 38C-9 and 34-9RD2 wells and helps to explain why abundant breakouts were only seen in well 58A-10.

$S_V$ in 58A-10 was determined assuming a uniform density of 2.3 g/cc in the sedimentary fill of the Coso Wash down to a depth of 552.6 m TVD and a uniform density of 2.65 g/cc in the underlying crystalline basement, which is consistent with the similarity in basement rock types between the East Flank and Coso Wash. It is worth noting that because the deviation of 58A-10 from the vertical over the depths studied here is less than 4.2°, $S_V$ has minimal impact on the propensity for breakout formation and thus the calculation of $S_{H_{\text{max}}}$ magnitude from breakout width (typically >10° deviations are necessary to produce a significant effect; Peska and Zoback, 1996; Zoback et al., 2003). For completeness we did include the effects of $S_V$ and the 4.2° deviation from vertical in our calculations.

Using $V_P$ logs run in well 58A-10 we calculated $C_0$ (Figure 12c) and then conducted the same kind of analysis as was performed for 34-9RD2 (above) to estimate the magnitude of $S_{H_{\text{max}}}$. Since no hydraulic fracturing tests were conducted in well 58A-10, instead we assumed that $S_{h_{\text{min}}}$ varied with depth in the same manner as measured in the East Flank wells. Thus by linear interpolation we calculated that $S_{H_{\text{max}}}$ is 100.5 (+8.1,-7.9) MPa in the vicinity of 58A-10 from a cluster of breakouts near the depth of the mini-hydraulic fracturing test in 34-9RD2 (Figure 13b). We also estimated the sensitivity of this analysis to our estimate of $S_{h_{\text{min}}}$, which is critical for determining $S_{H_{\text{max}}}$ from breakout width. If we permit the magnitude of $S_{h_{\text{min}}}$ to vary within the permissible range from $P_P$ to $S_V$ we find that the $S_{H_{\text{max}}}$ might vary by an additional 10 MPa over that calculated (above) solely from the estimated uncertainty in $C_0$. However, it is highly unlikely that $S_{h_{\text{min}}}$ can vary to these extremes. No catastrophic mud losses have occurred during drilling operations at Coso as would be expected if $S_{h_{\text{min}}}$ were close to $P_f$ in magnitude. Furthermore, a transitional strike-slip to reverse faulting stress regime – as implied if $S_{h_{\text{min}}}$ were close to $S_V$ in magnitude – is extremely unlikely due to active normal faulting and extensional stress in the immediate vicinity (Feng and Lees, 1999; Unruh et al., 2001; Fialko and Simons, 2001; Wicks et al., 2001; K. Richards-Dinger, pers. comm. 2006). We also note that $S_{h_{\text{min}}}$ is currently within 2.1 MPa, or 5.6%, of the value estimated for pure strike slip faulting wherein $S_{h_{\text{min}}} = (S_V+S_{H_{\text{max}}})/2$.
(Jaeger and Cook, 1979), which is consistent with the overall tectonic model presented by Monastero et al. (2005).

Table 3: Coso Wash Fluid Pressure and Vertical Stress Gradients from 58A-10

<table>
<thead>
<tr>
<th>Depth [m TVD GL]</th>
<th>T [°C]</th>
<th>S [MPa]</th>
<th>ρ [g/cc]</th>
<th>P corr [MPa]</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>32</td>
<td>0.992</td>
<td>0.1</td>
<td></td>
</tr>
<tr>
<td>243.8</td>
<td>51</td>
<td>5.5</td>
<td>2.5</td>
<td></td>
</tr>
<tr>
<td>552.6</td>
<td>92</td>
<td>12.4</td>
<td>5.5</td>
<td></td>
</tr>
<tr>
<td>1064.4</td>
<td>145</td>
<td>25.8</td>
<td>9.25</td>
<td>10.3</td>
</tr>
<tr>
<td>1128.7</td>
<td>149</td>
<td>27.4</td>
<td>9.18</td>
<td>10.9</td>
</tr>
<tr>
<td>1380.0</td>
<td>159</td>
<td>34.0</td>
<td>0.914</td>
<td>13.2</td>
</tr>
<tr>
<td>1767.8</td>
<td>162</td>
<td>44.0</td>
<td>0.911</td>
<td>16.8</td>
</tr>
<tr>
<td>2326.5</td>
<td>171</td>
<td>58.6</td>
<td>0.907</td>
<td>21.89</td>
</tr>
<tr>
<td>2382.6</td>
<td>176</td>
<td>60.0</td>
<td>0.896</td>
<td>22.5</td>
</tr>
<tr>
<td>2817.0</td>
<td>193</td>
<td>71.3</td>
<td>---</td>
<td>26.45</td>
</tr>
</tbody>
</table>

*a* Evaluated at temperature and pressure at the middle depth between this and the next row. Depths evaluated were chosen to bound zones of consistent temperature gradient.

*a* Static temperature from TPS log of 9/18/2001 run ten months following shut in.

*b* Assuming sediment fill with density of 2.3 g/cc to depth of 552.6 m, underlain by crystalline basement with density of 2.65 g/cc.

*c* Corrected for temperature/pressure effects on water density in pure water (using Steam Tables from Keenan et al. (1978)) and including a small density correction for total dissolved solids of 5,000 ppm NaCl by weight, which is typical for Coso reservoir waters (Pers. Com. Joe Moore). Thus $P_{corr} = P_t \times 1.005$, neglecting small changes in the specific volume of the solution due to the addition of the dissolved solids or their possible impact on the equations of state of water.

*Depth of breakout analysis.*

*Depth transition from steeper shallow temperature gradient to more isothermal temperature gradient.*

Scatter in a simple cross-plot of wBO against $V_p$ (not shown here) suggests that error in the estimation of $S_{Hmax}$ might result from one of two sources. 1) Heterogeneity in rock strength that is not mapped by $V_p$: As discussed in relation to Figure 12b above, this source of error is already accounted for in our uncertainty analysis for $C_0$ and, hence, $S_{Hmax}$. 2) Small-scale heterogeneity in stress that violates the assumption of a uniform stress under even such a short depth window: In our estimate of $S_{Hmax}$ magnitude in 58A-10 we assume that stress magnitudes and directions are uniform within the short depth interval of the breakout cluster analyzed and thus that all heterogeneity in breakout width at this depth is due to variations in rock strength. For this reason, and since uncertainties due to variations in rock strength have already been incorporated into our error analysis, we do not explicitly include variations in breakout width in our uncertainties for $S_{Hmax}$. It is important to note that breakouts in the clusters observed in 58A-10 all occur at local minima in $V_p$, supporting our postulate that $V_p$ provides a good constraint on $C_0$ and our assumption that strength heterogeneity is the dominant source of local scatter in breakout occurrence and width. (Future work will include a more complete analysis of this assumption to evaluate possible roles of local stress heterogeneity in controlling breakout width. For example, simple analyses of variations in wBO observed for the breakout cluster analyzed in 58A-10 (Figure 13b inset) indicate that variations in $S_{Hmax}$ on the order of ± 8 MPa at that depth could be indicated if none of the observed variations in wBO were ascribed to variations in rock strength.)
Figure 13: (a) Distribution of breakout width with depth. Note that imaging in the FMI is poor due to limited azimuthal coverage and to extensive damage and alteration of the rock constituting the borehole wall. Therefore the catalogue of breakout occurrence and width is incomplete. (b) Estimated $S_{\text{Hmax}}$ based on breakout width, and estimated $C_0$ (Figure 12) and assuming the same $S_{\text{hmin}}$ gradient and fluid pressure gradient relative to the surface as in 34-9RD2. Distribution of breakout widths for the whole well (blue) and for the cluster analyzed (white) are inset. (c) Sensitivity of $S_{\text{Hmax}}$ to the conditions assumed from 34-9RD2. As discussed in the text, the maximum additional error that could be introduced into the analysis if $S_{\text{hmin}}$ were allowed to vary from $P_f$ to $S_V$ (the greatest possible range) is 10 MPa. Note in Figure c that the $S_{\text{Hmax}}$ value determined for well 58A-10 coincides with the frictional strength measured on fresh rock from Coso well 34-9RD2 (Figure 7; Appendix A, Table 6).

2.4.4.1.5 Discussion

Stress and Strain in Different Regions in and adjacent to the Geothermal Field

We integrated the new analyses from wells 34-9RD2 and 58A-10 (above) with existing analysis conducted by Geomechanics International (2003) after careful quality checking to investigate the variation of stress orientations in the East Flank and Coso Wash. In general, the mean azimuth of $S_{\text{hmin}}$ in wells throughout both areas is $\sim 108^\circ \pm 24^\circ$ (Figure 1b). This orientation is consistent with the N- to NNE-striking normal faults that seismicity and/or geomorphology indicate are currently active (Figure 1a). Inside the East Flank, stress orientations indicate somewhat greater heterogeneity than in Coso Wash. Wells 38A-9, 38C-9, and 34-9RD2 indicate stress orientations more similar to the Coso Wash wells. However, wells 38C-9, 83-16, and the subsidiary mode in 34-9RD2 suggest that $S_{\text{hmin}}$ is oriented approximately NNW-SSE (Sheridan and Hickman, 2004; Davatzes and Hickman, 2006).

Detailed examination of variations in borehole failure orientations with depth reveals numerous localized stress rotations, such as the prominent rotations at about 5100 ft measured depth (MD) in well 34-9RD2 and at 9700 ft MD in well 58A-10 (Davatzes and Hickman, 2006). Our
preliminary modeling of these local rotations in $S_{h_{\text{min}}}$ (not presented here) suggests that they result from slip on faults, indicating active deformation in the crust of the East Flank and adjacent Coso Wash. These stress rotations often occur adjacent to large-aperture faults visible in image logs (e.g., Davatzes and Hickman, 2005) at a variety of wavelengths and with amplitudes of up to $70^\circ$. This suggests ongoing fault slip at a variety of scales consistent with abundant local seismicity over a large range of magnitudes (K. Richards-Dinger, pers. comm. 2006).

A simple comparison of $S_{h_{\text{min}}}$ values from hydraulic fracturing tests in wells 38C-9 (Sheridan and Hickman, 2004) and 34-9RD2 (this study) with the normal faulting failure envelope (Figure 11 and 13) indicates that $S_{h_{\text{min}}}$ in the East Flank at depths of 3,000 to 9,000 ft MD is possible if $\mu$ on optimally oriented normal faults is less than ~0.44. That optimally oriented faults do, indeed, exist in the East Flank is indicated by surface mapping of faults at high angle to $S_{h_{\text{min}}}$ that offset Holocene sediments (e.g., Figure 1) and by analysis of borehole image logs from 38C-9 and a number of nearby wells (Sheridan and Hickman, 2004).

However, an immediate assumption that normal faulting dominates is tempered by the potential influence of $S_{H_{\text{max}}}$. Analysis of stress magnitudes indicates that $S_{H_{\text{max}}}$ in the East Flank at depths of 3,000 to 9,000 ft MD could be significantly in excess of $S_V$ (Figure 11). By applying the same type of frictional failure analysis as was applied for normal faulting to strike-slip failure,

$$S_{H_{\text{max}} \text{crit}} = (S_h - P_f) \left[ (\mu^2 + 1)^{1/2} + \mu \right]^2 + P_f$$

we see that upper bounds to $S_{H_{\text{max}}}$ are equal to or greater than the critical values required for frictional failure on optimally oriented strike-slip faults under pre-production fluid pressure conditions (Figure 11). If the actual values of $S_{H_{\text{max}}}$ are close to these upper bounds, then the East Flank of the CGF is in almost a pure strike-slip faulting regime stress regime. Nonetheless, in the absence of significant breakouts our analysis of $S_{H_{\text{max}}}$ only provides upper bounds—so $S_{H_{\text{max}}}$ could be much smaller and the stress regime in the East Flank could be much closer to transitional between strike-slip and normal faulting.

In contrast, our stress analysis in well 58A-10, immediately to the east of the CGF in Coso Wash, suggests a nearly pure strike-slip faulting stress regime (i.e., $S_V = (S_{h_{\text{min}}} + S_{H_{\text{max}}})/2$) with differential stresses so high that strike-slip failure is favored on well oriented faults with coefficients of friction of $\leq 0.8$ (Figure 13b). It is interesting to note that this is within the range measured in the lab on fresh fracture surfaces from Coso cores (Figure 7). Whereas the proximity of the measured $S_{h_{\text{min}}}$ to failure (requiring only a $\mu$ of 0.44 or lower, see Figure 11) and the presence of young normal faults suggests normal faulting dominates in the East Flank, the relatively large magnitudes of $S_{H_{\text{max}}}$ in Coso Wash and the strike slip faults common in the regions surrounding the geothermal field (Monastero et al., 2005) are consistent with a transitional normal to pure strike-slip faulting system that potentially varies with depth.

In addition to our borehole analyses, several studies have mapped spatial variations in the local state of stress or incremental strain by inversion of spatially clustered populations of earthquake focal mechanisms (Feng and Lees, 1998; Unruh et al., 2002). The orientations of the least principal compressive stress or extension direction predicted by these methods are generally uniform within the geothermal field (Figure 1) and similar to borehole measurements. Due to the
low rates of seismicity, results for Coso Wash are not available for comparison with borehole results. However, stress directions indicated by extensive borehole observations in Coso Wash are consistent with extension accommodated by adjacent N- to NNE-striking faults such as the Coso Wash fault segments (Figure 1b).

More recent earthquake relocations and incremental strain inversions also map an area of extensional strain located over the southern part of the Main Field and extending east and north into the East Flank (Keith Richards-Dinger, pers. comm. 2005). This interpretation is consistent with both the stress and the strain invariants predicted by the previous studies, and with local GPS- and InSAR-based surface displacement vectors which indicate subsidence above the Main Field and East Flank (Fialko and Simons 2000; Wicks et al., 2001; Unruh et al., 2002). Such a strain field favors normal faulting and is characterized by relatively low mean stress, consistent with our observations in the East Flank. This low mean stress is expected to facilitate dilation and increased permeability accompanying fault slip. Thus, the relatively low mean stress predicted by these strain data and inversions for the southern part of the Main Field, where EGS well 46A-19RD is located and where permeability is currently low, is favorable for a successful EGS stimulation. This inferred stress state near 46A-19RD will be tested with a hydraulic fracturing stress measurement and borehole image and other logging planned for 2007.

Implications for Stress on Known faults inside the Coso Geothermal Field
The stress state and resulting tendency for slip on faults in the Coso Geothermal Field was investigated by Davatzes and Hickman (2006) and has been revised in the preceding pages. Four potential models bracket the potential geologic, pre-production stress states in the geothermal field (Figure 14). In each of these models, stress magnitudes are derived from the observations presented in Table 1 and Figures 11 and 13, which correspond to the near isothermal depth intervals associated with the convecting regions of the geothermal reservoir. In this simple 2-D case, the ratios of the effective principal stresses are assumed to be constant with depth and fixed at the values presented in Table 1. Thus any potential for vertical variations in stress ratios, such as due to changing fluid pressure, are ignored. For simplicity, uniform stress ratios and orientations are applied throughout the entire map region, although Figure 1 indicates stress rotations are of interest in even this small area. In the calculations, effective stress magnitudes are normalized to the effective vertical stress and are summarized above each result to facilitate comparison of the models (Figure 14). We suggest that a more complete geomechanical model should be undertaken to investigate these spatial stress variations and their potential relationships to fault interactions and large-scale fluid flow.

The first of these models represents a pure normal faulting case and is primarily presented for reference as it is the least likely scenario given the presence of major strike-slip faults in the Eastern California Shear Zone to the west and east of the CGF. The East Flank scenario is for a transitional normal faulting to strike-slip faulting regime, and considers the possibility that $S_{Hmax} = 99\% S_V$. This scenario allows for both normal faulting and strike-slip faulting, although the differential stresses available to drive faulting (i.e., $S_V - S_{hmin}$ for normal faulting or $S_{Hmax} - S_{hmin}$ for strike-slip faulting) are relatively low (Figures 11 and 13). The Coso Wash case is derived from Figure 13 and the constraints on $S_{Hmax}$ from breakout width as previously discussed. This case produces the highest slip tendency. Of interest in this case, is that although warm compared to typical continental geothermal gradients, Coso Wash is significantly colder than the East
Flank, and thus experiences slightly higher fluid pressures at depth due to higher in-situ fluid densities. In addition, sedimentary cover in Coso Wash reduces the magnitude of $S_V$ at depth. The analysis from Coso Wash provides two key advantages over the analysis from the East Flank. First, the development of breakouts in well 58A-10 allowed us to constrain $S_{H_{\text{max}}}$ with very little uncertainty by extrapolating the hydraulic fracturing experiments from the East Flank and given the admissible range of $S_{h_{\text{min}}}$ in 58A-10, as discussed above. Second, Coso Wash has very limited pressure communication with the actively producing geothermal field (Mike Adams, Steve Bjornstad, Paul Spielman, pers. comm. 2005). Thus it is likely that the stress state in well 58A-10, which is immediately adjacent to the actively producing CGF, best represents the geologic, pre-production stress state.

Unlike the producing geothermal field, Coso Wash lacks significant seismicity despite high differential stresses and relatively high present-day fluid pressure (at least compared to producing wells in the East Flank). This highlights the role of production in inducing micro-seismicity at Coso, which is superimposed on a long-term pattern of ongoing deformation and large-scale faulting in this area (Wicks et al., 2001; Unruh and Streig, 2004; Monastero et al., 2005).

The last case, titled Geologic Best Case, uses the magnitude of $S_{H_{\text{max}}}$ from Coso Wash and applies it to the East Flank and Main Field with $P_f$ appropriate for the higher temperature gradient in this region and $S_V$ reflecting crystalline basement rocks to the surface. The magnitude of $S_{H_{\text{max}}}$ calculated for Coso Wash is compatible with the upper bounds required by the lack of breakouts in the East Flank. This case, like the Coso Wash case, predicts active oblique slip on most of the existing normal faults at coefficients of friction from ~0.4 to ~0.8 consistent with laboratory results on Coso cores (Figure 7; TerraTek, 2004; Morrow and Lockner, 2006). The predicted optimal fault orientation is consistent with known strike slip faults to the east and west of the geothermal field (Unruh and Hauksson, 2006; Monastero et al., 2005).

For the Coso Wash and Geologic Best Case stress scenarios (Figure 14) a variety of fault orientations are stressed to near failure, even for friction coefficients as high as measured on fresh fracture surfaces in cores acquired from the CGF (Figure 7). These include both active normal faults along the margin of the CGF in Coso Wash (which are associated with current fumerole activity; see Davatzes and Hickman 2006) and normal and strike slip faults further to the west within the main CGF. This is consistent with the observation that earthquakes occur throughout the field in a variety of orientations (e.g., Feng and Lees, 1998; Unruh et al., 2002; Monastero et al., 2005). Even more faults -- at a greater diversity of orientations -- should be active in the present day stress field if the coefficient of friction on these faults was quite low, possibility related to the formation of phyllosilicates in fault zones which are expected to have coefficients of friction from 0.3 to ~0.45 (Lockner and Beeler, 2001; Davatzes and Hickman, 2005) and which would also suggest low permeability in the clay-rich fault cores. Low strength portions of the major normal faults resulting from the presence of clays are also particularly interesting because pressure differences and differences in fluid chemistry are recognized across the Coso Wash fault. Also of interest is the mechanical interaction of faults which can produce local perturbations in stress orientations and magnitudes that can facilitate dilation and focus and enhance fluid flow (e.g., Davatzes et al., 2005; Eichhubl and Davatzes, 2003).
Index Map

End Member
Pure Normal Faulting
- $S_{\text{min}}' / S_v' = 0.4417$
- $S_{\text{max}}' / S_v' = 0.4417$
- $S_{\text{max}}' / S_v' = 1.000$
- $\text{azimuth } S_{\text{min}} = 108^\circ$

East Flank
Transitional Normal - Strike-slip Faulting
- $S_{\text{min}}' / S_v' = 0.4461$
- $S_{\text{max}}' / S_v' = 0.9848$
- $S_{\text{max}}' / S_v' = 1.0000$
- $\text{azimuth } S_{\text{min}} = 99^\circ$

Coso Wash
Strike-Slip Faulting Regime
- $S_{\text{min}}' / S_v' = 2.1414$
- $S_{\text{max}}' / S_v' = 1.0000$
- $\text{azimuth } S_{\text{min}} = 106.1^\circ$

Geologic Best Case
Strike-Slip Faulting Regime
- $S_{\text{min}}' / S_v' = 0.4335$
- $S_{\text{max}}' / S_v' = 2.0046$
- $S_{\text{max}}' / S_v' = 1.0000$
- $\text{azimuth } S_{\text{min}} = 108^\circ$

**Notes:**
- Stress magnitudes are normalized to $S_{\text{min}}$, and adjusted to effective stresses.
- Strike-slip faults assumed to dip 89°.
- Normal faults assumed to dip 60°.
Fault Rocks
Fault rock mineralogy and texture provide a further control on the formation and maintenance of fluid flow in the geothermal field (Davatzes and Hickman, 2005b) that is not addressed by the above analysis of fault geometry and stress. Core from East Flank well 64-16 reveals two end-member classes of fault rocks at depth: (1) cataclastic fault rocks with mineralogy similar to the host rock but with increased porosity; (2) well-developed clay-rich fault rocks characterized by extremely small, disconnected pores (Davatzes and Hickman, 2005b). These distinct fault zone mineralogies and textures imply variation in the frictional strength, permeability, and slip-induced dilatancy of fault zones (Lockner and Beeler, 2002) within the Coso geothermal field. Whereas we know these different fault types are developing in the geothermal field (Davatzes and Hickman, 2005b), we currently do not have enough data to adequately describe their three-dimensional distribution and thus incorporate their impact into an EGS stimulation strategy.

Surface Hydrothermal Activity
Surface expressions of hydrothermal fluid flow in the CGF include steaming ground, fumaroles, and hydrothermal alteration/deposition (Hulen, 1978; Roquemore, 1981; Adams et al., 2000). Earliest surface evidence of geothermal activity in the field is represented by the 307ka travertine deposits (Adams et al., 2000), which is offset by segments of the Coso Wash fault. Subsequently, sinter indicating higher temperature hydrothermal activity was deposited at approximately 238ka (Duffield et al., 1981; Echols et al., 1986; Hulen, 1987). The current hydrothermal activity has developed within the last 10ka and fumaroles. Reservoir boiling leading to acid alteration distributed along fault traces appears to be modern.

These features are preferentially distributed along major NNE-SSW trending normal faults with clear geomorphic expressions such as retaining ponds and fault scarps in basin fill. Intersections between NNE-SSW trending faults and nearly WNW-ESE trending faults (Figure 1a) also appear to localize intense hydrothermal activity. These circumstances support the hypothesis that fluid flow is largely focused along the most active faults and fractures in the CGF. However, simple analysis of the fault geometry and stress state does not currently account for variations in the distribution of hydrothermal activity (Figure 14). Other variables such as the physical properties of fault rocks (Davatzes and Hickman, 2005b), reservoir engineering practices, and the complex 3D fault geometry and mechanical interactions between nearby faults under the current stress field will be addressed in a future study.

2.4.4.1.6 Conclusions
Stress orientations from both borehole data and earthquake focal mechanism inversions suggest a consistent remote horizontal stress orientation where \( S_{\text{hmin}} \) is \( \sim 108^\circ \pm 24^\circ \) throughout the productive geothermal field. A faulting regime that favors strike slip faulting regime that favors oblique slip on existing normal faults in the East Flank of the field is suggested by hydraulic fracturing stress tests that measure \( S_{\text{hmin}} \), constraints on \( S_{\text{Hmax}} \) from borehole breakouts and rock strength, and Holocene sediments offset by modern basin-bounding normal faults. These measurements are also consistent with inversions of seismicity in the upper 0.5 to 2.5 km of the field and surface deformations measured from InSAR, which indicate that the East Flank and southern portion of the Main Field are actively extending (Fialko and Simons, 2000; Wicks et al., 2001). Since low mean stress faulting regimes facilitate dilation during fault slip, these results suggest that well 46A-19RD is well situated for EGS stimulation through injection-induced shear failure to enhance permeability in a hot but low permeability portion of the Main Field.

2.4.4.1.7 Sensitivity to Bottom-Hole Shape

Dr. David Lockner and Dr. Carolyn Morrow conducted the rock mechanics experiments at the USGS in consultation with Nick Davatzes and Steve Hickman. Much of well log data analyzed was made available through the Navy Geothermal Program Office. Funding for N. Davatzes’ salary was provided by a U.S. Geological Survey Mendenhall Fellowship. Funding for new data acquired as part of the Enhanced Geothermal Systems project was funded by the Department of Energy Geothermal Program.

2.4.4.1.8 Acknowledgments

An initial investigation to identify potential boundary conditions controlling the distribution of petal-centerline fractures in well 58A-10 has produced no simple relationship to proxies for rock strength, loading conditions, or borehole geometry (Figure 10). Petal-centerline distribution appears to cluster in discrete zones uncorrelated to any single parameter. It should be noted that a longer survey spanning a broader range of boundary conditions would be more likely to produce clear relationships among these parameters which could then be incorporated into modeling efforts.

2.4.4.1.9 References


Reference Data Tables

<table>
<thead>
<tr>
<th>Rock Type (Approximate)</th>
<th>Well</th>
<th>Depth Interval [m MD (ft MD)]</th>
<th>Sample #</th>
<th>Hand Sample Description</th>
<th># of CP samples</th>
<th># of $V_P$ or K samples</th>
</tr>
</thead>
<tbody>
<tr>
<td>Granodiorite</td>
<td>34-9RD2</td>
<td>2562.45 –</td>
<td>B3 R3 - 1b</td>
<td>Light colored, weak</td>
<td>8</td>
<td>2</td>
</tr>
</tbody>
</table>

2.4.5 Appendix A: Physical Properties of Core obtained from well 34-9RD2


Altered and healed specimen

34-9RD2

2430.45 – 2430.65 (7,973’11” – 7974’7”)

B1 R1 – 1f and 1g

Dark colored, many healed fractures

Dark colored, coarse grained, slight to medium foliation

Hornblende Biotite Diorite

58A-10

Table 2: Estimated confining pressure in depth interval targeted for stimulation

<table>
<thead>
<tr>
<th>Depth [m MD (ft MD)]</th>
<th>Avg. Rock Density [g/cc]</th>
<th>S\textsubscript{v} [MPa (psi)]</th>
<th>P\textsubscript{p} [MPa (psi)]</th>
<th>Effective confining pressure % of Confining Pressure at target stimulation depth (10,000 ft MD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3048 (10,000*)</td>
<td>2.65</td>
<td>78.6 (11,400)</td>
<td>26.48 (3,840)</td>
<td>52.13 (7,560)</td>
</tr>
<tr>
<td>3962.4 (13,000*)</td>
<td>2.65</td>
<td>101.36 (14,700)</td>
<td>34.20 (4,960)</td>
<td>67.15 (9,740)</td>
</tr>
</tbody>
</table>

* Corresponds to stimulation interval

Effective confining pressures for Compressive Strength, Residual Strength (i.e., coefficient of static friction), and V\textsubscript{p} measurements relative to a 10,000 ft stimulation target depth:

Table 3: Relationship of experiment confining pressures to estimated pressure at stimulation depth

<table>
<thead>
<tr>
<th>Effective Confining pressure [Mpa]</th>
<th>% of Confining Pressure at target stimulation depth (10,000 ft MD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. 0 [Mpa]</td>
<td>0.00 (unconfined)</td>
</tr>
<tr>
<td>2. 13.03 [Mpa]</td>
<td>0.25</td>
</tr>
<tr>
<td>3. 26.06 [Mpa]</td>
<td>0.50</td>
</tr>
<tr>
<td>4. 52.13 [Mpa]</td>
<td>1.00</td>
</tr>
<tr>
<td>5. 78.19 [Mpa]</td>
<td>1.50</td>
</tr>
</tbody>
</table>

Data in Tables 4 through 7 is principally derived from Morrow and Lockner (2006) and TerraTek (2004).
### Table 4: Physical Properties

<table>
<thead>
<tr>
<th>Sample</th>
<th>Sample Name</th>
<th>Porosity</th>
<th>Grain Density [g/cm$^3$]</th>
<th>Depth [m MD (ft MD)]</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>USGS data</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Well 34-9RD2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Granodiorite</td>
<td>B3 R3 1c1</td>
<td>1</td>
<td>2.642</td>
<td>2562.45 (8407)</td>
</tr>
<tr>
<td></td>
<td>B3 R3 1c2</td>
<td>1</td>
<td>2.654</td>
<td>2562.45 (8407)</td>
</tr>
<tr>
<td>Diorite</td>
<td>B1 R1 1f1</td>
<td>0.6</td>
<td>2.886</td>
<td>2430.48 (7974)</td>
</tr>
<tr>
<td></td>
<td>B1 R1 1f2</td>
<td>1</td>
<td>2.815</td>
<td>2430.48 (7974)</td>
</tr>
<tr>
<td><strong>TerraTek Data</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Well 64-16</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hornblende-biotite-quartz diorite</td>
<td>EGI-7</td>
<td>0.8</td>
<td>2.877</td>
<td>860.94 (2824.6)</td>
</tr>
<tr>
<td></td>
<td>EGI-6</td>
<td>0.9</td>
<td>2.874</td>
<td>860.94 (2824.6)</td>
</tr>
<tr>
<td></td>
<td>EGI-8</td>
<td>0.9</td>
<td>2.884</td>
<td>860.94 (2824.6)</td>
</tr>
<tr>
<td></td>
<td>EGI-9</td>
<td>0.9</td>
<td>2.893</td>
<td>860.98 (2824.75)</td>
</tr>
<tr>
<td></td>
<td>EGI-10</td>
<td>0.8</td>
<td>2.874</td>
<td>860.98 (2824.75)</td>
</tr>
<tr>
<td></td>
<td>EGI-11</td>
<td>0.9</td>
<td>2.894</td>
<td>860.98 (2824.75)</td>
</tr>
<tr>
<td>Biotite granodiorite</td>
<td>EGI-18</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>EGI-2</td>
<td>0.8</td>
<td>2.647</td>
<td>875.34 (2871.85)</td>
</tr>
<tr>
<td></td>
<td>EGI-4</td>
<td>0.8</td>
<td>2.65</td>
<td>875.28 (2871.65)</td>
</tr>
<tr>
<td></td>
<td>EGI-12</td>
<td>0.8</td>
<td>2.652</td>
<td>875.19 (2871.35)</td>
</tr>
<tr>
<td></td>
<td>EGI-13</td>
<td>0.8</td>
<td>2.652</td>
<td>875.19 (2871.35)</td>
</tr>
<tr>
<td></td>
<td>EGI-14</td>
<td>0.7</td>
<td>2.651</td>
<td>875.19 (2871.35)</td>
</tr>
<tr>
<td>Sample Name</td>
<td>Confining Pressure, $P_c$ [MPa]</td>
<td>Peak Sigma1 [MPa]</td>
<td>Peak Differential Stress [MPa]</td>
<td>Depth [m (ft)]</td>
</tr>
<tr>
<td>-------------</td>
<td>-------------------------------</td>
<td>------------------</td>
<td>-------------------------------</td>
<td>----------------</td>
</tr>
<tr>
<td>USGS data</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Well 34-9RD2</td>
<td>0.00</td>
<td>240.20</td>
<td>240.20</td>
<td>2562.45 (8407.00)</td>
</tr>
<tr>
<td>Granodiorite</td>
<td>13.00</td>
<td>387.10</td>
<td>374.10</td>
<td>2562.45 (8407.00)</td>
</tr>
<tr>
<td></td>
<td>26.00</td>
<td>596.60</td>
<td>570.60</td>
<td>2562.45 (8407.00)</td>
</tr>
<tr>
<td></td>
<td>52.10</td>
<td>770.00</td>
<td>717.90</td>
<td>2562.45 (8407.00)</td>
</tr>
<tr>
<td></td>
<td>78.20</td>
<td>945.20</td>
<td>867.00</td>
<td>2562.45 (8407.00)</td>
</tr>
<tr>
<td>Diorite</td>
<td>0.00</td>
<td>186.00</td>
<td>186.00</td>
<td>2430.48 (7974.00)</td>
</tr>
<tr>
<td></td>
<td>13.00</td>
<td>301.00</td>
<td>288.00</td>
<td>2430.48 (7974.00)</td>
</tr>
<tr>
<td></td>
<td>26.00</td>
<td>323.30</td>
<td>297.30</td>
<td>2430.48 (7974.00)</td>
</tr>
<tr>
<td></td>
<td>52.10</td>
<td>633.90</td>
<td>581.80</td>
<td>2430.48 (7974.00)</td>
</tr>
<tr>
<td></td>
<td>78.20</td>
<td>581.80</td>
<td>503.60</td>
<td>2430.48 (7974.00)</td>
</tr>
<tr>
<td>TerraTek Data</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Well 64-16</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hornblende-biotite-quartz diorite</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EGI-7</td>
<td>0.00</td>
<td>193.21</td>
<td>193.21</td>
<td>860.94 (2824.60)</td>
</tr>
<tr>
<td>EGI-6</td>
<td>12.41</td>
<td>255.83</td>
<td>243.41</td>
<td>860.94 (2824.60)</td>
</tr>
<tr>
<td>EGI-8</td>
<td>24.83</td>
<td>309.79</td>
<td>284.97</td>
<td>860.94 (2824.60)</td>
</tr>
<tr>
<td>EGI-9</td>
<td>49.66</td>
<td>429.59</td>
<td>379.93</td>
<td>860.98 (2824.75)</td>
</tr>
<tr>
<td>EGI-10</td>
<td>49.66</td>
<td>394.93</td>
<td>345.28</td>
<td>860.98 (2824.75)</td>
</tr>
<tr>
<td>EGI-11</td>
<td>74.48</td>
<td>508.90</td>
<td>434.41</td>
<td>860.98 (2824.75)</td>
</tr>
<tr>
<td>Biotite granodiorite</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EGI-18</td>
<td>0.00</td>
<td>345.24</td>
<td>345.24</td>
<td>875.19 (2871.35)</td>
</tr>
<tr>
<td>EGI-2</td>
<td>12.41</td>
<td>506.69</td>
<td>494.28</td>
<td>875.19 (2871.35)</td>
</tr>
<tr>
<td>EGI-4</td>
<td>24.83</td>
<td>627.59</td>
<td>602.76</td>
<td>875.19 (2871.35)</td>
</tr>
<tr>
<td>EGI-12</td>
<td>49.66</td>
<td>827.31</td>
<td>777.66</td>
<td>875.19 (2871.35)</td>
</tr>
<tr>
<td>EGI-13</td>
<td>49.66</td>
<td>787.48</td>
<td>737.83</td>
<td>875.19 (2871.35)</td>
</tr>
<tr>
<td>EGI-14</td>
<td>74.48</td>
<td>967.17</td>
<td>892.69</td>
<td>875.19 (2871.35)</td>
</tr>
</tbody>
</table>
### Table 6: Friction

<table>
<thead>
<tr>
<th>Sample Name</th>
<th>Pc [MPa]</th>
<th>Differential Stress [MPa]</th>
<th>Shear Stress [MPa]</th>
<th>Normal Stress [MPa]</th>
<th>$\mu_s$ (residual)</th>
<th>$\mu_i$ (internal, calculated from failure angle)</th>
<th>$\mu_i$ (internal, calc. from failure envelope)</th>
</tr>
</thead>
<tbody>
<tr>
<td>USGS data Well 34-9RD2</td>
<td>0</td>
<td>1.38</td>
<td>1.32</td>
<td>Granodiorite</td>
<td>13</td>
<td>88.2</td>
<td>31.7</td>
</tr>
<tr>
<td></td>
<td>26</td>
<td>131.6</td>
<td>34.9</td>
<td>36</td>
<td>0.97</td>
<td>1.60</td>
<td>1.32</td>
</tr>
<tr>
<td></td>
<td>52.1</td>
<td>269.5</td>
<td>93.6</td>
<td>89.9</td>
<td>1.04</td>
<td>1.04</td>
<td>1.32</td>
</tr>
<tr>
<td></td>
<td>78.2</td>
<td>285.78</td>
<td>88</td>
<td>108.5</td>
<td>0.81</td>
<td>1.28</td>
<td>1.32</td>
</tr>
<tr>
<td>Diorite</td>
<td>0</td>
<td>1.38</td>
<td>1.29</td>
<td></td>
<td>13</td>
<td>54.8</td>
<td>17.6</td>
</tr>
<tr>
<td></td>
<td>26</td>
<td>87.4</td>
<td>28.1</td>
<td>36.2</td>
<td>0.76</td>
<td>1.19</td>
<td>1.29</td>
</tr>
<tr>
<td></td>
<td>52.1</td>
<td>182.1</td>
<td>53.5</td>
<td>69.5</td>
<td>0.77</td>
<td>1.38</td>
<td>1.29</td>
</tr>
<tr>
<td></td>
<td>78.2</td>
<td>252.7</td>
<td>96.8</td>
<td>132.3</td>
<td>0.73</td>
<td>0.84</td>
<td>1.29</td>
</tr>
<tr>
<td>TerraTek Data Well 64-16 Hornblende-biotite-quartz diorite</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EGI-7</td>
<td>0</td>
<td>Angle of fracture at failure not recorded,</td>
<td>cannot calculate coefficient of friction</td>
<td></td>
<td>0.79</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EGI-6</td>
<td>12.41</td>
<td></td>
<td></td>
<td></td>
<td>0.79</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EGI-8</td>
<td>24.83</td>
<td></td>
<td></td>
<td></td>
<td>0.79</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EGI-9</td>
<td>49.667</td>
<td></td>
<td></td>
<td></td>
<td>0.79</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EGI-10</td>
<td>49.66</td>
<td></td>
<td></td>
<td></td>
<td>0.79</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EGI-11</td>
<td>74.48</td>
<td></td>
<td></td>
<td></td>
<td>0.79</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Biotite granodiorite</td>
<td>EGI-18</td>
<td>0</td>
<td>1.26</td>
<td>EGI-2</td>
<td>12.41</td>
<td>1.26</td>
<td></td>
</tr>
<tr>
<td></td>
<td>EGI-4</td>
<td>24.83</td>
<td>1.26</td>
<td>EGI-12</td>
<td>49.66</td>
<td>1.26</td>
<td></td>
</tr>
<tr>
<td></td>
<td>EGI-13</td>
<td>49.66</td>
<td>1.26</td>
<td>EGI-14</td>
<td>74.48</td>
<td>1.26</td>
<td></td>
</tr>
</tbody>
</table>

### Table 7: Measured Velocity Data

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>3.434</td>
<td>3.53</td>
<td>5.805</td>
<td>5.779</td>
</tr>
<tr>
<td>10</td>
<td>4.581</td>
<td>5.177</td>
<td>6.377</td>
<td>5.802</td>
</tr>
<tr>
<td>13</td>
<td>5.297</td>
<td>6.408</td>
<td></td>
<td></td>
</tr>
<tr>
<td>20</td>
<td>5.179</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>26</td>
<td>5.441</td>
<td>5.364</td>
<td>6.437</td>
<td>6.154</td>
</tr>
<tr>
<td>52.1</td>
<td>5.641</td>
<td>5.396</td>
<td>6.449</td>
<td>6.154</td>
</tr>
<tr>
<td>78.2</td>
<td>5.675</td>
<td>5.416</td>
<td>6.461</td>
<td>6.195</td>
</tr>
<tr>
<td>Avg.</td>
<td>5.532</td>
<td></td>
<td></td>
<td>6.322</td>
</tr>
</tbody>
</table>
### Table 8: Elastic Moduli

<table>
<thead>
<tr>
<th>Sample Name</th>
<th>Pc  [MPa]</th>
<th>Poisson's Ratio</th>
<th>Young's Modulus [GPa]</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>USGS data</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Well 34-9RD2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Granodiorite</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B3 R3 1c1</td>
<td>52.1</td>
<td>0.277</td>
<td>74.1</td>
</tr>
<tr>
<td>B3 R3 1c2</td>
<td>78.2</td>
<td>0.27</td>
<td>75.4</td>
</tr>
<tr>
<td>Diorite</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B1 R1 1f1</td>
<td>52.1</td>
<td>0.311</td>
<td>105.1</td>
</tr>
<tr>
<td>B1 R1 1f2</td>
<td>78.2</td>
<td>0.313</td>
<td>100.7</td>
</tr>
<tr>
<td><strong>TerraTek Data</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Well 64-16</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hornblende-biotite-quartz diorite</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EGI-7</td>
<td>0</td>
<td>0.15</td>
<td>63.70</td>
</tr>
<tr>
<td>EGI-6</td>
<td>12.41</td>
<td>0.1975</td>
<td>60.02</td>
</tr>
<tr>
<td>EGI-8</td>
<td>24.83</td>
<td>0.24</td>
<td>62.64</td>
</tr>
<tr>
<td>EGI-9</td>
<td>49.66</td>
<td>0.2</td>
<td>72.63</td>
</tr>
<tr>
<td>EGI-10</td>
<td>49.66</td>
<td>0.2275</td>
<td>69.89</td>
</tr>
<tr>
<td>EGI-11</td>
<td>74.48</td>
<td>0.2975</td>
<td>72.76</td>
</tr>
<tr>
<td>Biotite granodiorite</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EGI-18</td>
<td>0</td>
<td></td>
<td>70.90</td>
</tr>
<tr>
<td>EGI-2</td>
<td>12.41</td>
<td>0.245</td>
<td>71.54</td>
</tr>
<tr>
<td>EGI-4</td>
<td>24.83</td>
<td>0.21</td>
<td>74.38</td>
</tr>
<tr>
<td>EGI-12</td>
<td>49.66</td>
<td>0.2225</td>
<td>78.22</td>
</tr>
<tr>
<td>EGI-13</td>
<td>49.66</td>
<td>0.1725</td>
<td>78.72</td>
</tr>
<tr>
<td>EGI-14</td>
<td>74.48</td>
<td>0.22</td>
<td>81.19</td>
</tr>
</tbody>
</table>
Appendix B: Mechanics of Formation of Petal Centerline Fractures

2.1 Synopsis
Estimating the orientation and magnitude of remote principal stresses acting in the Coso Geothermal Field is a key element of the stimulation strategy for the EGS project. In this study we present and discuss a previously unrecognized petal-centerline fractures which form ahead of the drill bit during drilling and are indicators of stress orientation. Use of these structures has the potential to greatly increase the understanding of stress heterogeneity in the Coso geothermal field.

2.2 Constraint on Stress at Depth from Borehole Image Logs
Concentration of stress along the free surface of the borehole is often enough to exceed the rock strength and produce borehole wall failure visible in image logs (Figure 1). The orientation and nature of the stresses that produce this failure is well-described by the Kirsh equations along the borehole wall (Jaeger and Cook, 1979) and can be clearly related to the remote stress state and local borehole conditions (e.g., see Zoback et al., 2003 for a summary). Typically, increased compression is related to the formation of breakouts where this compression exceeds the uniaxial strength of the rock constituting the borehole wall. Similarly, tensile cracks may form due to locally generated tensile stresses enhanced by high mud pressure relative to formation pressure and thermal cooling stresses.

![Borehole wall failure: Breakouts and Tensile Cracks](image.png)

Figure 1: Failure of borehole wall breakouts and tensile cracks in Coso well 58A-10 revealed by acoustic borehole televiewer (BHTV) logs (ALT ABI85, a new televiewer developed under the auspices of the Navy Geothermal Program Office, the DOE Geothermal Program, Sandia National Lab, and the USGS for high temperature geothermal borehole studies) and electrical image logs collected using the Schlumberger Hot Hole Formation Micro-Scanner (FMS).
A third class of structures called petal-centerline fractures has previously been recognized in core. These structures form due to the complex stress concentration below the floor of a borehole as it advances during drilling rather than in the borehole wall as inferred for breakouts and tensile cracks. While they have been recognized in core from many locations (Pendexter and Rohn, 1954; GangaoRao et al., 1979; Kulander et al., 1979; Lorenz and Finley, 1988) they have typically not been identified in image logs of rotary drilled boreholes. In the Coso geothermal field, these structures appear to constitute a significant percentage of the total drilling induced structures in the borehole although they were not recognized prior to the use of the new ALT ABI85 borehole televiewer (Davatzes and Hickman, 2005); for instance in well 58A-10, 222.1 m out of the 318.1 m total length of induced structures, or ~69.8% of the available data, are identified as petal-centerline fractures in the borehole televiewer logs.

In this contribution we present criteria for successfully identifying petal-centerline fractures, provide evidence that they consistently strike in the direction of $S_{\text{Hmax}}$, demonstrate the potential errors due to misidentification, and discuss a conceptual model for their growth.

### 2.3 What are Petal Centerline Fractures?: Characteristics of Petal-centerline fractures in Core

Petal-centerline fractures are interpreted to form ahead of the drill bit due to the complex concentration of stress at the floor of the borehole (Figure 10a) (Kulander et al., 1990; Lorenz et al., 1990; Li and Schmitt, 1997, 1998). These induced fractures are thought to be favored in normal to strike slip faulting environments because of low mean stresses that facilitate tensile failure and are promoted by high mud weights, the rough geometry of the borehole floor (Li and Schmitt, 1998), and low tensile strength. They have long been recognized in core, and both empirical studies of oriented core (Lorenz and Finley, 1988; Kulander et al., 1979, 1990; Lorenz et al., 1990) and theoretical studies (Lorenz et al., 1990; Li and Schmitt, 1997, 1998) demonstrate that they strike parallel to $S_{\text{Hmax}}$.

Two elements of these induced fractures are typically distinguished, including the petal and the centerline. Petal fractures curve from the margin of the core towards parallelism with the core axis as they penetrate the core. The curving geometry indicates continuous fracture propagating through spatially changing stress boundary conditions (Figure 2). The curvature of the petals occurs in less than one core radius and thus indicates large stress orientation changes over distances much less than the borehole diameter. Centerline fractures result from continued propagation of a petal once it is parallel to the core axis, although they seldom coincide with the core axis. In general, centerline fractures do not appear to exist in the absence of petals. Centerline fractures often extend substantially longer along the core axis than the height of the associated petal.

The surfaces of these fractures are typically marked by plumose structures (Figure 2). The presence of plumose structures such as arrest lines on the surface of the petal-centerline fracture indicates the fracture formed by opening mode failure. Opening mode failure results from tensile stresses that exceed the tensile strength of the rock. The resulting failure surface, or fracture, consistently propagates normal to the least compressive principal stress. The arrest lines record the history of fracture propagation, specifically the position of the fracture’s termination, called the tip-line, of the opening mode fracture at each growth increment (Pollard and Aydin, 1988).
Conversely, they also indicate the location of fracture initiation. As in Figure 1, the arrest lines typically do not enclose an initiation point within the core, suggesting initiation begins in the rock outside of the core either at the kerf or potentially outside the borehole footprint. The exact location is difficult to discern as the spacing between arrest lines need not be constant.

Figure 2: Arrest lines along the surface of an opening mode fracture record the propagation history of the fracture (modified from Lorenz and Finley, 1988). The arrest lines and geometry of the fracture demonstrate three key characteristics of petal-centerline fracture. (1) A downward curving petal fracture (looking like a chevron in 2-D) that smoothly curves into a steeply dipping fracture. (2) The arrest lines do not enclose an initiation point within the core. (3) Since the arrest lines mark the former boundaries of the propagating fracture, the low curvature of the arrest lines and their abrupt termination at the edge of the core indicate that the petal-centerline fracture likely extends a substantial distance outside the core, potentially in excess of one to two borehole diameters into the rock surrounding the borehole.

Petal fractures often occur as nested sets. In these cases a smoothly connected centerline fracture appears to be absent. Instead, small fractures extend from the tip of one petal and abut against the back of the next adjacent petal on the concave side of the petal at a 90° angle (Figure 3). Note that connecting fractures define a kinked angle. This kinked angle suggests two stages of growth of the petal and connecting fracture pair separated by a local stress rotation such as might result from development of the next petal-centerline below. Plumose structures indicated that the connecting fractures propagate from the tip of the petal to the next petal. The cause for the arrest of petals and lack of a centerline in core is not always clear; however, in many cases the petals abut against other structures such as bedding (Kulander et al., 1990) or natural fractures. The frequency, or spacing, of petals appears to be rock-type dependent indicating that it correlates with the mechanical properties of the rock such as stiffness and compressibility (Lorenz and Finley, 1988).
2.4 Recognizing Petal-Centerline Fractures in Image Logs

In image logs plumose structures are not available to verify the failure mode of fractures observed to intersect the borehole wall. However, we use the geometry of these fractures and their orientation relative to other structures such as borehole breakouts and tensile cracks as criteria for identifying these structures.

In image logs petal fractures appear as smoothly curving chevrons (pointing up or down). The tips of the chevrons merge with pairs of centerline fractures oriented parallel to the borehole axis (Figure 4) consistent with examples in core (Kulander et al., 1990). Multiple nested chevrons are commonly distributed along a single or nested pairs of centerline fractures. Occasionally, centerline fractures terminate in petals at both ends, producing oval-shaped fracture patches (Figure 4). In these image logs, multiple petals often occur as nested sets (similar to core) or associated with a single centerline fracture. In detail, these petals typically intersect the other petals or the centerline through high angle, near 90°, connecting fractures intersecting either petal or centerline by sharp, kinked angles (Figure 4). This geometry is consistent with open petals and centerlines that support little shear stress, as would be expected from open fractures resulting from tensile failure and consistent with observations in core.
Figure 4: Nested petal-centerline fractures in BHTV and FMS data. Related centerline fractures are indicated as numbered pairs which are often connected by petals that are evident in the BHTV image but not in the FMS image where they are also indistinguishable from borehole wall tensile fractures. \( S_{hmin} \) is only determined from the average of matched pairs. Petal fracture chevrons point both up and down-hole and might form elliptical traces in the borehole wall. Care must be taken so that the petal-centerline fractures are not mistaken for steeply dipping, slightly non-planar natural fractures. These induced fractures also interact and sometimes abut against natural fractures. Sketch of petal (light green) and centerline (dark green) fractures visible in borehole televiewer image log at ~7000 ft MD from well 58A-10. Cartoon at right illustrate one possible centerline configuration used to calculate \( S_{hmin} \) by determining the normal to the strike of the induced structure from the average of the azimuth of the petal-centerline fracture with the borehole wall.

Whereas the symmetrical stress concentration around the borehole free surface causes classic borehole wall tensile fractures to form 180° apart (Figure 1), petal-centerline fractures propagate through intact rock ahead of the drill bit as opening-mode fractures that open in the local direction of the least compressive principal stress (Figure 4). The resulting fracture plane strikes parallel to \( S_{Hmax} \), but does not necessarily lie along the borehole axis. Thus, once the bit has drilled through the induced fracture, the petal-centerline fracture will have variable azimuthal spacing along the borehole wall. The orientation of \( S_{hmin} \) can then only be reliably estimated by calculating the average azimuth of pairs of genetically related centerline fractures or paired measurements on both limbs of petal fractures (cartoon in Figure 4).

In several cases (see Figure 4) the trace of petal fractures along the borehole wall appears to be incomplete; that is the two limbs of the petals do not completely connect. It is important to note...
that the only way for this to occur is if this tip actually resided within the material drilled away by the borehole, indicating initiation of the petal from the borehole floor, which then quickly grew out along strike to a width greater than the borehole diameter.

In FMS images, pairs of centerline fractures are unlikely to be completely imaged because they need not form 180° apart and FMS pads are spaced at 90° increments (although greater coverage in other electrical imaging tools such as the FMI will reduce this limitation). As a result, centerline fractures spaced less than 180° could be misinterpreted as classic borehole wall tensile fractures (FMS image in Figure 1). Similarly, petal fractures might mistakenly appear to be parts of natural fractures in an FMS log. The potential for such misinterpretation is exacerbated where these fractures are nested (Figures 4). Practically, use of an FMS log alone is thus prone to increased scatter in measured orientations of $S_{\text{hmin}}$ or a diminished density of induced fracture picks as many examples would have an ambiguous origin. Using a BHTV log and applying the same averaging technique to all tensile fractures, including those produced by borehole wall failure, helps to avoid this pitfall. Figure 5 illustrates an example where such confusion is likely in the FMS. This example also reveals an abutting relationship visible in BHTV log that confirms that classic borehole wall tensile fractures form after petal fractures.

![Figure 5: BHTV and FMS image logs of classic borehole tensile cracks (blue) abutting against a petal-centerline fracture (light and dark green respectively). The abutting relationship circled in black in the sketch confirms that the petal-centerline fractures formed before the tensile failure of the borehole wall. This relationship is not visible in the FMS image, where one could easily mistake a petal-centerline fracture for a true borehole wall tensile crack (arrows).](image)

As a final note, in the interpretation of image logs care should be taken to avoid confusing petal-centerline fractures from slightly non-planar fractures inclined at low angles to the borehole (fractures nearly parallel to the borehole axis). In this case it is useful to note that petal-centerline fractures typically provide only a single chevron as opposed to the complete sinusoid of a well-imaged natural fracture. In addition, the limbs of this chevron will curve into parallelism with the borehole axis in typically much less than a 180° span. In cases of doubt, the interpreter can always neglect to make a pick.

2.5 Conceptual model of Petal-Centerline Crack Development
We are currently refining our conceptual model of petal-centerline formation in a rotary-drilled borehole. Rotary drilled boreholes appear to provide relatively flat-bottomed borehole floors with a small radius curvature where the borehole floor and borehole wall meet. This geometry results in local tensile stresses near the floor of the borehole and stress rotations (Figure 6a). The stress concentration, that is the degree to which the remote stress state is amplified or altered, is strongly influenced by the degree of curvature of this bottom-hole geometry. A smaller radius of curvature maximizes the stress perturbation. In the plane that contains \( S_{\text{hmin}} \) and the borehole axis, the principal stresses rotate strongly about the \( S_{\text{Hmax}} \) axis, thus the strike of the petal-centerline fracture preserves the \( S_{\text{Hmax}} \) azimuth (unpublished modeling results from this on-going study; see also Li and Schmidt, 1998). The largest rotations occur near the margins of the borehole floor consistent with the observed geometry of petal fractures rotating into centerline fractures.

Although the most tensile stresses develop immediately below the borehole floor, reduced compression extends several borehole radii laterally and below the borehole. Thus petal fractures are most likely to nucleate at the borehole floor (Figure 6b, \( t_1 \)) (a potential difference between rotary drilled bore holes and coreholes), which would result in incomplete petal-traces as shown in Figures 4 and 5. As the petal grows it propagates in the plane normal to the least compressive principal stress, \( \sigma_3 \), growing toward and curving to become parallel with the borehole axis (Figure 6a and b, \( t_2 \)) to define a centerline fracture. At this point the petal might arrest, potentially due to either a pre-existing heterogeneity in the rock or due to the stress shadow of a newly formed or propagating petal fracture. Existing fractures crossed by the borehole are likely to interact with the borehole stress concentration as well and might provide arrest and interaction points if they are weak and slip as depicted in \( t_3 \). This circumstance could also impact the location of petal fracture nucleation as depicted in \( t_4 \).
Despite insights from core and new insights from image log analysis, several key issues remain unresolved and require further research. The first concern is what determines the point of initiation of the petal-centerline fractures. Core studies indicate that the petal initiates outside the core and potentially outside the borehole footprint. Taking a fracture mechanics perspective it is likely that petal centerline fractures initiates at flaws that provide local concentrations of stress in addition to the affects of the borehole.

Two classes of these flaws are readily apparent. First, the rough geometry of the borehole floor will produce large magnitude, but spatially small stress concentrations which might provide initiation points. This region is superposed on the most tensile region resulting from the stress perturbation related to the gross geometry of the borehole. In a coring operation this region could be represented by the kerf, whereas in a rotary drilled borehole this region includes the entire floor of the borehole. Incomplete upward pointing petal fractures (as in Figure 4) would be consistent with a point of initiation at the borehole floor. Alternatively, small cracks outside the borehole footprint might provide initiation points, consistent with the example in Figure 2 from Lorenz and Finley (1988). Although absolute tension is less likely outside the borehole footprint, axially symmetric lobes of less compressive $\sigma_3$ extend laterally one to two borehole radii below and to the side of the borehole and are likely to affect pre-existing structures (as depicted in
Figure 6, t_3 and t_4). In either case, the initiation point is most likely to occur in an area where stresses are rotated about the maximum horizontal principal stress axis. As a result, the initial fracture will be oblique to the borehole axis and propagate through a spatially varying stress field to produce a curving fracture geometry consisting of an upper petal (chevron in the image log) and a lower centerline fracture.

Coring studies of petal-centerline fractures identified in this contribution always show petal fractures that are concave down (downward open chevrons in the image logs). However, in the image logs of 58A-10, upward open chevrons are well-represented. Similarly, oval structures which might potentially present centerline fractures with upper and lower petals are also observed. Petals that are concave up are more difficult to explain in relation to the bottom-hole stress perturbation. One possible explanation is the interaction of the propagating fracture with existing natural fractures or other flaws that can locally rotate the stress state as alluded to in t_3 of Figure 6. While possible, this explanation is not particularly satisfying since it is not inherent to the stress concentration around the well-bore and relies on local conditions that are difficult to observe or predict. Further research including both borehole observations and modeling are needed to address this issue.

The last point of interest is how robustly petal-centerline fracture can be predicted from simple stress models. Or put another way, do these drilling-induced structures provide a useful means of constraining stress magnitude as is the case for breakouts? This is currently an un-resolved question.

2.6 Test of concept – Coso Well 58A-10
A large proportion, ~70%, of the tensile fractures evident in the BHTV image logs from well 58A-10 are interpreted as petal-centerline fractures. Our analysis of the BHTV data shows that petal-centerline fractures provide comparable stress orientations to breakouts and borehole wall tensile fractures (summarized in rose diagram of Figure 7a) and greatly increase the depth coverage of usable fractures in this case. In contrast, the FMS data (Figure 7b) shows considerably more scatter and fewer induced fracture picks because of the poor azimuthal coverage of the borehole wall and the inability to distinguish petal-centerline fractures from borehole wall tensile fractures. In addition, no breakouts were identified in the FMS image log, although many shallow breakouts were visible in the BHTV image log. The FMS mean S_{hmin} direction only departs by 3.9° from the BHTV analysis, but has a significantly larger standard deviation. Thus, this difference is probably a result of the sampling bias resulting from FMS pad spacing and the much smaller population of stress indicators that could be reliably sampled (including lack of breakouts seen in the FMS log). However, if the correction produced by averaging pairs of induced fractures is not used (Figure 7c), the standard deviation of the stress direction increases to 55.6°. This result represents an extreme case, as strict picking criteria in a careful analysis would have mitigated the result. However, by decimating the number of induced fractures picked, additional uncertainty would be introduced as well as a lack of resolution on the variability of the stress orientation.

The mean azimuth of S_{hmin} was determined by weighting individual measurements equal to the height of the structure measured. Breakouts, tensile fractures, and petal-centerline fractures are also given twice the weight of fractures in the borehole wall whose origin as a borehole wall
tensile fracture or a petal-centerline fracture cannot be distinguished. Circular statistics were used to calculate the mean $S_{\text{hmin}}$ direction and standard deviation. Analysis of these structures from the BHTV logs (Figure 7a) indicates that each type of induced structure provides a consistent azimuth of $S_{\text{hmin}}$ near well 58A-10 of $106.1^\circ \pm 15.6^\circ$.

The mean azimuth of $S_{\text{hmin}}$ is consistent with the local orientation of the Coso Wash normal fault just to the west of the well and another similarly striking, but west dipping normal fault to the east (Figure 1). The depth distribution of induced structures visible in the BHTV data also shows one prominent stress rotation at ~9750 ft near the locations of several large faults visible in the image logs (arrow in Figure 7). Several, other less prominent stress rotations are evident, such as at ~7350 ft MD. These rotations probably indicate active slip on faults nearby or intersecting the borehole. The rotations are only reliably identified where data trace the rotation along the well to the maximum rotation value. Thus, data density is a critical element in identifying stress rotations, which indicate active slip on faults and also is useful in characterizing the heterogeneity of stress in proximity to the well. These rotations would not be identifiable in the absence (or misinterpretation) of petal-centerline fracture, since they constitute the majority of induced structures in the well as illustrated in Figure 7.
Figure 7: From left to right in each row: Orientation of $S_{\text{hmin}}$ as a function of depth in well 58A-10, departure of the local stress direction from the global mean, histogram of induced structure frequency as a function of depth, and rose diagrams of induced structure orientations. The data quality for each log is indicated in the background as in Figure 7. Mean $S_{\text{hmin}}$ azimuth and one standard deviation is computed for each data set is computed using Fischer Statistics. Data are weighted by the height of the induced structures and breakouts, tensile fractures, and petal-centerline fractures are given twice the weight of undistinguished fractures. The local orientation of the $S_{\text{hmin}}$ azimuth us computed from Gaussian smoothing in a moving 75 ft window. (a) BHTV, (b) FMS, and (c) FMS without averaging of induced fracture pairs.

2.7 Sensitivity to bottom-hole shape
We are currently engaged in a collaborative study with Laurent Maerten and Frantz Maerten at IGEOSS using Poly3D, a linear elastic boundary element modeling code (Thomas, 1993) to evaluate the sensitivity of petal-centerline fracture formation to the remote stress boundary conditions, borehole shape, and other parameters. Changes in the magnitudes and orientations of local stresses are significantly affected by the bottom-hole geometry (Li and Schmidt, 1998) and will vary due to changes in the core stub geometry and the curvature of the transition from borehole wall to floor. Describing the variations in stress is an area of active research that will aid in interpreting petal-centerline fractures to constrain stress directions and potentially stress magnitudes. This investigation will include an examination of differences between the coring and rotary drilled case.

Some initial visualizations of stress around a flat-bottomed borehole are presented in Figure 8. Validation of initial models against the analytical Kirsch equations demonstrate that Poly3D gives similar results for locations where the borehole approximates the 2-D plane strain solution (Figure 9) assumed by Kirsch (1898) (see Jaeger and Cook, 1979).
Figure 8: Results from preliminary Poly3D models of the stress concentration around a flat-bottomed borehole. Tick marks indicate the orientation of opening-mode failure planes. Contours represent increased compression (blues) to reduced compression and tension (yellows to reds). Boundary conditions are taken from the East Flank final report for Coso Wash based on the combined analyses of EGS well 34-9RD2 in the East Flank and Navy well 58A-10 in Coso Wash. Stress perturbation in the (a) $S_{H\text{max}}$ plane, (b, c) the $S_{H\text{min}}$ plane. Series views of stress contours in multiple observation planes from (d) just above, to (e) at, to (f) just below the borehole floor.

Figure 9: Validation comparison between the Kirsch equations and results from Poly3D for the stress around the borehole wall far away from the upper or lower termination of the borehole. Test courtesy of Laurent Maerten of IGEOSS.

2.8 In Situ Boundary Conditions Controlling Petal Centerline Fracture Distribution

An initial investigation to identify potential boundary conditions controlling the distribution of petal-centerline fractures in well 58A-10 has produced no simple relationship to proxies for rock strength, loading conditions, or borehole geometry (Figure 10). Petal-centerline distribution appears to cluster in discrete zones uncorrelated to any single parameter. It should be noted that a longer survey spanning a broader range of boundary conditions would be more likely to produce clear relationships among these parameters which could then be incorporated into modeling efforts.
Figure 10: Distribution of petal-centerline fractures in the portion of well 58A-10 with available image log data. Key attributes such as rock strength, loading boundary conditions, and borehole geometry are represented qualitatively by the following proxies: Rock strength: rock type, sonic velocity ($V_p$), resistivity, Breakout width, rate of penetration (ROP); Loading parameters: weight on bit (WOB), deviation from vertical, breakout width; Borehole geometry: bit (1 through 11 for each drill bit used), deviation from vertical. Note that a key attribute missing in this analysis is the variation of the mud-pressure during drilling. The first panel provides the binned distribution of petal centerline fractures within 20 ft bins and as the percentage of the depth drilled by an individual bit that contains petal-centerline fractures. The following panels are: rock type, WOB, ROP, $V_p$, Resistivity, Gamma Ray (GR), Deviation from vertical, Breakout (BO) Width.

2.9 References
Volume 3

Final Report for the Portion of the Project Focused on the Desert Peak Geothermal Field

June 15, 2012

Creation of an Enhanced Geothermal System through Hydraulic and Thermal Stimulation

DE-FC07-01ID14186

Peter Rose¹, Principal Investigator; Steve Hickman², Co-Principal Investigator; Nick Davatzes³, Co-Principal Investigator, Tianfu Xu⁴, and Karsten Pruess⁴

¹EGI, University of Utah
²U.S. Geological Survey
³Temple University
⁴Earth Sciences Division, Lawrence Berkeley National Laboratory
1.0 Original Program Objectives

The previous objective of this cooperative agreement was to increase the injection rate into Coso well 46A-19RD from less than 10 gpm to 500 gpm at a wellhead pressure of less than 100 psi.

2.0 Modification of Objectives

The new program objectives are to support development of an Engineered Geothermal System on the margins of the Desert Peak, Nevada geothermal field. See page 64 for a statement of work for EGI’s component of the program, including a subcontract to the USGS.

3.0 Chemical Stimulation of the Near-Wellbore Formation (Rose, Leecaster, Xu and Pruess)

3.1 Objective and Approach

Removal of calcite scaling from wellbores is commonly accomplished by injecting strong mineral acid (such as HCl). Strong acids tend to enter the formation via the first fluid entry zone, dissolving first-contacted minerals aggressively while leaving much of the rest of the wellbore untreated.

An alternative to the mineral acid treatment is the use of chelating agents such as ethylenediaminetetraacetic acid (EDTA) or nitrilotriacetic acid (NTA). Such agents have the ability to chelate (or bind) metals such as calcium. Through the process of chelation, calcium ions are solvated by the chelating agent, driving calcite dissolution. The kinetics of calcite dissolution using chelating agents is not as fast as that using strong mineral acids. The lower dissolution rate allows the chelating agent to take a more balanced path through the formation and to more evenly dissolve calcite in all available fractures.

The objective of this task is to demonstrate through laboratory experiments and through numerical modeling the dissolution of silica, silicate, and calcite minerals in the presence of a chelating agent (NTA) at high temperature and pH. Results indicate that the injection of a high-pH chelating solution results in dissolution of both calcite and plagioclase minerals, and avoids precipitation of calcite at high temperature conditions. Consequently reservoir porosity and permeability can be enhanced especially near the injection well.

3.2 Accomplishments

3.2.1 Laboratory Experiments

A laboratory investigation of calcite and silica dissolution at high temperature using a high pH solution with NTA was performed using the flow reactor shown in Figure 1. The reactor flow cell was 6 inches long with a 1-inch internal diameter. The top 3 inches (7.62 cm) were filled with calcite chunks (30 g limestone) and the bottom 3 inches with silicate glass beads (or silica or quartz for different experiments). Water was injected from the top of the reactor with a flow rate of $3.333 \times 10^{-5}$ kg/s (2 ml/min). Experiments were conducted for a temperature range from
150 to 300°C. The injection water was prepared by adding Na-NTA reagent and NaOH to distilled water; the resulting injection water had a NTA\(^-\) concentration of 0.1 mol/kgw (w denotes H\(_2\)O). A high value of pH (pH = 11.5) was used because the maximum value of pH decreases with temperature. (The highest pH possible at 150°C is 11.63, while at 300°C it is 11.3). Measured total amounts of silica and calcite dissolved (in percent) after each experiment are presented in Figures 2 and 3. Each data point represents one experiment at a constant temperature. Most experiments were performed for a duration of 6 hours. For experiments with less duration time, the amount of dissolution was multiplied by a factor. For example, for a 3-hour experiment, the dissolution amount was multiplied by a factor of 2.

![Figure 1: Schematic drawing of the high-temperature flow reactor](image)

**3.2.2 Numerical Model Calibration Based on Laboratory Data (Xu and Pruess)**

A 1-D model using TOUGHREACT was developed in order to simulate the dissolution experiment described above. Experimental data are then compared to model outputs and the model was calibrated as necessary to match the data. Such an approach will ultimately lead to improved forward-modeling of mineral dissolution in geothermal formations where operational parameters are more complex and varied.

**Silica Dissolution**

The following expression was used for the silica dissolution model:
\[ r = A k_{25} \exp \left( \frac{-E_a}{R} \left( \frac{1}{T} - \frac{1}{298.15} \right) \right) \left( 1 - \frac{c}{K} \right) \]

where \( r \) is silica dissolution rate (moles per unit mineral surface area and per unit time, \( \text{mol/m}^2/\text{s} \)), and \( c \) is the dissolved silica (\( \text{SiO}_2 \)) concentration (\( \text{mol/kg}_w \)). To use this rate expression, three parameters \( A, k_{25} \), and \( E_a \) need to be solved for by calibrating with measured silica dissolution data. We used a reactive surface area of \( A = 98 \text{ cm}^2/\text{g} \), which is calculated by assuming a cubic array of truncated spheres (Sonnenthal, 2005). A large number of simulations corresponding to temperatures of 120, 140, 160, 200, 230, 250°C were performed. The simulated total amounts of silica dissolved were matched to measurements by adjusting values of \( k_{25} \) and \( E_a \) through a trial and error method.

Three fitted curves are presented together with measured data in Figure 2. Curve 1 has \( K_{25} = 1.05 \times 10^{-8} \text{ mol/m}^2/\text{s} \) and \( E_a = 39 \text{ kJ/mol} \), which fits well with measured silica dissolution data for temperature range from 160 to 250°C. Curve 2 has \( K_{25} = 1.85 \times 10^{-8} \text{ mol/m}^2/\text{s} \) and \( E_a = 33.8 \text{ kJ/mol} \), which agrees with measured glass bead data for 160 to 220°C temperatures. Curve 3 has \( K_{25} = 1.14 \times 10^{-8} \text{ mol/m}^2/\text{s} \) and \( E_a = 32.8 \text{ kJ/mol} \), which matches well with quartz dissolution data for 160-230°C temperatures. Variation of the amount of silica dissolved with temperature is reflected by the activation energy term \( E_a \).

\[ \text{Figure 2. Measured total silica dissolution together with model results} \]

**Calcite Dissolution**

Calcite is assumed to react with aqueous species at local equilibrium. Calcite dissolution is driven by the chelating processes as described above. For the example of injection solution with NTA, the following reaction occurs, \( 2\text{NTA}^{3-} + 3\text{Ca}^{2+} = \text{Ca}_3\text{NTA}_2 \). This chelating reaction is to proceed according to a kinetic rate. A simple linear kinetic rate expression for formation of \( \text{Ca}_3\text{NTA}_2 \) was used:
\[ r_{Ca} = k_{Ca} C_{NTA} \]

where \( r_{Ca} \) is the rate (mol/kg\(_W\)/s), \( k_{Ca} \) is the rate constant (1/s), \( C_{NTA} \) is NTA concentration (mol/kg\(_W\)). As with the silica dissolution kinetic rate, we used an activation energy term to describe the temperature-dependence of \( k_{Ca} \)

\[ k_{Ca} = k_{25}^{Ca} \exp \left[ -\frac{E_a^{Ca}}{R} \left( \frac{1}{T} - \frac{1}{298.15} \right) \right] \]

Two parameters: \( k_{25}^{Ca} \) and \( E_a^{Ca} \) are needed to calibrate the chelating process model (or calcite dissolution model). The simulated total amounts of calcite dissolved were matched to measurements by adjusting values of the two parameters. The fitted curve (shown in Figure 3) has \( k_{25}^{Ca} = 1.78 \times 10^{-4} \) 1/s and \( E_a^{Ca} = 10 \) kJ/mol.

![Figure 3. Measured total calcite dissolution together with model results.](image)

NTA\(^{3-}\) complexing with Ca\(^{2+}\) results in a decrease in its concentration (Figure 4) and an increase in NTA\(_2\)Ca\(_3\) concentration along the column. Ca\(^{2+}\) concentration (Figure 5) remains low, maintaining calcite dissolution. Consequently dissolved carbon concentration increases continuously.
3.2.3 Application to Desert Peak (Xu and Pruess)

To investigate the effectiveness of injecting a high pH solution of a chelating agent for the dissolution of calcite and silica minerals, we applied the chemical stimulation model to a geothermal injection well system using a mineralogical composition from the Desert Peak geothermal field.
In our model, the mineralogy was defined based on pre-tertiary unit 2 (pT2) in well DP 23-1, which is a quartz monzodiorite with 7-10 wt% quartz, 40-45 wt% plagioclase, 10-15 wt% potassium feldspar and 1-4 wt% sphene (Benoit et al., 1982; Lutz et al., 2004). A clinopyroxene and hornblende-bearing diorite directly overlies the main granodiorite intrusive body. The diorite is medium crystalline and contains primary hornblende phenocrysts with cores of clinopyroxene. The diorite is strongly propylitically altered to epidote, chlorite, pyrite and calcite, is moderately sericitized, and has also been thermally metamorphosed by the underlying granodiorite intrusive.

Initial mineralogical composition used in the modeling is summarized in Table 1. The compositions specified were based on the original crystalline rock mineralogy considering altered fracture vein mineralogy. Plagioclase was modeled using 50% low-albite and 50% anorthite. Other minerals including epidote, pyrite, and biotite were not considered in the model, because their reactions with injection solution are slow and not important for the chemical stimulation purpose.

**Table 1. Initial mineralogical compositions used in the numerical modeling.**

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Quartz monzodiorite (% in terms of solid)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quartz</td>
<td>9</td>
</tr>
<tr>
<td>Calcite</td>
<td>12</td>
</tr>
<tr>
<td>Low-albite</td>
<td>21.5</td>
</tr>
<tr>
<td>Anorthite</td>
<td>21.5</td>
</tr>
<tr>
<td>K-Feldspar</td>
<td>13</td>
</tr>
<tr>
<td>Chlorite</td>
<td>8</td>
</tr>
<tr>
<td>Illite</td>
<td>7</td>
</tr>
<tr>
<td>Others</td>
<td>8</td>
</tr>
</tbody>
</table>

**Reaction kinetics**

Table 2 lists parameters for the kinetics of mineral reactions used in the model. For quartz, specific reactive surface area and kinetic parameters $k_{25}$ and $E_a$ were taken from the calibration of the lab experiment (Curve 3 of Figure 3). Specific reactive surface areas for low-albite, anorthite, and K-feldspar are set the same as quartz. Surface area for chlorite and illite was from Sonnenthal et al. (2005), calculated assuming a cubic array of truncated spheres constituting the rock framework. The larger surface areas for these clay minerals are due to smaller grain sizes. Kinetic parameters $k_{25}$ and $E_a$ for low-albite, anorthite, K-feldspar kaolinite, chlorite, and illite were taken from Palandri and Kharaka (2004), who compiled and fitted experimental data reported by many investigators. The detailed list of the original data sources is given in Palandri and Kharaka (2004). Calcite dissolution is controlled by the kinetics of the chelating process and the calibrated parameters mentioned above were used.

**Table 2. Parameters for calculating kinetic rate constants of minerals.**

Note that $A$ is specific surface area, $k_{25}$ is kinetic constant at 25°C, $E$ is activation energy, and $n$ is the power term (Eq. 4).
Flow conditions

For the model, a simple one-dimensional radial flow model of a 120-m thick reservoir formation with an injection well was used. It consisted of 50 radial blocks with logarithmically increasing radii. The 50 blocks cover a distance of 1000 m from the wall of the drilled open hole. Only the fracture network is considered in the model, with the assumption that the fluid exchange with the surrounding low permeability matrix is insignificant for the short period of chemical stimulation. An initial fracture permeability of $5.2 \times 10^{-12}$ m$^2$ was assumed. A fracture porosity of 1% (ratio of fracture volume to the total formation volume) was assumed. The 1% volume of wall rock was included in the fracture domain, to allow minerals on the fracture wall interacting chemically with injection water. Therefore, initial porosity of the modeled fracture domain is 0.5, and permeability is $2.6 \times 10^{-12}$ m$^2$. The uncertainty on the permeability specification doesn’t affect modeling results of reactive transport and porosity enhancement (as long pressure buildup at wellbore can be afforded) because a constant injection rate was specified in the present study.

Conductive heat exchange with rocks of low permeability above and below this zone is an important process when injection temperature differs from the reservoir temperature. The confining layers are modeled as semi-infinite half spaces, and heat exchange is treated with a semi-analytical technique due to Vinsome and Westerveld (1980). Initial reservoir temperature is 210°C. An initial hydrostatic pressure of 20 MPa was assumed for about 2000 m depth.

Hydrogeologic specifications of the 1-D radial flow problem are given in Table 3.

An injection temperature of 160°C was used. Injection water chemistry was the same as in the modeling of lab experiment, which was prepared by adding NTA agent and NaOH solution to steam condensate, and had a NTA$^-$ concentration of 0.1 mol/kg$_W$, a Na$^+$ concentration of 1.5 mol/kg$_W$, and a pH of 11.5. The initial water chemistry is in equilibrium with the initial mineralogy at a reservoir temperature of 210°C. An injection rate of 10 kg/s was applied for a period of half day. Reactive transport simulations were performed for up to one day, including a no-flow period after the 12-hour injection.
Table 3. Geometric and hydrogeologic specifications for 1-D radial flow problem.

<table>
<thead>
<tr>
<th>Reservoir properties:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Permeability</td>
<td>$2.6 \times 10^{-12}$ m$^2$</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.5</td>
</tr>
<tr>
<td>Rock grain density</td>
<td>2750 kg/m$^3$</td>
</tr>
<tr>
<td>Rock specific heat</td>
<td>1000 J/kg/°C</td>
</tr>
<tr>
<td>Thermal conductivity</td>
<td>2.4 W/m/°C</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Initial and boundary conditions:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure</td>
</tr>
<tr>
<td>Temperature</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Injection conditions:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature</td>
</tr>
<tr>
<td>rate</td>
</tr>
<tr>
<td>duration</td>
</tr>
</tbody>
</table>

Results and Discussion

Injection of the high pH solution with chelating agent (NTA) results in increases in porosity along the flow path close to the injection well. Overall enhancement of porosity at different times obtained from the simulation is presented in Figure 6. Increases in porosity are mainly caused by dissolution of calcite, low-albite and anorthite (Figures 7, 9, and 10). The porosity increases to about 60% from an initial value of 50% close to the injection point. The enhancement of porosity extends to a radial distance of about 5 m.

![Figure 6. Distribution of porosity enhancements at different times obtained from the simulation (Initial porosity is 50%: half fracture space and half wall rock).](image-url)
Calcite dissolves with maximum amount of 4.8% close to the injection point (Figure 7). A small amount of precipitation occurs at the moving front because increase in temperature causes decrease in calcite solubility. Amounts of quartz dissolution are very small because of a low reaction rate at this temperature (Figure 8). Generally low-albite dissolution occurs close to the injection point due to high pH, but later its precipitation occurs along the flow path because of lowered pH and high injected Na\(^+\) concentration (Figure 9). Anorthite dissolves along the flow path because of low Ca\(^{2+}\) concentration (Figure 10). K-feldspar, chlorite, illite all dissolve close to the injection point and precipitate later along the flow path, but the amounts of their dissolution and precipitation are very small.

![Figure 7. Changes of calcite abundance (in percentage of volume fraction, negative values indicate dissolution, positive precipitation) at different times.](image)

![Figure 8. Changes of quartz dissolution (in percentage of volume fraction, negative values indicate dissolution, positive precipitation) at different times.](image)
Figure 8. Changes of quartz abundance (in percentage of volume fraction) at different times.

![Figure 8](image)

Figure 9. Changes of low-albite abundance (in percentage of volume fraction, negative values indicate dissolution, positive precipitation) at different times.

![Figure 9](image)

Figure 10. Dissolution of anorthite (in percentage of volume fraction) at different times.

![Figure 10](image)

NTA\(^3\)- concentration increases very slightly from 6 to 12 hours (Figure 11). After injection stops at 12 hours, NTA\(^3\)- is continuously complexing with Ca\(^{2+}\) and driving calcite dissolution. After 24 hours, NTA\(^3\)- is used up completely. Total dissolved carbon (mainly CO\(_3^{2-}\)) concentrations increase gradually along the flow path because of calcite dissolution.
Figure 11. Distribution of NTA$^-$ concentrations at different times obtained from the simulation.

References


### 4.0 Tracer Testing of DP Injection Wells 21-2 and 22-22 (Rose and Leecaster)

#### 4.1 Objective

The objective of this task is to determine through tracer testing the flow patterns of fluids injected at the two injectors 21-2 and 22-22 within the Desert Peak geothermal field in anticipation of the stimulation of the EGS target well 27-15. With a knowledge of the background flow patterns, it will be possible to better evaluate the results of the 27-15 stimulation.

#### 4.2 Accomplishments

On 11/6/2008, 85 kg of tracer 2,6-naphthalene disulfonate (2,6-nds) and 100 kg of tracer 1,5-naphthalene disulfonate (1,5-nds) were injected into wells 22-22 and 21-2, respectively (see Figure 12). Sampling of the five producing wells 21-1, 67-21, 74-21, 77-21, and 86-21 was initiated on 11/10/2008 and has continued since. The samples are being sent to the Tracer Development Laboratory at the University of Utah for analysis by liquid chromatography with fluorescence detection.
The return of the two tracers to 74-21 (the closest producer to the south of the two injectors) was strong and immediate. Shown in Figure 13 is the return of tracer 2,6-nds from injector 22-22 and of tracer 1,5-nds from 21-2 to this production well as a function of time. It is evident that both the first arrival and the peak tracer concentration were missed for tracer 2,6-nds by the time the first sample was taken four days after tracer injection. The first arrival of tracer 1,5-nds to 74-21
again occurred before initial sampling of the well, but a peak concentration exceeding 250 ppb was observed approximately 6 days after injection.

The well showing the next strongest returns was 67-21. Plotted in Figure 14 are the returns of tracer 2,6-nds from 22-22 and of tracer 1,5-nds from 21-2. The returns to 67-21 are delayed relative to the returns to 74-21. However, the maximum measured concentration of each tracer was less than one tenth of the maximum concentrations measured by either tracer in well 74-21.

Figure 14. Return of tracers 2,6-nds and 1,5-nds from injection wells 22-22 and 21-2, respectively, to production well 67-21.

The well showing the next strongest returns was 77-21. Plotted in Figure 15 are the returns of tracer 2,6-nds from 22-22 and of tracer 1,5-nds from 21-2. The returns to 77-21 are delayed relative to the returns to 64-21, which, in turn, were delayed relative to the returns to 74-21. Likewise, the return curves of each tracer were diminished relative to the comparable curves plotted for 67-21 in Figure 14.
Figure 15. Return of tracers 2,6-nds and 1,5-nds from injection wells 22-22 and 21-2, respectively, to production well 77-21.

The well showing the lowest tracer concentrations was 86-21. Plotted in Figure 16 are the returns of tracer 2,6-nds from 22-22 and of tracer 1,5-nds from 21-2. These return curves represent the slowest first arrivals and the lowest concentrations of any of the monitored wells.

Figure 16. Return of tracers 2,6-nds and 1,5-nds from injection wells 22-22 and 21-2, respectively, to production well 86-21.

Finally, the tracer returns to all of the wells are plotted together in Figure 17. The most striking observation is that the returns of the two tracers to 74-21 were at least 10 times greater than those to any other well. Also, it is evident that the tracer concentrations decrease and the times for the
first arrivals of peaks increase in progressing from 74-21 to 67-21 to 77-21 to 86-21. No tracer has yet been observed in samples taken from 21-1.

![Graph showing concentration over days for different tracers](image)

**Figure 17.** Return of tracers 2,6-nds and 1,5-nds from injection wells 22-22 and 21-2, respectively, to all production wells where tracer was observed.

### 5.0 Borehole Log Analysis, Fractures, Stress and Fluid Flow Prior to Stimulation of Well 27-15 (Davatzes and Hickman)

**Rationale:**
Preparing for stimulation and development of 27-15 requires a complete characterization of borehole geology, hydrology, and stress state. Elements of this evaluation include analysis of stress orientation and magnitude and the natural geologic characteristics including fractures/faults, primary structure including bedding and formation contacts, and rock properties in and around the wellbore. These data are used to determine formation characteristics including permeability, lithologic variations and physical rock properties, characterize the existing natural fracture population, design the optimal stimulation strategy, and determine the necessary stimulation pressures. Thus, this element of the study is critical to both stimulation planning and evaluation so that we can maximize the transfer value of lessons learned at Desert Peak to other EGS projects.

**Status:**
To date, all of the existing logs have been acquired and interpreted, including image logs to characterize natural fractures and stress-induced borehole failure (tensile fractures and breakouts), density and velocity logs to constrain rock strength and the vertical stress, and temperature/pressure/spinner (TPS) logs to reveal fluid entry/exit points. ALT ABI85 Borehole Televiewer logs and Schlumberger FMS image logs revealed extensive tensile fractures which were used to determine the current azimuth of the horizontal principal stresses. Fractures and bedding/foliation are also well-imaged in these images. Further analysis in conjunction with a
mini-hydraulic fracturing experiment planned just prior to stimulation will be used to determine the magnitudes of both horizontal principal stresses.

**Tasks Completed:**
- Acquisition of commercial geophysical logs
- Modification of ALT ABI85 Borehole Televiewer for use in large boreholes: Implementation and use of upgraded firmware for the ABI85
- Development of ABI85 Operation Manual
- Successful acquisition of ABI85 geophysical well log in well 27-15 (3rd attempt), including in large, washed-out intervals of this well
- Compilation of all existing well logs from well 27-15 into a common data file
- Analysis of fracture and bedding/foliation orientations
- Analysis of drilling-induced tensile fractures in the borehole wall
- Analysis of temperature logs as indicators of fluid flow zones crossing the well
- Correlation of temperature anomalies with fractures or formation boundaries in Image logs (*further analysis of geologic controls on permeable zones is on-going*)
- Additional QA of logs including: depth correlation and log orientation

**Tasks Remaining:**
- Analysis of potential drilling induced breakouts in the borehole wall
- Development of a complete stress model, which requires:
  - Conducting a mini-hydraulic fracturing test to determine the minimum principal compressive stress magnitude
  - Laboratory mechanical and physical property testing of rock formations targeted during stimulation in conjunction with analysis of wireline velocity logs to develop an *in situ* strength model
  - Integration of this strength model with observations of borehole failure and results from mini-frac test to develop a full 3-D stress model
- Using this stress model and our natural fracture analysis to determine the depth distribution and orientation of pre-existing natural fractures that will be reactivated in shear during stimulation at various injection pressures. This stress model will also be used to predict the formation breakdown pressure at which new tensile fractures would propagate, should injection pressures be allowed to exceed the least principal stress during stimulation.
- Analysis of shear failure along existing fractures induced by increased borehole fluid pressure during stimulation (requires complete stress model)
- Additional QA of logs including: porosity estimation from geophysical Litho-Density and Velocity logs
- Integration with analysis of well 23-1
- Post-stimulation analysis and evaluation of stress and structural model

**Abstract:**
A complete suite of geophysical logs has been acquired for structural and stress analysis of well 27-15 in preparation for stimulation and development of an Enhanced Geothermal System adjacent to the Desert Peak Geothermal Field, Nevada. Advanced Logic Technologies Borehole Televiwer logs and Schlumberger FMS image logs reveal extensive tensile fractures
showing that the modern minimum compressive horizontal stress, $S_{h\text{min}}$, in the vicinity of well 27-15 is oriented $115\pm19^\circ$. This orientation is consistent with the mapped dip direction of modern normal faults and with extensive sets of fractures, and some formation boundaries at depth. Temperature and Spinner surveys reveal several minor flowing fractures that are well oriented for normal slip, although over-all permeability in the well is quite low, only taking ~ 3 barrels/min injection at $\leq100$ psi. These analyses complement research by other investigators including cuttings analysis, a reflection seismic survey, pressure transient and tracer testing, and micro-seismic monitoring.

**Introduction:**

Hydraulic stimulation inevitably interacts with the natural fracture population through even slightly permeable fractures in the wellbore leading to frictional failure of connected fractures in the formation. Several studies demonstrate that this network of fractures close to frictional failure, known as the “critically stressed fractures” (Barton, 1995), appear to maintain the long-term permeability in the high temperature portions of geothermal systems. For instance, at Dixie Valley, hydraulically conductive fractures are generally part of a subset of fractures on which the ratio of shear traction driving slip is equal to the frictional resistance; so these fractures are optimally oriented and critically stressed for slip (Barton et al., 1998; Hickman et al., 1998). This implies that actively slipping (i.e., shear) fractures maintain permeability, while other fractures heal. Mode I fractures in a massive hydraulic stimulation will tend to propagate towards the surface and cooler temperatures close to the wellbore. However long term, low-pressure hydraulic stimulation below the fracture pressure increases fluid pressure along the existing network accessing the heat source and causes slip and opening along self-propping shear fractures that enhance access to the hot rock. Thus characterization of the natural fractures system and the stress state acting on them is critical to both stimulation planning and evaluation so that we can maximize the transfer value of lessons learned at Desert Peak to other EGS projects.

Thus, preparing for stimulation and development of an EGS well requires a complete characterization of borehole geology, hydrology, and stress state (Davatzes et al., 2006). Elements of this evaluation include analysis of stress orientation and magnitude and the natural geologic characteristics including fractures/faults, primary structure including bedding/foliation and formation contacts, and rock properties in and around the wellbore. These data are used to determine formation characteristics including the distribution of permeability, lithologic variations and mechanical rock properties, and to characterize the existing natural fracture population and its tendency to slip during stimulation.

A complete suite of geophysical logs has been acquired for structural and stress analysis of well 27-15 in preparation for stimulation and development of an Enhanced Geothermal System adjacent to the Desert Peak Geothermal Field, Nevada. Once completed, this well will provide pressure support to the geothermal field. Logs acquired to date include image logs to characterize natural fractures and stress-induced borehole failure, density and velocity logs to constrain rock strength and the vertical stress, and temperature/pressure/spinner (TPS) logs to reveal fluid entry/exit points. Advanced Logic Technologies Borehole Teviewer logs and Schlumberger FMS image logs reveal extensive tensile fractures showing that the modern minimum compressive horizontal stress, $S_{h\text{min}}$, in the vicinity of well 27-15 is oriented $115\pm19^\circ$. Further analysis in conjunction with a mini-hydraulic fracturing experiment planned just prior to stimulation will be used to determine the magnitudes of both horizontal principal stresses.
Figure 1: Mapped fault traces in the vicinity of the Desert Peak Geothermal Field with overlain orientation of SHmax inferred from observations of borehole failure in wells 27-15 and 23-1. Analysis of stress directions in well 23-1 was conducted by GMI. Fault traces mapped by Jim Faulds.

2. ABI85 and FMS description

2.1 Methods of Image Log Analysis:

FMS and BHTV logs obtained from Desert Peak well 27-15 were used in combination to interpret the orientation of bedding, lithologic transitions, and the orientation and distribution of fractures. In addition, the stress state in the geothermal field, which acts on fractures and bed boundaries alike, was also investigated by mapping the orientation and occurrence of borehole failure manifested as tensile fractures in the borehole wall (see Moos and Zoback, 1990; Zoback et al., 2003; Davatzes and Hickman, 2005, in press). Whereas the best image quality over large intervals of the borehole was achieved with the FMS, FMS image logs provided very limited pad coverage due to the large circumference of the borehole wall in the from ~12.25 to >21.9 in. in diameter with an approximate mean of ~14.5 in. Thus on average, the pads only revealed 9-10% of the borehole circumference. BHTV images afford much greater azimuthal coverage, but as illustrated in Figure 2, poor borehole conditions lead to intervals of poor to unusable image data. Software and Firmware for the ABI85 were modified for deployment in large boreholes as a collaborative effort between ALT, the U.S. Geological Survey, and Sandia National Labs. The
Upgraded BHTV image with enhanced formation echo finding and listening time allowed much of the more in-gauge portions of the borehole to be imaged.

2.2 Image Log Analysis of Bedding, Foliation, and Natural Fractures

Combining the different attributes measured by the FMS and BHTV (Davatzes and Hickman, in press) enabled bed packages to be distinguished and especially aided in distinguishing bedding and foliations from fractures. Criteria for distinguishing beds from fractures included:

1. Systematic orientation of planes
2. Alternating zones of distinct resistivity in FMS or reflectivity in BHTV (especially when correlated)
3. Closely spaced, sub-parallel traces

These observations are integrated with existing analyses of cuttings provided by Lutz (2005) and other geophysical logs including measurements of P-Wave Sonic Velocity ($V_P$), Rock Density ($\rho_D$), Natural Gamma Ray Log (GR), and the measured Rate of Penetration (ROP) during drilling (Figure 3) to reveal the precise locations of formation transitions and additional details about their nature (such as angular unconformities).

As a first order control on our interpretation, we ranked the quality of the image logs and plot them alongside all analyses. In addition, we ranked the quality of natural fracture picks on a scale from A to C. A indicates the highest quality, least ambiguous pick derived from a structure represented as a continuous trace along the borehole wall and with a relatively large apparent aperture. Structures assigned a quality ranking of C required a more subjective interpretation, usually involving connecting discontinuous or ambiguous line segments to define the structure trace. Conservative picking in this study probably underestimates the total number of fractures, but leads to a more reliable analysis of structure orientation and distribution. Together, these steps us to distinguish the interpretability of the logs and avoid over-interpreting areas that for instance show low fracture density. In general, results of this three tiered approach measure a conservative minimum fracture density.

For high quality fracture picks we also measured the apparent aperture, or thickness, of the fracture as seen in the image log. Apparent aperture was estimated as the thickness of a zone of relatively high conductivity in the FMS image or a zone of low amplitude in the BHTV image. Although apparent aperture can be proportional to true fracture aperture in both types of logs, the measured thickness does not simply equate to the hydraulic or mechanical fracture aperture (for details see Cheung, 1999; Davatzes and Hickman, in press).
In both wells, the stress orientations are consistent with normal slip on a set of ESE and WNW dipping, NNE-SSW striking normal faults (Figure 1). This includes the trace of the Rhyolite Ridge Fault Zone that outcrops in fractured and altered basalt in the wall of the well 27-15 mud pit. Most formations imaged in the televiewer and FMS logs include sub-populations of fractures sharing the modern normal faulting orientation; however, fracture density is strongly related to rock type and can vary significantly across formation boundaries (Figure 3). Consequently, like the normal faults mapped on the surface, many of the fractures seen in the image logs have orientations consistent with normal slip based on the orientation of $S_{\text{hmin}}$. (see Figure 3, “Fracture picks + tensile fractures” panel).

### 2.3 Stress Orientation from Borehole Failure:

Concentration of tectonic stress around the free surface of a borehole can induce failure of the rock adjacent to the borehole wall. Field studies have demonstrated that these induced structures reliably record the orientations of the horizontal principal stress axes (see Moos and Zoback, 1990; Zoback et al., 2003; Davatzes and Hickman, 2005). To date we have mapped the formation of tensile fractures in the image logs of DP27-15. Tensile fractures in the borehole wall occur where the stress concentration around the free surface of the borehole wall and thermal stress due to cooling of the borehole wall produce a tensile “hoop” (or circumferential) stress that exceeds the tensile strength of the rock. Tensile fractures were only picked where they occurred as pairs, which also provided a strict quality control criterion. Mean orientations of $S_{\text{hmin}}$ are calculated by averaging the orientation of induced structures weighted by their cumulative lengths.

The image logs were checked against borehole deviation surveys and other overlapping image logs to verify accurate image orientations. These deviation surveys were also used to correct the apparent strike and dip of natural fractures intersected by the borehole to their true
strike and dip. Borehole deviation from vertical over the interpreted intervals range from 2° to 8° that allowed us to neglect corrections required for highly deviated boreholes (Peska and Zoback, 1995). We also note that the orientation of the horizontal principal stresses do not vary with the deviation angle or deviation direction. Following the method of Davatzes and Hickman (2005) the orientation of $S_{\text{hmin}}$ was determined from the average of pairs of tensile cracks. Tensile fractures were only picked when they occurred as pairs, which also provided a strict quality control criterion. Mean orientations of $S_{\text{hmin}}$ are calculated by averaging the orientation of induced structures weighted by their cumulative lengths.

Extensive observations of tensile fracturing in the image logs from well 27-15 indicate that $S_{\text{hmin}}$ is oriented 114±17°. Previous work in well 23-1 located 1.3 miles E-SE of well 27-15 has shown that $S_{\text{hmin}}$ from drilling induced tensile fractures and breakouts is approximately 119±15°, with a subset oriented 128±13° (Figure 1, 3 and 4; Note that $S_{\text{Hmax}}$ – as shown in these figures -- is oriented 90° from $S_{\text{hmin}}$). Thus, there is excellent agreement in stress orientations obtained between wells 27-15 and 23-1. Based on maps of normal faults and the similarity between normal fault dip direction and $S_{\text{hmin}}$ azimuth, we tentatively assume that there is a normal faulting stress regime in the vicinity of both of these wells. However, this a priori assumption cannot be verified without direct measurement of the horizontal stress magnitudes; thus the potential role of strike-slip faulting during fracture stimulation cannot yet be assessed. Although the horizontal stress azimuth is fairly uniform, several minor rotations of the horizontal stresses are also seen which might reflect recent fault slip. Modeling of these stress rotations in conjunction with results from the planned mini-hydraulic fracturing test will be used to provide additional constraints on stress magnitudes and the proximity to natural fractures to frictional failure.

Well 27-15 is enlarged over much of the existing open-hole section, likely due in part to borehole breakout formation. Although there are possible indications of breakout having formed at some depths in the image logs, the enlargement of the borehole from 12.25 inches to more than 20 inches has degraded image quality and limited our ability to identify breakouts with confidence and use their width to constrain $S_{\text{Hmax}}$ magnitudes. Given the identification of breakouts in well 23-1 by the preceding GMI analysis and the current state of 27-15, it is highly likely that breakouts will occur and be imaged if a sidetrack is drilled off of well 27-15 and then logged with the ABI85 televiewer.
Figure 3: Compilation of well log data and analysis to date. Possible stimulation intervals are indicated by heavy vertical red lines. The geologic formations pierced by the well are indicated as horizontal regions of constant color based on analysis by Lutz (2005). In this and all other figures, the azimuth of features in the image log have been corrected for deviation of the borehole from vertical and corrected to true North. Data includes (from left to right):

- **Temperature logs:**
  Analysis of the logs includes filtering and smoothing to remove measurement artifacts or improve temperature resolution. Data that has been smoothed is distinguished in the legend. Data presented are:
  - Temperature gradient
  - Differential temperature
  - Identified permeable zones

- **Spinner log under injection at 3 gallons/minute**

- **Caliper log including the nominal bit size in the open hole interval**

- **Image log quality, which impacts the completeness of vertical and azimuthal sampling of fractures, formation contacts, beds, and borehole wall failure**

- **Modified Tadpole plot:** Plots Fracture dip direction versus depth. The head of the tadpole indicates the dip azimuth and the tail of the tadpole indicates the dip of the fracture plane from horizontal. The colors of the tadpoles reflect the quality of the pick; in other words how well constrained the thickness and orientation of the fracture are. Also plotted are the:
  1. deviation direction (solid green line),
  2. FMS pad 1 azimuth (dashed dark green line),
  3. direction of \( S_{\text{min}} \pm 1 \) standard deviation: \( -114^\circ \pm 17^\circ \) (vertical blue dashed lines and high-lighted yellow regions),
  4. the picked tensile fractures, (scaled to their vertical extent (red lines),
  5. \( S_{\text{min}} \) direction from pairs of tensile fractures (blue diamonds).

- **Fracture frequency per five meter bins (color coded by pick quality)**

- **Fracture “Apparent Aperture” / “Thickness”**

- **Tadpole pot of bedding or foliation with ancillary data.**

- **Normalized Natural Gamma log**

- **Sonic velocity (light blue) and sonic (blue) and density (red) derived porosity**

- **Rate of penetration**

- **Deviation from vertical**
Figure 4: Summary of stress directions and fracture orientations in potential stimulation intervals (explanation on following page).
3 Temperature-Pressure-Spinner Analysis of Fluid Flow

3.1 Methods of TPS Analysis

Static and injecting (3 barrels/minute) TPS logs reveal minor pre-stimulation fluid exit/entry points within an extensive near-isothermal zone extending from approximately 3,000 ft MD to total depth at 5,627 ft MD below ground level (Figure 3). As described in more detail by Davatzes and Hickman (in press) anomalies are identified from local perturbations in temperature gradient or absolute temperature after the data is filtered and smoothed, as illustrated schematically in Figure 5.

![Figure 5: Conceptual model for thermal anomalies associated with upward flowing hot fluids (top) and downward flowing cool fluids (bottom) associated with buoyancy-driven fluid flow along a fracture and then either up (hot water) or down (cold water) the borehole (see Davatzes and Hickman, 2008, for details).](image)

3.2 Fluid Flow from TPS Analysis

Comparison of static equilibrated and non-equilibrium temperature logs helps distinguish flow zones which are connected to the larger-scale naturally permeable network, as these features have a pronounced, persistent impact upon the borehole thermal profile. Temperature anomalies associated with short-term fluid injection or recently disturbed (non-equilibrium) temperature logs indicate fractures that may host significant local permeability but are isolated from the larger hydrothermal system. Temperature anomalies are indicated in Figure 3 by red and yellow diamonds. Analysis of these temperature logs is more sensitive to minor fluid inflow and outflow and, thus, tends to identify more permeable zones than spinner logs. These local perturbations are illustrated in Figure 5 (Sorey, 1971; Drury et al., 1984; Drury and Jessop, 1987; Cornet, 1989; Barton et al., 1995; Barton et al., 1998; Ito and Zoback, 2000; Evans et al., 2005). These latter two relationships are exploited in the following analysis to recognize zones of permeability in well 27-15.

A step in the spinner log reveals the most significant, although still minor, fluid exit point during injection at 3 barrels/minute at a measured depth of ~4750 ft MD at less than 100 psi wellhead pressure (Figure 3). This zone is also associated with a persistent temperature gradient and ΔT anomaly as seen in equilibrated temperature logs. This anomaly occurs at the transition from shale to diorite, and is also associated with an increase in illite-chlorite content and quartz alteration at approximate 4737 ft MD (Figure 3 and 6). Several additional permeable zones are evident in older static temperature logs. Some of the more significant short wavelength anomalies in the open-hole interval occur at: 3054 ft, 3360 ft, 3497 ft, 3535 ft, 3777 ft, 4225 ft,
4394 ft, 4580 ft, 4737 ft, and 5142 ft MD. Several of these anomalies — i.e., 4225 ft and 4850 ft MD, and less significantly at ~4000 ft MD -- appear to be associated with possible rotations of the horizontal principal stress that may indicate an association with recent slip on nearby fractures.

4. Discussion

At shallow depths, a high temperature gradient persists from the water table to ~3600 ft MD indicating relatively low permeability. The transition from shallow high temperature gradient to near isothermal conditions at a depth of ~3500 ft MD corresponds to a mineralogical transition from Smectite to Illite-Smectite to Illite dominated clays (Figure 6), consistent with cap rock alteration (Davatzes and Hickman, 2005) producing and maintaining low permeability.

Static and injecting (3 barrels/minute) TPS logs reveal minor pre-stimulation fluid exit points associated with an extensive near-isothermal zone from approximately 3,500 ft MD to total depth at 5627 ft MD. The most pronounced exit point indicated by a step in the spinner log and a larger, persistent temperature perturbation occurs just above the transition from shale to diorite, and is also associated with illite-chlorite and quartz alteration at approximate 4800 ft MD. This region also contains fractures revealed in the image log (Figure 3). The remaining relatively minor temperature anomalies correlate with either rock type transition or fractures.

Figure 6: Rock type and alteration mineralogy of Well 27-15. (from Lutz, 2005)

Previous work in well 23-I to the east has shown that $S_{\text{min}}$ from drilling induced tensile fractures and breakouts is approximately $119\pm15^\circ$, with a subset oriented $128\pm13^\circ$. In both wells, the stress orientations are consistent with normal slip on a set of ESE and WNW dipping, NNE-SSW striking normal faults. This includes the trace of the Rhyolite Ridge fault zone that outcrops in fractured and altered basalt in the wall of the well 27-15 mud pit. The image logs also reveal extensive sets of fractures consistent with the orientation of mapped normal faults. Consequently,
like the normal faults, many of these fractures have orientations consistent with normal slip based on the orientation of $S_{\text{min}}$ (Figure 1). However, without a mini-hydraulic fracturing test and rock mechanics data from the formation to be stimulated, we currently lack enough information to determine under what injection pressure conditions these fractures would be reactivated in shear, and the total range of fracture orientations active in the current stress state susceptible to stimulation.

Currently several stimulation intervals are being considered on the basis of borehole condition, completion strategy and the availability of hydraulically accessible fractures well-oriented for slip in the modern stress state.

1. **Shallow interval: 3000 to 3500 feet MD below ground level and adjacent to the current casing shoe (Figures 3 and 4)**
   This interval hosts two or three large temperature anomalies indicating permeable zones that are not expressed or are only slightly expressed in the spinner response. The borehole is enlarged and variable in this interval. The fracture system is most poorly characterized here due to the poor image log quality resulting from borehole enlargement. Nevertheless, there are a significant number of fractures in this interval that appear well oriented for normal faulting in the present stress field.

2. **Intermediate interval: 4500 to 5000 feet MD below ground level (Figures 3 and 4)**
   This interval hosts the highest permeability zone (4837 feet MD) encountered by the borehole and several additional permeable zones. The highly permeable zone is characterized by high fracture density and fractures with significant apparent aperture that appear well-oriented for normal slip. This permeable zone also coincides with a major lithologic transition, which is associated with a change in rate of penetration (ROP), natural gamma logs, the density and velocity logs, and the dip of primary anisotropy due to bedding or foliation. This permeable zone might also be associated with a stress rotation of nearly 90°, however data are limited over that interval.

3. **Deep interval: 5300 to 5600 feet MD below ground level (Figures 3 and 4)**
   This interval hosts several minor permeable zones and overall lower fracture density. The interval is characterized by relatively uniform drilling ROP, sonic velocity, and density porosity that together indicate good formation integrity. The presence of a change in dip direction at 5290 feet MD (Figures 3) might indicate either an erosional angular unconformity or a fault juxtaposing units of distinct dip. This location is associated with a minor temperature anomaly in some temperature logs. There are some fractures in this interval that are well oriented for normal faulting in the present stress field, albeit not as many as seen in the shallower two intervals.

4. **Conclusion**
   Fractures that appear well-oriented for normal slip exist throughout the well consistent with normal faults at the surface and the orientation of $S_{\text{min}}$. At all potential stimulation intervals, well-oriented fractures and temperature anomalies indicate the presence of fractures accessible to stimulation for self-propping shear failure. However, direct examination of the faulting regime and the related magnitudes of fluid pressure at which slip will be induced by have not been determined in the absence a mini-hydraulic fracturing experiment coupled to analysis of breakout width and rock strength.

**Acknowledgments**
We would like to acknowledge contributions by Joe Henfling and Dennis King of Sandia National Lab for support during well logging operations, maintenance and modification of the ABI85; Stuart Johsnon, Peter Drakos, and Mark Tibbs of Ormat; Joe Svitek of the U.S. Geological Survey for ABI85 maintenance and field deployment; the support of the DOE.

6. References
Lutz, S., 2005, personal communication from meeting notes: January 31, 2008 at Geothermics.
Moos, D. and Zoback, M.D., 1990, Utilization of observations of well bore failure to constrain the orientation and magnitude of crustal stresses: Application to continental, deep sea drilling project, and ocean drilling program boreholes: Journal of Geophysical Research, v. 1000(B), p. 12791-12811.
APPENDIX A

Table of Geophysical Well Logs used in analyses to date

Well 27-15 in the Desert Peak Geothermal field has been repeatedly logged since its initial drilling in 2003. Currently we possess a suite of Temperature-Pressure-Spinner (TPS), Sonic Velocity, Litho-Density, Natural Gamma, Image logs including Formation Micro-Scanner (FMS) and ABI85 Borehole Televiewer, and Mud Log data. Additional information on lithology and mineralogy has obtained by Sue Lutz and Joe Moore from analysis of cuttings. These data sets, their acquisition date, and relevant datums are summarized in Table 1.

Key remaining data gaps for the analysis of stress include obtaining relevant rock mechanics data from the formations to be stimulated and a mini-hydraulic fracturing measurement.

Table 1: Database of Geophysical Well Logs in Desert Peak Well 27-15
Database of Desert Peak Well 27-15 Geophysical Well Logs

**Basic Well Parameters**
- **GL**: 46 ft
- **KB**: 22 ft (Schumacher log), 28 ft (original Mud Log)
- **Casing Size**: 2305 mm (from Mud Log, no relative to 28 ft KB)
- **Spud Date**: 2003 09 09
- **Mud Logging Dates**: 2003 08 28 to 2003 10 04
- **Bit Size**: 12.25 in (from 3015 to 3009)
- **Bit**: 18 SRM

**Field Notes from Spud on 2000 10 25-26**
- MD of Range above 2 in (2.2 ft)
- MD of Logging below 2 in (2.2 ft)
- MD of Range above 2 in (2.2 ft)
- MD of Logging below 2 in (2.2 ft)

**Magnetic Declination**: 14.3262 (2003 09 13)

<table>
<thead>
<tr>
<th>File Name</th>
<th>File Type</th>
<th>Logging Date</th>
<th>Designation in WellCAD Master File</th>
<th>Ground Level (GL)</th>
<th>Elevation (ft)</th>
<th>KB Elev. (ft)</th>
<th>Datum Relative to GL</th>
<th>Top Depth</th>
<th>Bottom Depth</th>
<th>Quantities Logged (Units)</th>
</tr>
</thead>
<tbody>
<tr>
<td>11663898 DESERT PEAK 27-15 HLD-GR_MAK_FINAL logs</td>
<td>LAS</td>
<td>2007 04 07</td>
<td>Sch-0</td>
<td>4879</td>
<td>4781</td>
<td>22</td>
<td>3031</td>
<td>Depth %</td>
<td>Depth %</td>
<td>Density, Porosity, Caliper, Gamma Ray, EFM, EFP, SFE, EOM, IR, OAP, DTM, DMR, DMT, DME, DMR, DR, DMR</td>
</tr>
<tr>
<td>11663898 DESERT PEAK 27-15 QSLT-GR_MAK_FINAL logs</td>
<td>LAS</td>
<td>2007 04 07</td>
<td>Sch-10</td>
<td>4879</td>
<td>4781</td>
<td>22</td>
<td>3031</td>
<td>Depth %</td>
<td>Depth %</td>
<td>Density, Porosity, Caliper, Gamma Ray, EFM, EFP, SFE, EOM, IR, OAP, DTM, DMR, DMT, DME, DMR, DR, DMR</td>
</tr>
</tbody>
</table>

**Hole**

- **SPUD**: 2003 08 28
- **TPR**: 2003 09 09
- **TSP**: 2003 10 04
- **DP27-15 TPS etc below 3000 ft pdf.pdf**: 2008 04 16

**Mud Log**

- **ROP2003.pdf**: 2003 08 09
- **ROP2003.pdf**: 2003 08 09

**Drillstem Test**

- **DP27-15 TPS etc below 3000 ft pdf.pdf**: 2008 04 16

**Log**

- ** customer_drill.no-de.gdf**: 2003 08 13
- ** customer_drill.no-de.gdf**: 2003 08 13

**Notes**

- Mud log offset from some TPS and from Schumacher Geophysical logs by 6 ft.
APPENDIX B

B. 0 Temperature Analysis

Temperature profiles provide insights into several fundamental properties of geothermal fields: (1) Static temperature ($T$) profiles in geothermal systems record heat flux through the crust and the relative role of conductive and advective heat transport distinguished by the temperature gradient; (2) active entry of relatively hot or cold fluid appear as short wavelength temperature perturbations in disequilibrium temperature logs or injecting TPS logs and reveal small scale regions of enhanced permeability and storativity, whereas (3) equilibrated temperature logs reveal naturally active flow zones where they enter the well and indicate extensive permeable zones or fracture connectivity. These local perturbations are illustrated in Figure 2 (Sorey, 1971; Drury et al., 1984; Drury and Jessop, 1987; Cornet, 1989; Barton et al., 1995; Barton et al., 1998; Ito and Zoback, 2000; Evans et al., 2005). These latter two relationships are exploited in the following analysis to recognize zones of permeability in well 27-15.

Two methods were used to identify potentially significant thermal anomalies from precision temperature logs in well 27-15. The first is the local differential temperature (Figure B1), $\Delta T$, versus depth (Ito and Zoback, 2000), obtained by subtracting the temperature obtained from two differently sized smoothing windows applied to the absolute temperature logs. Using a Gaussian weighted mean in a large depth window minimizes local anomalies and provides a background temperature that can be used to identify local anomalous temperatures. Thus, an average temperature from a large Gaussian averaged window, $M_L$, is subtracted from a small window, $M_S$ (values in Table B1). However, temperature anomalies with wavelengths similar in scale to the smoothing window will be accentuated and may produce spurious anomalies in the $\Delta T$ analysis. The second method is the local temperature gradient (Barton et al., 1995; Barton et al., 1998) calculated as the depth derivative of temperatures obtained from the $M_S$ window (Figure B1).

Figure B1: Conceptual model for thermal anomalies associated with upward flowing hot fluids (top) and downward flowing cool fluids (bottom) associated with buoyancy-driven fluid flow along a fracture and then either up (hot water) or down (cold water) the borehole. (see Ingebritsen et al., 2006).

![Figure B1](image-url)
Table B1: Temperature Data and Processing

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Wellaco Temp. Log</th>
<th>ABI85 Temp. Log</th>
</tr>
</thead>
<tbody>
<tr>
<td>Data spacing [m]</td>
<td>0.3 – 1 m</td>
<td>~0.01 m</td>
</tr>
<tr>
<td>Data precision</td>
<td>0.001°C</td>
<td>0.00625°C</td>
</tr>
<tr>
<td>Gaussian Smoothing Window Step Distance</td>
<td>2 m</td>
<td>0.25 m</td>
</tr>
<tr>
<td>Large Smoothing Window [M_L]</td>
<td>70 m</td>
<td>70 m</td>
</tr>
<tr>
<td>Large Smoothing Window [M_S]</td>
<td>10 m</td>
<td>0.5 m</td>
</tr>
</tbody>
</table>

B.1 Wellaco Logs

Commercial well logs have been obtained several times between 2003 and 2008. Before the temperature logs are interpreted significant care has to be taken in the processing of the data. For commercial Wellaco logs, the principal concerns are imprecise depth control on temperature measurements that produce large variations in the distance between temperature measurements. Since these differences in depth are associated with wildly varying estimates of temperature gradient between adjacent points, it is most likely that these variations in data spacing due not reflect the actual sampling depths but errors in depth measurement (Figure B2). In some cases this error is systematically distributed; however, this is not generally true. A practical means of minimizing the impact of this error is to: (1) filter out all data points that due not meet a strict depth spacing criterion, i.e., all data that falls outside a specified range of depth spacing is eliminated from any calculations; (2) the data can be smoothed to resample and produce uniform spacing among points (Figure B3). We used both of these methods prior to calculating either the temperature gradient or ΔT.

Figure B4 reference
Figure B2: Variation in sampling interval of logs acquired by Wellaco for QA. Significant errors in the analysis of temperature gradients and temperature shifts indicative of fluid flow in these logs result from low precision of the measured depth during logging. (a) Shows the depth spacing of between adjacent points among the more than 11500 temperature measurements among five logging runs from 2003 to 2008. (b) Shows a relative frequency of the depth spacing of temperature measurements. (c) Temperature profiles from the five temperature logs analyzed.
Figure B3: Evaluation of smoothing parameters for calculation of temperature gradient.
3.2 Temperature Recorded by the ABI85

In the ABI85, the PT100 thermistor located on the exterior of the tool records a resistivity measurement each time the tool completes an azimuthal scan of the borehole wall. The resultant data is converted to produce data quantized at 0.00625 °C. Thus, the measured temperatures are unequivocally associated with an image of the borehole wall and any potential sources of flow such as fractures or formations. However, the temperature quantization in the ABI85 is very small compared to the sample interval and this produces anomalous estimates of temperature gradient between adjacent points. Re-sampling and smoothing using a moving Gaussian smooth window (Hamming, 1998) effectively removes this problem. Gaussian smoothing windows minimize edge effects resulting from the smoothing process and emphasize the temperatures at the window center which helps preserve anomalous perturbations in temperature. In addition, Gaussian smoothing of ABI85 data takes advantage of the very high data density to enhance the effective precision of the tool by about 0.5 decimal places by averaging across many temperature samples that toggle by the quantization across the actual temperature due to rounding error. The step interval, and most importantly, the size of the smoothing window is optimized by systematically testing different window dimensions (Figure B5; Table B1).
Figure B5: Smoothing parameters for over-sampled ABI85 BHTV data for QA; example from one of five ABI85 temperature logs: (a) Temperature profile showing the raw temperature, and Gaussian smoothed temperature for different window sizes. Window sizes are explored as absolute length values, or distances in multiples of the data spacing. (b) Corresponding temperature gradient profile. (c) and (d) zoomed in views to show the quantization of temperature relative to data spacing and its impact on the calculated temperature gradient, respectively. (e) and (f) show the respective mean and maximum standard deviation of temperature within each sample window of the raw and smoothed data for different window size.

The difference between optimally smoothed and other results is highlighted in panels 3 and 4 of Figure B6. Despite consisting of 100 measurements, a 1 meter smoothing window retains large amounts of scatter in the calculated temperature gradient. However, a 6.4 m smoothing window removes most of the noise while retaining many temperature anomalies, which are now interpreted to be geologically significant. As a quality control, results from Gaussian smoothing were compared to simpler boxcar (or moving average) smoothing in which an equally weighted mean of all points in the smoothing window is obtained and the raw data. Both quality assurance tests indicate the Gaussian smoothing procedure with an optimized window size produces the best data quality.
Figure B6: Static temperature profiles collected during ABI85 BHTV logging. (a) Measured temperature profile obtained after conversion from measured resistance in PT100 thermistor. (b) and (c) temperature gradient after Gaussian smoothing with 6.4 m and 1 m smoothing windows, respectively. (d) ΔT of optimally smoothed temperature data. (e) Caliper log from FMS (blue and red) and spinner log (gray) from injection test.
APPENDIX C

C.0 History of Logging Attempts and Tool Development in Support of Desert Peak
(Summary of work to date and outstanding issues)

In support of the Desert Peak EGS effort, three attempts were made to log well 27-15; multiple attempts were required because of adjustments of the tool to logging in large boreholes. This issue was exacerbated by (a) adverse conditions resulting from a borehole diameter that has enlarged from the initial bit diameter of 12.25 inches to more than 20 inches in some locations and roughened attenuating the strength of the returned acoustic pulse; (b) a previously unrecognized design flaw resulting from the very high temperature gradients in geothermal wells. As a result of these efforts, three problems were resolved during these logging attempts: (1) Gating of the formation echo, (2) shrinkage of the PEEK acoustic window, (3) maintenance issues. These modifications are briefly described below. (Please see appendices in the 3rd Quarter report that include further documentation of the difficulties and resulting adjustments through collaboration with ALT.)

C.1 Large Borehole Modifications to the ABI85:

The arrival of the acoustic pulse reflected from the formation must be distinguished from the initial pulse and the bounce from the acoustic window and any resulting internal noise that includes a strong multiple. The velocity of the borehole fluid and spindle oil in the acoustic head, and thus the time of the arrival of these pulses, is strongly temperature, \( T \), and pressure, \( P \), dependent. This creates two problems when logging a borehole: (1) How to distinguish the formation echo from any acoustic noise; (2) Addressing the problem that the travel time varies due to logging depth (because of \( T \) and \( P \)) and variations in borehole diameter.

Originally, the ABI85 was designed to automatically pick the returned acoustic pulse from the acoustic window and the formation. This was largely based on expected arrival times and on the relative amplitude of the returned pulse. In large, rugose boreholes, the formation echo is highly attenuated so that it has a similar amplitude to noise, including an important multiple, left in the acoustic head from the original window echo. Thus a strict criterion for echo finding based on echo amplitude might not distinguish the formation echo from noise. Furthermore, the formation echo and this multiple might overlap in two-way travel time. This situation prevents any possibility of logging wells with particular combinations of acoustic velocity in the borehole fluid and the oil in the acoustic head and borehole diameter.

Summary Initial Findings at DP 27-15

- The acoustic velocity of the oil is highly sensitive to temperature (decreasing by a factor of \( \sim 2.5 \) over a temperature change of \( \sim 170^\circ C \), despite large increases in pressure up to \( \sim 13.7 \) MPa).
- At \( \sim 158^\circ C \) in the oil of the Acoustic Head (i.e., at depth of 2077ft MD below WH), the two-way travel time to casing in a 12.25 inch casing of DP 27-15 exceeds 307.2 microseconds and is no longer recorded.
- Thus the tool could not acquire any images in the 12.25 inch cased hole below this critical temperature, or in the open hole below the casing shoe at 3015 ft MD below WH. This was a fundamental limitation of the tool as it was configured prior to upgrade, which prevented its use in imaging large diameter boreholes at elevated temperature (recall that 15 inch diameter was required in the design specifications).

Initial Recommendations
- Modify firmware, software, or hardware to allow imaging of boreholes up to 15 inches at temperatures of 275º C. (Increase wave recording time and/or change fluid in acoustic head?)

We also discovered that the period of time the tool “listens” for the formation echo, as required by the rate of spin of the mirror, was too short. In Figure C1, waveforms show gradual shift in the window return time with change in temperature in the acoustic head although the tool is stationary in casing to insure a strong reflection of the acoustic pulse. The return of the acoustic pulse from casing was recovered as the temperature in the acoustic head, $T_h$, equilibrated with the temperature of the borehole fluid, $T_f$. The echo from the casing is lost where it exceeds the original maximum recording time of 307.2 seconds inherent to the original design of the tool ABI85. The 307.2 second time length reflects the maximum time available given the original rate of window rotation. This largely resulted from the very large reduction in acoustic velocity of the oil at high geothermal gradients where increases in pressure that increase acoustic velocity could not compensate for the high rate of temperature gain at Desert Peak.

Attempts to use the automatic window finding algorithm in the advanced settings dialog box. However, after we manually entered our desired gating information, the values typically reset to some sort of default values. This prevented us from manually controlling the window finding gate. During most of the logging, and for reasons unclear to us, the window detection algorithm picked an early impulsive arrival (at 25.7 microseconds) resulting in the actual window reflection being picked as the formation echo (Figure C1b). In the field we used the Right Limit to exclude all signals less than about 200 microseconds to allow any logging at all as this problem became pervasive.

In order to address these problems, ALT in combination with analysis and recommendations by Nicholas Davatzes, Temple University, Steve Hickman, U.S. Geological Survey, and Joseph Henfling, Sandia National Lab, have modified the firmware of the ABI85 to:

1) Extend the listening time
2) Add manual controls to control the time interval in which the acoustic echo from acoustic window and the formation is identified as the largest amplitude return

This firmware modification was installed for the most recent, and successful, ABI85 logging run in July of this year. a result of the extended listening time with this software, firing rate of acoustic pulses has been reduced. The reduction of the spinning rate also increases the current draw from 100 mA to 120 mA, resulting in slightly faster internal heating to approximately 4°/hour at in a 190°C environment.
Figure C1: ABI85 Image log data with panels showing (left to right): Travel time, Amplitude, Waveforms, Two-way travel time and amplitude of auto-picked acoustic window reflection, Temperature of the borehole fluid and oil in the acoustic head, Tilt which is the deviation of the tool from vertical during logging, and Azimuth which reflects the direction in which the tool is tilted. The window arrival is the first large amplitude wave-trace, the (a) Two examples of the drift in travel time of window echo arrival (bright red thick wave-forms) and loss of casing return (smaller band to right) echo with increasing oil temperature in the acoustic head (Th) as the tool is held stationary in casing. (Two-way travel time data from ALTLogger file DP20070524T2upT2.rd.WCL). Amplitude is scaled from -200 to 200 (min = -1056, max = 992). (b) Shows the internal multiple (an echo left-over from the initial window echo) which exists above and below the water table and the formation echo, in this case from casing, that exists only after the tool is lowered past the water table.
Figure C2: Acoustic velocity in (a) the oil of the acoustic head, and (b) blue: measured and extrapolated two-way travel time of the oil-window echo (tt2), red: the casing echo (tt4), and gray: travel time in the borehole fluid (tt4 – tt2). In (a) the vertical gray region marks the temperature at which the formation echo arrived after the 307.2 micro-second travel time record of the ABI85 in the ALTLogger software. Upturn in velocity at high temperature is associated with increased pressure in isothermal zone from ~7.5 to 13.7 MPa as we continued logging to the base of the borehole. The increase in pressure was not enough to recover the formation echo within the allotted wave recording time of 307.2 microseconds. In this plot: Red circles = Two-way Casing echo travel time; Blue circles = Two-way Window echo travel time; Gray circles = Two-way Travel time in borehole fluid from window to casing and back; Magenta stars = Two-way Travel time simulation from ALT autoclave data provided in email.
Figure C3: Parameters for choosing optimal listening time as a function of borehole temperature borehole dimensions for the temperature gradient of ~ 140 °C/km experienced in the upper 1000 m of Desert Peak well 27-15 (higher temperature gradients would exacerbate the problem). (b) Acoustic velocity of pure water at the boiling point curve. Two way travel time estimated with the known velocity of the spindle oil in the acoustic head of the ABI85 for different borehole radii.
Figure C4: Example and cartoon of wave-traces showing arrivals of the acoustic window echo, the formation or casing echo, and the internal tool multiple. Two choices for modifying the time-gates used to limit the search for the formation echo are indicated: (A) Manually setting the time range to search for the window echo, (B) Manually setting an exclusion for the internal tool multiple.
Table C1: Temperature and travel time information for various tool echos:

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
<th>G</th>
<th>H</th>
<th>I</th>
<th>J</th>
<th>K</th>
<th>L</th>
<th>M</th>
</tr>
</thead>
<tbody>
<tr>
<td>N</td>
<td>Depth</td>
<td>Time</td>
<td>Echo type</td>
<td>Temperature</td>
<td>0°C</td>
<td>1°C</td>
<td>5°C</td>
<td>10°C</td>
<td>15°C</td>
<td>20°C</td>
<td>25°C</td>
<td>30°C</td>
</tr>
<tr>
<td>1</td>
<td>1</td>
<td>17</td>
<td>50</td>
<td>10</td>
<td>15</td>
<td>20</td>
<td>25</td>
<td>30</td>
<td>35</td>
<td>40</td>
<td>45</td>
<td>50</td>
</tr>
<tr>
<td>2</td>
<td>2</td>
<td>10</td>
<td>40</td>
<td>10</td>
<td>15</td>
<td>20</td>
<td>25</td>
<td>30</td>
<td>35</td>
<td>40</td>
<td>45</td>
<td>50</td>
</tr>
<tr>
<td>3</td>
<td>3</td>
<td>20</td>
<td>30</td>
<td>10</td>
<td>15</td>
<td>20</td>
<td>25</td>
<td>30</td>
<td>35</td>
<td>40</td>
<td>45</td>
<td>50</td>
</tr>
<tr>
<td>4</td>
<td>4</td>
<td>30</td>
<td>20</td>
<td>10</td>
<td>15</td>
<td>20</td>
<td>25</td>
<td>30</td>
<td>35</td>
<td>40</td>
<td>45</td>
<td>50</td>
</tr>
<tr>
<td>5</td>
<td>5</td>
<td>40</td>
<td>10</td>
<td>10</td>
<td>15</td>
<td>20</td>
<td>25</td>
<td>30</td>
<td>35</td>
<td>40</td>
<td>45</td>
<td>50</td>
</tr>
</tbody>
</table>

Notes:
- Temperature increments are in °C increments.
- Echo types include: internal echo, window, window reflection, and window multiple.
- Travel times are given in nanoseconds.
- Data is collected at 1.25 mm intervals.
C.2 Window Shrinkage

During logging at Desert Peak in early 2007, it was discovered that the PEEK acoustic window shrank during logging to the point where it nearly popped threads. This represented a significant risk of loss of the lower, pressure compensating piston assembly on the tool (which is located below the acoustic window) and resulting damage to the stepper motor spinning the mirror and the transducer generating the acoustic pulse. U.S. Geological Survey Personnel (Steve Hickman and Nick Davatzes) worked extensively with Sandia National Lab to characterize the problem. With USGS input and in consultation with ALT, Sandia designed and built a titanium “harness” (Figure C5) that secures the lower piston assembly to the upper tool across the acoustic window. The upper and lower coupling are connected via titanium rods and produce minimal loss of azimuthal coverage.

Summary of Initial Findings: Acoustic Window Shrinkage

- Threads on the upper acoustic window again became loose at the upper coupling.
- Examination of the acoustic window demonstrated that:
  - Only the upper coupling was significantly loose, i.e., would pop threads when tightened, and allows a 1-2 mm gap. It was so loose that the window and piston assembly almost dropped off the tool on the trip out of the hole. It was loose when tested in both the upper and lower couplings.
  - The lower coupling has a loose fit until tightened in the final turns. It tightens up in both the upper and lower couplings.
  - OD of upper threads is: ~78.4 mm
  - OD of lower threads is: ~78.8 mm
  - Calipers show that the window still has a constant radius
  - ID of window is 64.8 mm
  - OD of window is 74.8 mm [specs call for 74.9 mm]
  - No damage to the threads is visible and threads on upper and lower coupling were identical to visual inspection
- This window has only been used this single time in well 27-15 at Desert Peak.
- These are essentially the same set of conditions experienced with the window previously replaced in this tool.

Next Steps

- No cause for shrinkage has been isolated, although a problem with the particular PEEK batch has been suggested. We are monitoring for recurrence.
- The Sandia-built harness system is installed and used to prevent loss of the lower piston assembly.

The exact cause of the shrinkage is still uncertain. It was discovered that PEEK has a lower glass transition temperature below the temperature range experienced during logging. However, given the very low differential pressure experienced between the inside of the acoustic and the borehole fluid pressure due the action of the pressure compensating piston, these were deemed insufficient mechanisms to explain the observed shrinkage. Sandia also demonstrated that there is slight differential thermal expansion between the titanium and the peak; but again insufficient to explain the observations.

During the most recent logging run with, a Teflon coating was applied to the PEEK window as an additional barrier to any chemical reactions resulting from contact with borehole fluid. This coating was too thin to affect transition of the acoustic signal across the PEEK window. No shrinkage was observed, however there is not a general consensus as to whether the
lack of shrinkage was due to the Teflon coating or the fact that the newest acoustic window was derived from a new PEEK batch.

![Image](image1)

**Figure C5**: (a) Assembled and hanging ABI85 at well 27-15 showing new harness and Teflon-coated PEEK acoustic window (Photo Courtesy Joseph Henfling, Sandia). (b) Titanium harness used to secure PEEK acoustic window (yellow) and lower piston assembly (left) if acoustic window shrinks.

### C.3 Maintenance
During the last quarter significant additional effort by Nick Davatzes (Temple University), Steve Hickman, Joe Svitek (USGS) and Joseph Henfling, Dennis King (Sandia National Lab) has been expended to:
- Develop an Operations Manual for tool deployment and document all tool modifications
- Manage o-ring maintenance and corrosion of the pressure housing and internal wiring harness

### C.4 Calibration Stand Testing of Magnetometer
Prior to logging at Desert Peak we performed a test of the accuracy of the ABI85 magnetometer used to record the orientation of the tool during logging and any effects of magnetic fields associated with the tool. This test was conducted by suspending the tool from a non-magnetic aluminum calibration test stand and then monitoring images in a test tank. We found an effective precision of ± 2.5 degrees, with some directional variation indicating the tool carries a very weak magnetic field.

### C.5 Outstanding Issues
Several issues remain to be addressed and are being discussed with ALT including:
• Increased control of the gating of the acoustic signal for the purpose of echo detection.
• Additional real-time tools in ALTLogger software to monitor travel times during log acquisition as they change due to variation in temperature or pressure.
• Centralizers have shown a tendency to bind preventing collapse of the centralizer springs when using large springs necessary for centralization in large boreholes. When transitioning from large to small borehole diameters these springs might then break jeopardizing the tool. Several options for spring re-design for large boreholes are being considered.
APPENDIX D

Fractures by orientations by stratigraphic unit

- Altered Rhyolite Tuff
  - All Fractures: N = 567, rc = 0.125°R
  - Fm1 Fractures: N = 59, rc = 0.3638°R
  - Fm2 Fractures: N = 17, rc = 0.58835°R
  - Fm3 Fractures: N = 82, rc = 0.31449°R

- Hematite Mustone
  - All Beds: N = 735, rc = 0.1099°R
  - Fm1 Beds: N = 54, rc = 0.37796°R
  - Fm2 Beds: N = 43, rc = 0.41603°R

- Calcite Mudstone
  - All Fractures: N = 71, rc = 0.33541°R

Color bar: 20/°R

Legend:
- Yellow: 0
- Green: 10
- Red: 18
- Blue: 20

N: Number of fractures
rc: Roundness coefficient
Figure D1: Equal area, lower hemisphere, stereograms of poles to fractures and bedding/foliation for: (a) all fractures, and for fractures in (b) Altered Rhyolite Tuffs, (c) Hematite Mudstone, (d) Calcite Mudstone, (e) Metamorphosed Tuff & Dolomite Mudstone, (f) Shale, (g) Diorite, (h) Phylite, and (i) Hornfels. Stereograms (j) through (r) represent the corresponding orientations of bedding in these formations. Formations are based on analysis by Lutz (2005).

(a) All features, n = 566, Dip Direction  
(b) All features, n = 735, Dip Direction

Figure D2: (a) Rose diagram of fracture dip directions. (b) Rose diagram of bed/foliation dip directions.
APPENDIX E

Figure E1 – Shallow stimulation interval 3000 to 3500 ft6 MD below GL.
Figure E2 – Shallow stimulation interval 4500 to 5000 ft MD below GL.

Figure E3 – Shallow stimulation interval 5300 to 5600 ft MD below GL.
STATEMENT OF WORK

EGI EGS PROGRAM AT DESERT PEAK, NEVADA

A Continuation of the Cooperative Agreement:

CREATION OF AN ENHANCED GEOTHERMAL SYSTEM THROUGH HYDRAULIC AND THERMAL STIMULATION

DE-FC07-01ID14186
6.0 Project Period Expiration
September 30, 2008

7.0 Budget

<table>
<thead>
<tr>
<th>Task</th>
<th>EGI-Internal</th>
<th>Subcontract to USGS</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.1.1 Analysis of Televiewer Data and Geophysical Logs</td>
<td></td>
<td>$48,000</td>
</tr>
<tr>
<td>4.1.2 Mini-Frac of DP Well 27-15</td>
<td></td>
<td>$32,000</td>
</tr>
<tr>
<td>4.1.3 Prestimulation Tracer Test in DP27-15</td>
<td></td>
<td>$20,000</td>
</tr>
<tr>
<td>4.1.4 High-temperature mineral dissolution studies</td>
<td></td>
<td>$35,000</td>
</tr>
<tr>
<td>4.1.5 Development of a Structural Model of the Desert Peak Field</td>
<td></td>
<td>$40,000</td>
</tr>
<tr>
<td>4.1.6 Tracer Study of Existing Injection Wells</td>
<td></td>
<td>$40,000</td>
</tr>
<tr>
<td>4.1.7 Development of Stimulation Plan and Cost Estimate</td>
<td></td>
<td>$15,000</td>
</tr>
<tr>
<td>4.1.8 Phase I Reporting</td>
<td></td>
<td>$10,000</td>
</tr>
<tr>
<td><strong>Task II</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4.2.1 Stimulation of DP27-15</td>
<td></td>
<td>$20,000</td>
</tr>
<tr>
<td>4.2.2 Stimulation Analysis and Design of Circulation Test</td>
<td></td>
<td>$10,000</td>
</tr>
<tr>
<td>4.2.3 Post Stimulation Circulation, Interference and Tracer Testing</td>
<td></td>
<td>$60,000</td>
</tr>
<tr>
<td>4.2.4 Phase II Reporting</td>
<td></td>
<td>$10,000</td>
</tr>
<tr>
<td><strong>Subtotals:</strong></td>
<td>$220,000</td>
<td>$120,000</td>
</tr>
<tr>
<td><strong>Total:</strong></td>
<td>$340,000</td>
<td></td>
</tr>
</tbody>
</table>

Figure 1. EGI budget-by-task in support of the Desert Peak EGS program.

8.0 Summary of Contents

This proposal includes the work that will be conducted by EGI and the USGS in support of the EGS project at Desert Peak. Included in Appendix F is the overarching statement of work for the main Ormat/Geothermex-directed program. Appendix G includes the original statement of work and budget for the USGS/Menlo Park program that will be subcontracted to EGI.

9.0 EGI Statement of Work

9.1 Phase I

9.1.1 Analysis of Televiewer Data and Geophysical Logs; Development of Stress Field Model (see Appendix F Phase I Task 3)

The USGS/Sandia borehole televiewer will be run in well DP27-15. The televiewer data and that from the Schlumberger logs run earlier this year will be analyzed by Nick Davatzes and Stephen Hickman (USGS) to determine the stress field orientation (by evaluating wellbore failures such as breakouts and drilling-induced tensile cracks), characterize the natural fracture population (particularly in attractive lithologies near the bottom of the well) and develop the stress model to guide EGS developments at Desert Peak. Some rock strength data are already
available to contribute to this effort since the most promising units observed in well DP27-15 are same as those previously evaluated using core samples from TCH35-13. Additional rock properties data will be provided by tests of new cores collected at total depth (TD) in well DP27-15.

9.1.2 Mini-Frac of DP Well 27-15 (see Appendix F Phase I Task 5)

The plan for re-completion of well DP27-15 will include a mini-frac, which is a series of low-volume, high pressure injections designed to initiate tensile failure in the formation targeted for hydraulic stimulation. This mini-frac test will be conducted and analyzed by Stephen Hickman and Nick Davatzes (USGS). A mini-frac provides a critical measure of the magnitude of the least principal stress, and, together with observations of wellbore failures from the borehole televiewer log, sonic/density log data and core test data, enables the development of a complete three-dimensional stress model for this site. To assist with stimulation design, this model will be used to calculate the injection pressures needed to trigger shear failure (slip) on pre-existing fractures and faults seen in the image logs from wells DP27-15 and DP23-1.

9.1.3 Prestimulation Injection and Tracer Test in DP27-15 (see Appendix F Phase I Task 6)

After re-completion, a step-rate injection test will be conducted in well DP27-15 to derive pre-stimulation injectivity and estimate critical hydraulic parameters (transmissivity, storage and wellbore “skin factor”). During the first period of injection, detailed PTS (pressure-temperature-spinner) logging will be conducted to identify permeable zones in the target interval, and a tracer will be injected to characterize the pre-stimulation hydraulic connection to the existing production wells. After the PTS logging run is finished, the tool will be “parked” at a suitable depth for pressure monitoring during the duration of the test. We will inject at 3 or 4 different rates, each injection rate step long enough to obtain stabilized downhole pressures. GeothermEx and Ormat will conduct the test.

A tracer test will be carried out as part of the injection test program. The injection tests will be run long enough to disperse the tracer into the reservoir, where convective forces will transport the tracer to surrounding production wells. These will be sampled and analyzed to characterize the pre-stimulation hydraulic connectivity between the injection well (DP27-15) and the production wells in the field.

9.1.4 Detailed Evaluation of Target Formation in Core Samples (see Appendix F Phase I Task 7 for complete task description)

This task will also include laboratory tests of mineral dissolution. EGI has a high-temperature flow reactor that can be used to evaluate the reactions between target reservoir rocks and various acids, bases and/or chelating agents. Focusing on the pT2 unit, we will use core and cuttings from well DP27-15 and core material from well TCH35-13 in these tests, evaluating how the rock matrix and vein fillings would dissolve under various pressure, temperature and chemical conditions. Chemical stimulation at the Soultz EGS project has recently been used to enhance
permeability in near-wellbore formations, resulting in significant improvements in well injectivity and productivity.

9.1.5 Development of Structural Model of the Desert Peak Field (see Appendix F Phase I Task 8)

This work, which will be undertaken by Nick Davates and Stephen Hickman (USGS) with support from Ormat and GeothermEx, will be developed based on the stratigraphic work (Appendix F, Task 2) and well log analyses (Appendix F, Task 3) described above and field investigations of the Rhyolite Ridge Fault Zone. Specific attention will be paid to the extent and geometry of the target pT2 formations, and adjacent formations that are offset along fault zones. The evaluation will utilize published maps (e.g., Faulds et al., 2004; Oppliger et al., 2004; Benoit et al., 1982); stress field data from the image log data collected in wells DP27-15 and DP23-1; geophysical log data from older Desert Peak wells; and a detailed study of the surface trace of the Rhyolite Ridge Fault Zone, which appears to be a locus of commercial permeability at Desert Peak. A vein-filled fault zone unearthed when the drilling sump was excavated on the DP27-15 well pad will be mapped and evaluated. As shown in Figure 1 (Appendix F), well DP27-15 is located astride the surface trace of this fault zone.

9.1.6 Tracer Study of Existing Injection Wells (see Appendix F Phase I Task 9 for complete task description)

Wells DP21-2 and DP22-22 are currently used for injection. Tracer tests will be initiated in each of these wells (using a different tracer in each) to characterize their hydraulic connection to the production wells. These tracer tests (and that undertaken in well DP27-15) will provide important data for understanding the permeability distribution and fluid flow paths in the reservoir, which in turn assist with calibrating the numerical model of the field.

9.1.7 Develop a Stimulation Plan and Cost Estimate (see Appendix F Phase I Task 11 for complete task description)

The results of the analyses described above will be evaluated in an integrated manner to design the stimulation program. At this time, we feel it is likely that the program will consist of a chemical stimulation to enhance near-wellbore permeability, followed by a hydraulic stimulation to connect into the fault and fracture zone that is the locus of production in the Desert Peak production wells. The order of these operations may be reversed depending on the results of the tasks and analyses yet to be completed. Chemical stimulation will be undertaken if one or more the following conditions prevail:

a) cores and cuttings show extensive carbonate and/or silicate mineral veining, and tests in the high-temperature reactor yield positive results for mineral dissolution at Desert Peak temperature and pressure conditions

b) the transmissivity of the un-stimulated formation is low

c) the well has a significant positive “skin factor” indicating near-wellbore damage.
In designing the stimulation, we will build on previous DOE-supported tests and analyses of various chelating agents that are useful in both carbonate and silicate vein deposits. This will use the results of new tests conducted in EGI’s high-temperature reactor as described above in Task 7.

Since an integrated approach is needed for the stimulation, the entire team (Ormat, GeothermEx, EGI, USGS) will develop the stimulation plans together, and obtain the requisite cost estimates for implementing those plans.

9.1.8 Phase I Reporting (see Appendix F Phase I Task 12)

The team will prepare a summary report on all activities completed during Phase I. We will report the results to EGS workshops and meetings, and will publish the results in the GRC Transactions and/or Stanford Workshop Proceedings.

9.2 Phase II

9.2.1 Stimulation of Well DP27-15 (see Phase II Task 2 in Appendix F)

All needed equipment and personnel will be mobilized to the site. The hydraulic and/or chemical stimulations will be undertaken while conducting downhole pressure monitoring and real-time micro-seismic data collection and processing to monitor the evolution of the stimulation and adjust procedures as needed. An injection test will be conducted at the end of the stimulation to establish post-stimulation injectivity and hydraulic parameters (transmissivity, storage, wellbore “skin factor” and the radius of the stimulated zone). Detailed PTS logs will be run during the post-stimulation injection test to identify zones accepting injection fluid for comparison with pre-stimulation profiles.

9.2.2 Stimulation Analysis and Design of Circulation Test (see Phase II Task 3 in Appendix F)

The data collected during the stimulation will be analyzed to identify and characterize seismically and hydraulically active areas, and the configuration of the circulation test will be determined. All parties (Ormat, GeothermEx, LBNL, EGI, USGS) will participate in this task.

9.2.3 Post Stimulation Circulation, Interference and Tracer Testing (see Phase II Task 4 in Appendix F)

A test will be conducted over several months to evaluate the changes that have occurred as a result of stimulation. During this test, the stimulated well (DP27-15) may be used as an injection well, a production well, or both. The tracer testing undertaken (both in DP27-15 and the other two injection wells) before stimulation will be repeated to characterize the new pathways between production and injection wells. Samples of the circulating fluids will be collected and analyzed. The test will include downhole and/or wellhead pressure monitoring to enable the new hydraulic characteristics of the system to be determined. Pressure transient data will be collected.
during the test and after shut-in. The time allocated for this task includes designing the test, conducting the test, and analyzing the results.

9.2.4 Phase II Reporting
Appendix F

Main Statement of Work for the Desert Peak EGS Program

Introduction

The proposed EGS work program focuses on solving a common problem in the development of geothermal projects: improving the productivity or injectivity of wells that encounter sub-commercial permeability but have been successfully completed in lithologies and stress settings known to be favorable for the natural development of hydrothermal circulation systems. These wells are attractive for financial reasons and for providing a test setting for developing and/or enhancing hydraulic connections into and within existing hydrothermal systems. Located in developed portions of geothermal fields, successfully stimulated EGS wells can mine additional heat and enable more generation from an existing power plant. The proposed work is predicated on this basis.

Initial EGS field activities within the Desert Peak area have focused on developing an area of low permeability beneath the eastern portion of the Desert Peak thermal anomaly. In the context of a Phase I feasibility assessment, a significant geotechnical effort has been made to characterize the subsurface geology in the area around well DP23-1, a non-commercial “well of opportunity” located on the eastern margin of a conventional 15 MW hydrothermal development. Following analyses aimed at characterizing the rocks and the stress field at Desert Peak, the deeper portion of a Cretaceous granodiorite was selected as a target for hydraulic stimulation. To leave only the lower portion of the granodiorite open to the well, a re-completion program was begun to install and cement a flush-joint casing down to about 7,700 feet. The plan included collecting and analyzing cores from TD, and conducting a mini-frac of the targeted interval to assist in designing a hydraulic stimulation to be undertaken in Phase II of the project. The mechanical condition in well DP23-1 resulted in a failed effort to run and cement the new casing string, and the project was suspended prior to initiation of Phase II stimulation activities.

The work undertaken to understand the rock properties and the stress regime can be fully leveraged in undertaking EGS stimulations for other Desert Peak wells.

A micro-seismic monitoring network installed prior to the attempted re-completion of well DP23-1 continues to operate. This network of surface sensors surrounds the operating hydrothermal portion of the field, where an “in-field” well (DP27-15) is an attractive target for applying EGS technology. A petrologic/mineralogic re-examination of cuttings completed as part of the initial project revealed attractive lithologic targets for stimulation in this well, some of which were also evaluated using cores from well TCH35-13, a slim hole on the eastern side of the field. Recent work to prepare and characterize well DP27-15 for stimulation has included minor well work to install a production master valve, running a suite of pressure and temperature logs, and running sonic, gamma ray and density logs to define rock properties in the open hole. These recent logging programs are included in the attached budget table as Tasks A and B. A
recent attempt to run the USGS/Sandia high-temperature borehole televiewer to evaluate the stress field and the natural fracture population was unsuccessful due to software problems in the logging unit. This work will be repeated soon; USGS, Sandia and the tool manufacturer are working actively to resolve the problems. In addition to re-running the televiewer, the next steps in the project will include stratigraphic correlation through the production wellfield and upgrading the seismic network with downhole sensors.

For reference, well locations are shown in Figure 1.

**Phase I Work Plan**

1. **Expanding the micro-seismic monitoring network.** In November 2006, seismologists from Lawrence Berkeley National Laboratory installed 9 surface seismic monitoring stations around the field. Sub-surface monitoring (as close in depth to the target zone for stimulation as possible) is preferable because of improved signal quality, which results in improved accuracy in seismic event location. However, most geophones cannot be deployed long-term in geothermal wells because of the high temperature. LBNL has a high-temperature seismic monitoring tool that can be deployed for long periods at the temperatures that prevail in or near the Desert Peak EGS reservoir zone; this tool will be deployed in an idle, deep well. Shallow downhole deployment of more conventional seismic monitoring equipment will also be initiated at levels where temperatures are lower. In these cases, monitoring will occur at depths where competent formations occur beneath the sedimentary cover (Tertiary basalt is typically found at 200-300 feet below the surface in the Desert Peak area). To facilitate seismic monitoring, Ormat is making available certain conveniently located exploratory holes (the “ST” or stratigraphic test holes) that surround the DP27-15 well. Most of these are completed with 2-7/8-inch tubing hung inside 7-inch casing. Since it is preferable to couple the seismic monitoring tool to the casing for better contact with the earth, the tubing strings will be removed in the selected wells prior to installing the geophones. This task will be undertaken as soon as possible to facilitate collection of background microseismic data, enabling the development of improved velocity models, which will also improve the accuracy of event location. With support from Ormat, Ernie Majer of LBNL will undertake this task.

2. **Petrological analysis of wells DP43-21, DP74-21 and DP77-21.** Petrology and hydrothermal alteration mineralogy have already been evaluated in the target well (DP27-15; see Figure 2). While this work has suggested appropriate lithologies for chemical and hydraulic stimulation in this well, there remains significant uncertainty about the stratigraphy and geologic structure in this part of the Desert Peak field. To better determine the extent and orientation of target formations, as well as how the secondary mineralization changes between commercially productive wells (like DP74-21 and DP77-21) and sub-commercial wells like DP27-15 and DP43-21, thin sections and XRD analyses will be
performed on drill cuttings from the three wells not yet analyzed. This work will be undertaken by Susan Lutz of TerraTek, who has significant experience with the stratigraphy in Desert Peak and other nearby geothermal areas such as Dixie Valley. Ms. Lutz will extend her previous work on DP23-1 and DP27-15 to the three wells noted above. She will also re-evaluate the geologic logs of older wells to enable stratigraphic correlations to be improved across the entire Desert Peak field. The analyses of cuttings from wells DP23-1 and DP27-15 enabled improved understanding of the lithologies and stratigraphy of the area, and this task will continue to improve the basic geologic elements of the Desert Peak conceptual model. Particular attention will be paid to characterizing the target pre-Tertiary 2 (pT2) formations around well DP27-15 and in nearby productive areas of the field.

Joe Moore of EGI will also contribute to this effort by examining the cuttings to locate fracture zones, determine the sequence of mineral fillings and relative ages of fractures. This will supplement the petrologic analysis described above, and the petrologists will collaborate on the development of the overall geologic model of the Desert Peak area.

3. Analysis of televiewer data and geophysical logs; development of stress field model. As soon as possible, the USGS/Sandia borehole televiewer will be run in well DP27-15. The televiewer data and that from the Schulmberger logs run earlier this year will be analyzed by Nick Davatze and Stephen Hickman (USGS) to determine the stress field orientation (by evaluating wellbore failures such as breakouts and drilling-induced tensile cracks), characterize the natural fracture population (particularly in attractive lithologies near the bottom of the well) and develop the stress model to guide EGS developments at Desert Peak. Some rock strength data are already available to contribute to this effort since the most promising units observed in well DP27-15 are same as those previously evaluated using core samples from TCH35-13. Additional rock properties data will be provided by tests of new cores collected at total depth (TD) in well DP27-15 (see below).

4. Re-completion of well DP27-15. Figure 2 shows the completion, temperature profile, and results of petrologic analyses in well DP27-15. This well is completed with a 13-3/8-inch production casing at approximately 3,000 feet, with a 12-1/4-inch open hole to total depth (5,810 feet). The casing shoe is located in a hydrothermally altered tuff near the base of the Tertiary section. In other Desert Peak wells, permeable zones are found at this stratigraphic horizon or in greenstones, which are sometimes found in productive wells just beneath the base of the Tertiary, at the top of basement. The greenstone unit is absent in well DP27-15; instead, like well DP23-1, there is a series of fine-grained Mesozoic marine sediments (pT1) immediately beneath the Tertiary section. On Figure 2, these are shown by the light blue formations below a depth of 3,300 feet. Owing to their relative softness and their clay content, none of the lithologies within this interval are favorable candidates for hydraulic stimulation.
Below these units is the older pre-Tertiary sequence (pT2) which includes several intrusive units that appear to be suitable for both chemical and hydraulic stimulation. This sequence (the pink formations near the bottom of the well in Figure 2) includes a phyllite unit, which is known to be mechanically unstable. Therefore, well DP27-15 will be re-completed so that only the deepest lithologies (the hornfels and the hornblende diabase) are open for later stimulation. As noted above, cores from the same pT2 sequence (from the temperature core hole TCH35-13) were evaluated in terms of their petrology, veining and mechanical properties during the previous phase of the Desert Peak EGS project; similar evaluations will be undertaken on new cores collected at TD from well DP27-15.

A suitable string of 9-5/8-inch casing is available from the Coso project; we understand that this can be provided for use in the re-completion of well DP27-15. A drilling rig will be mobilized to the site to collect a single core at the bottom of the well and run and cement the liner to a depth of ~5,350 feet (about 50 feet below the bottom of the phyllite). The core will be evaluated in terms of its lithology, mineralogy, fracturing, and mechanical properties. Because (unlike well DP23-1, which was drilled in the 1970s) well DP27-15 was recently drilled and is therefore in good mechanical condition, installing a new casing string is a low-risk operation.

Because of its proximity to existing injection wells (wells DP21-1 and DP22-22; see Figure 1) and injection pipelines, a temporary pipeline can be constructed to enable part of the injection flow to be diverted to the well DP27-15 pad to provide drilling fluids and water for the mini-frac and injection/tracer test (see below).

5. Mini-frac of well DP27-15. The plan for re-completion of well DP27-15 will include a mini-frac, which is a series of low-volume, high pressure injections designed to initiate tensile failure in the formation targeted for hydraulic stimulation. This mini-frac test will be conducted and analyzed by Stephen Hickman and Nick Davatzes (USGS). A mini-frac provides a critical measure of the magnitude of the least principal stress, and, together with observations of wellbore failures from the borehole televiewer log, sonic/density log data and core test data, enables the development of a complete three-dimensional stress model for this site. To assist with stimulation design, this model will be used to calculate the injection pressures needed to trigger shear failure (slip) on pre-existing fractures and faults seen in the image logs from wells DP27-15 and DP23-1.

In other geothermal wells, a mini-frac has been undertaken after setting a string of casing and drilling a few tens of feet below the shoe, leaving a short open hole interval for testing and break-down. Since more than 400 feet of open hole will remain below the shoe in well DP27-15 after re-completion, we will temporarily plug the well back before running the casing, leaving a short interval
below the casing shoe for the mini-frac. This technique was developed for the planned re-completion and mini-frac of the DP23-1 well and will be applied here:

a) after coring at TD, fill the open hole with sand to about 100 feet below the casing shoe
b) place a ~60-foot cement plug on top of the sand to create a good seal
c) place another ~40 feet of sand on top of the cement plug
d) run and cement the casing (landing the casing on top of the upper sand plug);
e) drill out the cement to the new casing shoe
f) circulate out the upper sand plug
g) using the cementing truck that will already be on-site (having just cemented the casing), conduct the mini-frac in the interval just below the shoe (above the cement plug)
h) drill out the cement plug, reverse circulate out the sand below the plug to TD, leaving the well available for stimulation.

6. **Pre-stimulation injection test and tracer test in DP27-15.** After re-completion, a step-rate injection test will be conducted in well DP27-15 to derive pre-stimulation injectivity and estimate critical hydraulic parameters (transmissivity, storage and wellbore “skin factor”). During the first period of injection, detailed PTS (pressure-temperature-spinner) logging will be conducted to identify permeable zones in the target interval, and a tracer will be injected to characterize the pre-stimulation hydraulic connection to the existing production wells. After the PTS logging run is finished, the tool will be “parked” at a suitable depth for pressure monitoring during the duration of the test. We will inject at 3 or 4 different rates, each injection rate step long enough to obtain stabilized downhole pressures. GeothermEx and Ormat will conduct the test.

A tracer test will be carried out as part of the injection test program. The injection tests will be run long enough to disperse the tracer into the reservoir, where convective forces will transport the tracer to surrounding production wells. These will be sampled and analyzed to characterize the pre-stimulation hydraulic connectivity between the injection well (DP27-15) and the production wells in the field. The tracer testing will be undertaken by Peter Rose of EGI.

7. **Detailed evaluation of target formation in core samples.** As discussed above, well TCH35-13 encountered the same formations that are targeted for stimulation in well DP27-15, and core samples are available. A new core will be collected from TD in well DP27-15. A detailed examination of the core is warranted because of the new focus on the pT2 formations; previously, we had considered another rock unit (a massive Cretaceous granodiorite, from which no cores were available) for stimulation. In comparison to the Cretaceous granodiorite considered in well DP23-1, the pT2 unit is older and far more fractured and veined. The vein fillings and fracturing relationships will be evaluated by Joe Moore of EGI, who will locate and identify fracture zones, determine fracture
orientations for comparison with wellbore image log data, assess the mode of fracturing, determine the mineralogy and sequence of mineral fillings, determine the relative ages of fractures, and assist with the development of the overall geologic model.

This task will also include laboratory tests of mineral dissolution. EGI has a high-temperature flow reactor that can be used to evaluate the reactions between target reservoir rocks and various acids, bases and/or chelating agents. Focusing on the pT2 unit, we will use core and cuttings from well DP27-15 and core material from well TCH35-13 in these tests, evaluating how the rock matrix and vein fillings would dissolve under various pressure, temperature and chemical conditions. Chemical stimulation at the Soultz EGS project has recently been used to enhance permeability in near-wellbore formations, resulting in significant improvements in well injectivity and productivity.

Dr. Ahmad Ghassemi (Texas A&M University) has the background and facilities to evaluate the mechanical properties of core samples of the target EGS rocks; these properties are necessary for designing stimulation programs and understanding the response of the reservoir rock to poro-elastic and thermo-elastic processes driven by water injection and extraction. In particular, Dr. Ghassemi will measure:

- Elastic modulus and Poisson’s ration
- Biot’s effective stress coefficient
- Skempton’s pore pressure coefficient
- Thermal expansion coefficient
- Porosity and permeability

These analyses will be undertaken under various pressure conditions. Then, the variation of rock properties with temperature will be studied. If feasible, Dr. Ghassemi will also characterize the fracture systems from one or more cores using CT scanning.

In addition to cores from the reservoir, the experimental program would involve a suite of well-known and well-characterized rocks from other sources (e.g., Charcoal Granite, Westerly Granite and Berea Sandstone). Testing of these “standard” rocks provides a basis for calibrating methodologies and testing procedures, and understanding the functional relationship(s) between the rock properties, pressure, and temperature. Furthermore, these tests would yield a data base of rock properties important to future EGS development based on establishing a range of values for the rock types of interest, and developing relationships between rock mineral composition and texture (grain size, arrangement, grain contact, etc.) and properties of interest.

The first series of tests would be conducted using the well-known and well-characterized rocks discussed above, followed by tests on Desert Peak rocks.
The second phase tests serve to establish additional data and correlations between rock properties, volume fractions and thermodynamic properties of stress, pore pressure, and temperature. These experiments will be conducted in Texas A&M University’s Rock Mechanics Laboratories in the Petroleum Engineering Department and the Center for Tectonophysics.

8. Development of structural model of the Desert Peak field. This work, which will be undertaken by Nick Davates and Stephen Hickman (USGS) with support from Ormat and GeothermEx, will be developed based on the stratigraphic work (Task 2) and well log analyses (Task 3) described above and field investigations of the Rhyolite Ridge Fault Zone. Specific attention will be paid to the extent and geometry of the target pT2 formations, and adjacent formations that are offset along fault zones. The evaluation will utilize published maps (e.g., Faulds et al., 2004; Oppliger et al., 2004; Benoit et al., 1982); stress field data from the image log data collected in wells DP27-15 and DP23-1; geophysical log data from older Desert Peak wells; and a detailed study of the surface trace of the Rhyolite Ridge Fault Zone, which appears to be a locus of commercial permeability at Desert Peak. A vein-filled fault zone unearthed when the drilling sump was excavated on the DP27-15 well pad will be mapped and evaluated. As shown in Figure 1, well DP27-15 is located astride the surface trace of this fault zone.

9. Tracer study of existing injection wells. Wells DP21-2 and DP22-22 are currently used for injection. Tracer tests will be initiated in each of these wells (using a different tracer in each) to characterize their hydraulic connection to the production wells. These tracer tests (and that undertaken in well DP27-15) will provide important data for understanding the permeability distribution and fluid flow paths in the reservoir, which in turn assist with calibrating the numerical model of the field (see below). The tracer testing will be undertaken by Peter Rose of EGI with support from Ormat.

10. Numerical reservoir simulation. Because this project will change the permeability structure at Desert Peak, a numerical reservoir model will be developed to optimize the use of well DP27-15 and the overall production/injection scheme. The model will be developed with significant detail in areas of interaction between the EGS well (DP27-15) and the existing production and injection wells. Grid block dimensions will be extensively refined within the production and injection area, with consideration of the stratigraphic and structural analyses described above, the known temperature distribution, and the operational needs of the existing power development. The modeling will be undertaken in the three standard stages:

a) Initial-state modeling, in which the pre-exploitation state of the reservoir is reproduced by the simulator, providing the first stage of model calibration;

b) History matching, in which the field’s response to historical production and injection is reproduced by the model, providing the second stage of
model calibration (more than 20 years of production history and the tracer tests discussed above are included among the data to be matched); and

c) Optimizing future reservoir behavior by evaluating various future production and injection scenarios, and forecasting the impact of the EGS project on current operations.

This modeling provides a mechanism for evaluating how the reservoir will behave over the long term in both the pre- and post-stimulation states. This task will be undertaken by GeothermEx with support from Ormat.

11. **Develop stimulation plan and cost estimate.** The results of the analyses described above will be evaluated in an integrated manner to design the stimulation program. At this time, we feel it is likely that the program will consist of a chemical stimulation to enhance near-wellbore permeability, followed by a hydraulic stimulation to connect into the fault and fracture zone that is the locus of production in the Desert Peak production wells. The order of these operations may be reversed depending on the results of the tasks and analyses yet to be completed. Chemical stimulation will be undertaken if one or more the following conditions prevail:

   - d) cores and cuttings show extensive carbonate and/or silicate mineral veining, and tests in the high-temperature reactor yield positive results for mineral dissolution at Desert Peak temperature and pressure conditions
   - e) the transmissivity of the un-stimulated formation is low
   - f) the well has a significant positive “skin factor” indicating near-wellbore damage.

In designing the stimulation, we will build on previous DOE-supported tests and analyses of various chelating agents that are useful in both carbonate and silicate vein deposits. This will use the results of new tests conducted in EGI’s high-temperature reactor as described above in Task 7.

Since an integrated approach is needed for the stimulation, the entire team (Ormat, GeothermEx, EGI, USGS) will develop the stimulation plans together, and obtain the requisite cost estimates for implementing those plans.

12. **Phase I Reporting.** The team will prepare a summary report on all activities completed during Phase I. We will report the results to EGS workshops and meetings, and will publish the results in the GRC Transactions and/or Stanford Workshop Proceedings.

**Phase II Work Plan**
1. **Stimulation procurement.** Firm quotes will be obtained from all vendors for the equipment and services needed to carry out the stimulation. This will include frac pump rentals, improving the water delivery system, all chemicals needed, downhole TPS logging and pressure monitoring services, seismic monitoring and other monitoring methods that may be considered (e.g., ground tilt, INSAR image analysis, active electromagnetic surveys, etc.). A timeline will be developed based on Ormat’s operational requirements and an analysis of the availability of all needed services and equipment.

2. **Stimulation of well DP27-15.** All needed equipment and personnel will be mobilized to the site. The hydraulic and/or chemical stimulations will be undertaken while conducting downhole pressure monitoring and real-time micro-seismic data collection and processing to monitor the evolution of the stimulation and adjust procedures as needed. An injection test will be conducted at the end of the stimulation to establish post-stimulation injectivity and hydraulic parameters (transmissivity, storage, wellbore “skin factor” and the radius of the stimulated zone). Detailed PTS logs will be run during the post-stimulation injection test to identify zones accepting injection fluid for comparison with pre-stimulation profiles.

3. **Stimulation analysis and design of circulation test.** The data collected during the stimulation will be analyzed to identify and characterize seismically and hydraulically active areas, and the configuration of the circulation test will be determined. All parties (Ormat, GeothermEx, LBNL, EGI, USGS) will participate in this task.

4. **Post-stimulation circulation, interference and tracer test.** A test will be conducted over several months to evaluate the changes that have occurred as a result of stimulation. During this test, the stimulated well (DP27-15) may be used as an injection well, a production well, or both. The tracer test undertaken before stimulation will be repeated to characterize the new pathways between production and injection wells. Samples of the circulating fluids will be collected and analyzed. The test will include downhole and/or wellhead pressure monitoring to enable the new hydraulic characteristics of the system to be determined. Pressure transient data will be collected during the test and after shut-in. The time allocated for this task includes designing the test, conducting the test, and analyzing the results.

5. **Re-calibrate numerical model and update forecasts of reservoir performance.** Using the data collected during the circulation test, the numerical model of the Desert Peak reservoir will be re-calibrated. New simulations of reservoir performance will be made under a variety of operating scenarios to forecast the long-term benefit of the stimulation of well DP27-15. Comparisons will be made between model-predicted and actual performance of the EGS system.
6. **Phase II reporting.** The team will prepare a summary report on all activities completed during Phase II. We will report the results to EGS workshops and meetings, and will publish the results in the GRC Transactions and/or Stanford Workshop Proceedings.
Appendix G

Statement of Work and Budget for the USGS Portion of the Desert Peak EGS Project, FY 2008

All figures gross, including USGS Overhead (40.2074% of Net)

A) BHTV log acquisition and fracture/stress orientation analysis – completed by end of Oct 2007

$10 K Equipment, transportation and per diem costs for log acquisition
$8 K Tool insurance
$30 K USGS salaries (Davatzes, Hickman and Svitek)

Subtotal: $48 K

B) Planning and supervision of minifrac; analysis of existing density/sonic/gamma logs and rock mechanics tests for in-situ rock strength; creation of integrated stress and geomechanical model. Includes participation in stimulation planning (does not include contracts for commercial pump truck and downhole pressure recording, estimated at c.a. $50 K) – stimulation planning completed by end of May 2008

$2 K Travel and per diem costs for conducting minifrac test (Hickman and Davatzes)
$30K USGS/Temple University salaries (Hickman and Davatzes)

Subtotal: $32 K

C) Creation of comprehensive structural model

$40 K USGS/Temple University salaries (currently slotted for the USGS, but could split this between USGS and Temple as needed)

Total: $120 K (Gross)
Progress Report for Year Ending December 31, 2009:
Creation of an Enhanced Geothermal System through Hydraulic and Thermal Stimulation

DE-FC07-01ID14186

Peter Rose\textsuperscript{1}, Principal Investigator; Steve Hickman\textsuperscript{2}, Co-Principal Investigator; Nick Davatzes\textsuperscript{3}, Co-Principal Investigator, Kevin Leecaster\textsuperscript{1}, Tianfu Xu\textsuperscript{4}, and Karsten Pruess\textsuperscript{4}

\textsuperscript{1}EGI, University of Utah
\textsuperscript{2}U.S. Geological Survey
\textsuperscript{3}Temple University
\textsuperscript{4}Earth Sciences Division, Lawrence Berkeley National Laboratory
10.0 Original Program Objectives

The previous objective of this cooperative agreement was to increase the injection rate into Coso well 46A-19RD from less than 10 gpm to 500 gpm at a wellhead pressure of less than 100 psi.

11.0 Modification of Objectives

The new program objectives are to support development of an Engineered Geothermal System on the margins of the Desert Peak, Nevada geothermal field. See page 64 for a statement of work for EGI’s component of the program, including a subcontract to the USGS.

12.0 Chemical Stimulation of the Near-Wellbore Formation (Rose, Leecaster, Xu and Pruess)

12.1 Objective and Approach

Removal of calcite scaling from wellbores is commonly accomplished by injecting strong mineral acid (such as HCl). Strong acids tend to enter the formation via the first fluid entry zone, dissolving first-contacted minerals aggressively while leaving much of the rest of the wellbore untreated.

An alternative to the mineral acid treatment is the use of chelating agents such as ethylenediaminetetraacetic acid (EDTA) or nitrilotriacetic acid (NTA). Such agents have the ability to chelate (or bind) metals such as calcium. Through the process of chelation, calcium ions are solvated by the chelating agent, driving calcite dissolution. The kinetics of calcite dissolution using chelating agents is not as fast as that using strong mineral acids. The lower dissolution rate allows the chelating agent to take a more balanced path through the formation and to more evenly dissolve calcite in all available fractures.

The objective of this task is to demonstrate through laboratory experiments and through numerical modeling the dissolution of silica, silicate, and calcite minerals in the presence of a chelating agent (NTA) at high temperature and pH. Results indicate that the injection of a high-pH chelating solution results in dissolution of both calcite and plagioclase minerals, and avoids precipitation of calcite at high temperature conditions. Consequently reservoir porosity and permeability can be enhanced especially near the injection well.

12.2 Accomplishments

Nothing to report this quarter.

13.0 Tracer Testing of DP Injection Wells 21-2 and 22-22 (Rose and Leecaster)

13.1 Objective

The objective of this task was to determine through tracer testing the flow patterns of fluids injected at the two injectors 21-2 and 22-22 within the Desert Peak geothermal field in
anticipation of the stimulation of the EGS target well 27-15. With a knowledge of the background flow patterns, it will be possible to better evaluate the results of the 27-15 stimulation.

13.2 Accomplishments

13.2.1 Tracer Testing of Injection Wells 22-22 and 21-2

Tracer testing completed. Nothing to report on this task this quarter.

14.0 Borehole Log Analysis, Fractures, Stress and Fluid Flow Prior to Stimulation of Well 27-15 (Davatzes and Hickman)

Nothing to report this quarter. See the March 2009 progress report for the most recent results.
Progress Report for Year Ending December 31, 2010:

Creation of an Enhanced Geothermal System through Hydraulic and Thermal Stimulation

DE-FC07-01ID14186

Peter Rose¹, Principal Investigator; Steve Hickman², Co-Principal Investigator; Nick Davatzes³, Co-Principal Investigator, Kevin Leecaster¹, Tianfu Xu⁴, and Karsten Pruess⁴

¹EGI, University of Utah
²U.S. Geological Survey
³Temple University
⁴Earth Sciences Division, Lawrence Berkeley National Laboratory
15.0 Original Program Objectives

The previous objective of this cooperative agreement was to increase the injection rate into Coso well 46A-19RD from less than 10 gpm to 500 gpm at a wellhead pressure of less than 100 psi.

16.0 Modification of Objectives

The new program objectives are to support development of an Engineered Geothermal System on the margins of the Desert Peak, Nevada geothermal field. See page 64 for a statement of work for EGI’s component of the program, including a subcontract to the USGS.

17.0 Chemical Stimulation of the Near-Wellbore Formation (Rose, Leecaster, Xu and Pruess)

17.1 Objective and Approach

Removal of calcite scaling from wellbores is commonly accomplished by injecting strong mineral acid (such as HCl). Strong acids tend to enter the formation via the first fluid entry zone, dissolving first-contacted minerals aggressively while leaving much of the rest of the wellbore untreated.

An alternative to the mineral acid treatment is the use of chelating agents such as ethylenediaminetetraacetic acid (EDTA) or nitrilotriacetic acid (NTA). Such agents have the ability to chelate (or bind) metals such as calcium. Through the process of chelation, calcium ions are solvated by the chelating agent, driving calcite dissolution. The kinetics of calcite dissolution using chelating agents is not as fast as that using strong mineral acids. The lower dissolution rate allows the chelating agent to take a more balanced path through the formation and to more evenly dissolve calcite in all available fractures.

The objective of this task is to demonstrate through laboratory experiments and through numerical modeling the dissolution of silica, silicate, and calcite minerals in the presence of a chelating agent (NTA) at high temperature and pH. Results indicate that the injection of a high-pH chelating solution results in dissolution of both calcite and plagioclase minerals, and avoids precipitation of calcite at high temperature conditions. Consequently reservoir porosity and permeability can be enhanced especially near the injection well.

17.2 Accomplishments

Task completed.

18.0 Tracer Testing of DP Injection Wells 21-2 and 22-22 (Rose and Leecaster)

18.1 Objective

The objective of this task was to determine through tracer testing the flow patterns of fluids injected at the two injectors 21-2 and 22-22 within the Desert Peak geothermal field in
anticipation of the stimulation of the EGS target well 27-15. With a knowledge of the background flow patterns, it will be possible to better evaluate the results of the 27-15 stimulation.

18.2 Accomplishments

18.2.1 Tracer Testing of Injection Wells 22-22 and 21-2

Tracer testing completed.

19.0 Borehole Log Analysis, Fractures, Stress and Fluid Flow Prior to Stimulation of Well 27-15 (Davatzes and Hickman)

See the March 2009 progress report for the most recent results.
Progress Report for Year Ending December 31, 2011:

Creation of an Enhanced Geothermal System through Hydraulic and Thermal Stimulation

DE-FC07-01ID14186

Peter Rose¹, Principal Investigator; Steve Hickman², Co-Principal Investigator; Nick Davatzes³, Co-Principal Investigator, Kevin Leecaster¹, Tianfu Xu⁴, and Karsten Pruess⁴

¹EGI, University of Utah
²U.S. Geological Survey
³Temple University
⁴Earth Sciences Division, Lawrence Berkeley National Laboratory
20.0 Original Program Objectives

The previous objective of this cooperative agreement was to increase the injection rate into Coso well 46A-19RD from less than 10 gpm to 500 gpm at a wellhead pressure of less than 100 psi.

21.0 Modification of Objectives

The new program objectives are to support development of an Engineered Geothermal System on the margins of the Desert Peak, Nevada geothermal field. See page 64 for a statement of work for EGI’s component of the program, including a subcontract to the USGS.

22.0 Chemical Stimulation of the Near-Wellbore Formation (Rose, Leecaster, Xu and Pruess)

22.1 Objective and Approach

Removal of calcite scaling from wellbores is commonly accomplished by injecting strong mineral acid (such as HCl). Strong acids tend to enter the formation via the first fluid entry zone, dissolving first-contacted minerals aggressively while leaving much of the rest of the wellbore untreated.

An alternative to the mineral acid treatment is the use of chelating agents such as ethylenediaminetetraacetic acid (EDTA) or nitrilotriacetic acid (NTA). Such agents have the ability to chelate (or bind) metals such as calcium. Through the process of chelation, calcium ions are solvated by the chelating agent, driving calcite dissolution. The kinetics of calcite dissolution using chelating agents is not as fast as that using strong mineral acids. The lower dissolution rate allows the chelating agent to take a more balanced path through the formation and to more evenly dissolve calcite in all available fractures.

The objective of this task is to demonstrate through laboratory experiments and through numerical modeling the dissolution of silica, silicate, and calcite minerals in the presence of a chelating agent (NTA) at high temperature and pH. Results indicate that the injection of a high-pH chelating solution results in dissolution of both calcite and plagioclase minerals, and avoids precipitation of calcite at high temperature conditions. Consequently reservoir porosity and permeability can be enhanced especially near the injection well.

22.2 Accomplishments

Task complete.

23.0 Tracer Testing of DP Injection Wells 21-2 and 22-22 (Rose and Leecaster)

23.1 Objective

The objective of this task was to determine through tracer testing the flow patterns of fluids injected at the two injectors 21-2 and 22-22 within the Desert Peak geothermal field in
anticipation of the stimulation of the EGS target well 27-15. With a knowledge of the background flow patterns, it will be possible to better evaluate the results of the 27-15 stimulation.

23.2 Accomplishments

23.2.1 Tracer Testing of Injection Wells 22-22 and 21-2

Tracer testing was continued with the purpose of measuring the return of fluorescein, Safranin T and 1,6-nds from the recently stimulated DP well 27-15. Shown below in Figure 1 is a plot of the returns of the four tracers sulfophthalic anhydride (SPA), 1,6-naphthalene disulfonate (1,6-nds), fluorescein, and Safranin T to DP well 74-21.

![Figure 1. Returns of tracers from stimulated DP well 27-15 to DP production well 74-21.](image)

24.0 Borehole Log Analysis, Fractures, Stress and Fluid Flow Prior to Stimulation of Well 27-15 (Davatzes and Hickman)

See the March 2009 progress report for the most recent results.
Progress Report for Year Ending June 30, 2012:

Creation of an Enhanced Geothermal System through Hydraulic and Thermal Stimulation

DE-FC07-01ID14186

Peter Rose¹, Principal Investigator; Steve Hickman², Co-Principal Investigator; Nick Davatzes³, Co-Principal Investigator, Kevin Leecaster¹, Tianfu Xu⁴, and Karsten Pruess⁴

¹EGI, University of Utah
²U.S. Geological Survey
³Temple University
⁴Earth Sciences Division, Lawrence Berkeley National Laboratory
25.0 Original Program Objectives

The previous objective of this cooperative agreement was to increase the injection rate into Coso well 46A-19RD from less than 10 gpm to 500 gpm at a wellhead pressure of less than 100 psi.

26.0 Modification of Objectives

The new program objectives are to support development of an Engineered Geothermal System on the margins of the Desert Peak, Nevada geothermal field. See page 64 for a statement of work for EGI’s component of the program, including a subcontract to the USGS.

27.0 Chemical Stimulation of the Near-Wellbore Formation (Rose, Leecaster, Xu and Pruess)

27.1 Objective and Approach

Removal of calcite scaling from wellbores is commonly accomplished by injecting strong mineral acid (such as HCl). Strong acids tend to enter the formation via the first fluid entry zone, dissolving first-contacted minerals aggressively while leaving much of the rest of the wellbore untreated.

An alternative to the mineral acid treatment is the use of chelating agents such as ethylenediaminetetraacetic acid (EDTA) or nitrilotriacetic acid (NTA). Such agents have the ability to chelate (or bind) metals such as calcium. Through the process of chelation, calcium ions are solvated by the chelating agent, driving calcite dissolution. The kinetics of calcite dissolution using chelating agents is not as fast as that using strong mineral acids. The lower dissolution rate allows the chelating agent to take a more balanced path through the formation and to more evenly dissolve calcite in all available fractures.

The objective of this task is to demonstrate through laboratory experiments and through numerical modeling the dissolution of silica, silicate, and calcite minerals in the presence of a chelating agent (NTA) at high temperature and pH. Results indicate that the injection of a high-pH chelating solution results in dissolution of both calcite and plagioclase minerals, and avoids precipitation of calcite at high temperature conditions. Consequently reservoir porosity and permeability can be enhanced especially near the injection well.

27.2 Accomplishments

Task complete.

28.0 Tracer Testing of DP Injection Wells 21-2 and 22-22 (Rose and Leecaster)

28.1 Objective

The objective of this task was to determine through tracer testing the flow patterns of fluids injected at the two injectors 21-2 and 22-22 within the Desert Peak geothermal field in
anticipation of the stimulation of the EGS target well 27-15. With a knowledge of the background flow patterns, it will be possible to better evaluate the results of the 27-15 stimulation.

28.2 Accomplishments

28.2.1 Tracer Testing of Injection Wells 22-22 and 21-2

Tracer testing was continued with the purpose of measuring the return of fluorescein, Safranin T and 1,6-nds from the recently stimulated DP well 27-15. Shown below in Figure 1 is a plot of the returns of the four tracers sulfophthalic anhydride (SPA), 1,6-naphthalene disulfonate (1,6-nds), fluorescein, and Safranin T to DP well 74-21.

![Figure 1. Returns of tracers from stimulated DP well 27-15 to DP production well 74-21.](image_url)

29.0 Borehole Log Analysis, Fractures, Stress and Fluid Flow Prior to Stimulation of Well 27-15 (Davatzes and Hickman)

See the March 2009 progress report for the most recent results.