U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy

GEOTHERMAL TECHNOLOGIES PROGRAM

Reservoir Engineering 1976 – 2006

A History of Geothermal Energy Research and Development in the United States

Cover Photo Credit

Fenton Hill, New Mexico Hot Dry Rock program site. (Courtesy: Donald W. Brown)

This history of the U.S. Department of Energy's Geothermal Program is dedicated to the many government employees at Headquarters and at offices in the field who worked diligently for the program's success. Those men and women are too numerous to mention individually, given the history's 30-year time span. But they deserve recognition nonetheless for their professionalism and exceptional drive to make geothermal technology a viable option in solving the Nation's energy problems. Special recognition is given here to those persons who assumed the leadership role for the program and all the duties and responsibilities pertaining thereto:

- Eric Willis, 1976-77
- James Bresee, 1977-78
- Bennie Di Bona, 1979-80
- John Salisbury, 1980-81
- John "Ted" Mock, 1982-94
- Allan Jelacic, 1995-1999
- Peter Goldman, 1999-2003
- Leland "Roy" Mink, 2003-06

These leaders, along with their able staffs, are commended for a job well done. The future of geothermal energy in the United States is brighter today than ever before thanks to their tireless efforts.

Table of Contents

Preface . . . vii

Acknowledgements . . . ix

Introduction . . . 1

Accomplishments and Impacts . . . 3

Major Research Projects . . . 7

1.0 Field Case Studies . . . 9
- 1.1 The Geysers, California . . . 9
- 1.2 Cerro Prieto, Mexico . . . 16
- 1.3 Larderello, Italy . . . 18
- 1.4 Dixie Valley, Nevada . . . 19
- 1.5 Well Testing Campaigns . . . 25
- 1.6 Geothermal Reservoir Well Stimulation Program . . . 26

2.0 Hot Dry Rock . . . 33
- 2.1 The Early Days (1970–1973) . . . 35
- 2.2 Phase I Drilling and Testing (1974–1980) . . . 40
- 2.3 Phase II Drilling and Testing (1981–1995) . . . 43
- 2.4 Findings and Conclusions . . . 64

3.0 Geopressured-Geothermal Energy Program . . . 67
- 3.1 Background . . . 67
- 3.2 Wells of Opportunity . . . 70
- 3.3 Design Wells . . . 72
- 3.4 Calcium Carbonate Scaling . . . 78
- 3.5 Environmental Issues . . . 81
- 3.6 Economic Evaluation for Electrical Generation . . . 81
- 3.7 Findings and Conclusions . . . 86

4.0 Modeling of Geothermal Systems . . . 87
- 4.1 Reservoir Modeling Overview . . . 87
- 4.2 Reservoir Modeling Considerations . . . 87
- 4.3 Reservoir Modeling Techniques . . . 88
- 4.4 The TOUGH Family of Codes . . . 94
- 4.5 Wellbore Models . . . 102
- 4.6 PetraSim Graphical User Interface . . . 102

5.0 Geoscience Support Projects . . . 105
- 5.1 Tracer Development . . . 105
- 5.2 Tracer Interpretation . . . 108

6.0 Enhanced Geothermal Systems . . . 123
- 6.1 Science and Technology Research Projects . . . 126
- 6.2 Industry Field Demonstration Projects . . . 142
- 6.3 Induced Seismicity . . . 145
- 6.4 Is EGS the Future of Geothermal Energy? . . . 146

Conclusion . . . 149
Appendix A: Budget history of the federal geothermal research program, 1976 – 2006 . . . 151
Abbreviations & Acronyms . . . 157
References Organized by Major Research Project Area . . . 161
Numbered References . . . 183

List of Figures

Figure 1. A general location map of The Geysers Geothermal Field . . . 10
Figure 2. Location of seismic stations, pipelines, and injection wells at The Geysers. . . . 11
Figure 3. Historical seismicity from 1965 to October 2006 at The Geysers. . . . 12
Figure 4. Location of all seismic events in The Geysers field in October 2003, two months prior to start of injection of treated Santa Rosa wastewater. . . . 13
Figure 5. Location of all seismic events in The Geysers field in March 2004, after the start of injection of treated Santa Rosa wastewater . . . 14
Figure 6. Location of seismic events in northern California with magnitudes greater than 3.0 and less than 5.0, from January 1900 to mid May 2004 . . . 15
Figure 7. Location of Cerro Prieto geothermal field, Mexico . . . 16
Figure 8. Simplified configuration of Dixie Valley Basement . . . 20
Figure 9. The region west of Los Alamos . . . 33
Figure 10. Fenton Hill, New Mexico Hot Dry Rock program site . . . 34
Figure 11. Originally proposed concept for a Hot Dry Rock geothermal energy system . . . 35
Figure 12. Plan view of the trajectories of the Phase I boreholes: EE-1, GT-2, and the two redrilled "legs" GT-2A and GT-2B . . . 41
Figure 13. Water-loss rates during Run Segment 5 . . . 42
Figure 14. Measured variations in the production temperature during Run Segment 5 . . . 42
Figure 15. The Phase II reservoir development plan . . . 45
Figure 16. Trajectories of the completed EE-2 and EE-3 boreholes . . . 46
Figure 17. Locations of microseismic events at Fenton Hill, New Mexico . . . 47
Figure 18. The surface injection rate and pressure profiles during the 2.5 days of the Massive Hydraulic Fracturing Test in EE-2 . . . 49
Figure 19. Density plots of microearthquakes detected by downhole seismic instruments during the injection phase of the Massive Hydraulic Fracturing Test . . . 49
Figure 20. Correspondence between injection pressures and microearthquake occurrences over the course of the Initial Closed-Loop Flow Test . . . 52
Figure 21. Distributions of seismic events during the Massive Hydraulic Fracturing test and the Initial Closed-Loop Flow Test . . . 53

Figure 22. Water-loss rate vs. log (time) during the 15-MPa pressure plateaus of Experiment 2077 57

Figure 23. Injection and production flow profiles vs. the controlled variation in the production well backpressure during the last two daily cycles of the Load-Following Experiment 60

Figure 24. Tracer recovery profiles (three fluorescein and one p-TSA) during steady-state operation (1992–1993) 63

Figure 25. Location of geopressured basins in the United States 67

Figure 26. Location of wells investigated as part of the U.S. Department of Energy geopressured-geothermal research program in the Gulf Coast 69

Figure 27. Schematic illustration of the Hybrid Power System (HPS) installed and tested at Pleasant Bayou 76

Figure 28a. Schematic illustration of the surface equipment installed to process the co-produced gas and brine 77

Figure 28b. To accommodate the high brine flow rate, a block “Y” was installed on the production wellhead 77

Figure 29. The impact of increased flow rates on the rate of calcium carbonate scale deposition (B/D: barrels per day) 79

Figure 30. The amount of calcium carbonate scale removed by acid treatment shown as function of the cumulative amount of brine production 80

Figure 31. The role of the Natural State Model in reservoir evaluation and performance prediction 97

Figure 32. The natural state temperature distribution and the fluid flow patterns computed for the Krafla field 98

Figure 33. Chemical stimulation using chelating agent Nitrilotriacetate (NTA) 100

Figure 34. Results of coupled thermal-hydraulic-mechanical (THM) analysis of microearthquake (MEQ) potential associated with coldwater injection at Aidlin 11, Northwest Geysers, California 101

Figure 35. Iso-surface plot of temperatures using PetraSim 103

Figure 36. A flow-storage diagram for a four-fracture network 109

Figure 37. Tracer breakthrough curves for different fracture spacing 110

Figure 38. Process flow diagram for steam-water experiment 113

Figure 39. Interpretations of steam-water relative permeabilities using modified tortuous-channel model (MTCM): smooth-walled fracture data 114

Figure 40. The prediction of the distribution of aqueous aluminum species as a function of pH and temperature in pure water at 90°C (194°F) 120

Figure 41. Pressure-composition predictions of EOS for the CO_2-H_2O system 121

Figure 42. Enhanced Geothermal System Concept 25

Figure 43. Evolution of fracture permeability observed on the Desert Peak core DP3972.1 127
Figure 44. Surface profiles of the fracture surface (a) before and (b) after the induced flow 128
Figure 45. Calculated flow using 2-D finite difference discretization of Reynolds equation in measured aperture. . . . 128
Figure 46. Shear slip (m) in the y-direction in the absence of thermal stresses 133
Figure 47. Schematic illustrating logistics of ultra remote referencing applied to magnetotelluric (MT) data collection at the Coso geothermal field. . . . 134
Figure 48. Plan view slices at depths of 150, 1,200 and 2,000 meters, showing the model parameters recovered from 3-D MT inversion 135
Figure 49. Map of Long Valley Caldera showing the proposed flow path of the Long Valley hydrothermal fluid 141

List of Tables

Table 1. Major advances in reservoir engineering resulting from the Department of Energy's geothermal research and development program, 1976 – 2006 3
Table 2. Summary of Results of Stimulation Experiments 27
Table 3. Heat-Flow Values in Intermediate-Depth Test Holes. . . . 36
Table 4. A summary of the operating conditions for Run Segment 5. . . . 43
Table 5. Operating Conditions during Two Quasi-Steady-State Periods Representing the Two Segments of the Initial Closed-Loop Flow Test. . . . 51
Table 6. Long-Term Flow Test Operating Data 62
Table 7. Summary of Pertinent Test Results for Geopressured Geothermal Test Wells of Opportunity 70
Table 8. Summary of Pertinent Test Results for Geopressured Geothermal Test Design Wells 74
Table 9. Breakeven price to produce electricity from a geopressured-geothermal resource for selected well cases and production scenarios (A, B, C, D). 84
Table 10. Development of the TOUGH codes 95
Table 11. Advantages and drawbacks of tracers used in geothermal systems 106
Table 12. Status of U.S. Department of Energy-Supported Pitzer Model Development 119

Preface

In the 1970s, the publicly available information about geothermal systems was woefully inadequate. The understanding of geothermal resources and the means for their optimum development was primitive. Much of the extant information was held in private company files. Lack of information meant only a few companies invested in exploration and resource development. Utilities did not understand the geothermal resource, especially the risks and costs of development, and they were therefore reluctant to sign long-term geothermal power purchase agreements. For the same reasons, financial institutions were wary of funding geothermal energy projects. Development of the large resource base in the United States, apart from The Geysers in California, was essentially stagnant. This was the environment in which the U.S. Government's geothermal research and development (R&D) program began.

The intent of the geothermal program was to understand geothermal resources, improve geothermal science and engineering technology, and ensure that information was publicly available to geothermal stakeholders, such as developers, utilities, financial institutions, regulators, and others necessary to spur development of a vital, progressive geothermal industry. As this report will demonstrate, the intent was achieved, to the benefit not only of geothermal energy development in the United States but also around the world.

This report is one of a series issued by the U.S. Department of Energy (the Department) to document the many and varied accomplishments stemming from the Government's sponsorship of geothermal research since 1976. The report represents a history of the major research programs and projects that have had a lasting impact on the use of geothermal energy in the United States or which promise to have an impact. We have not attempted to write the definitive history of the Geothermal Program and the $1.3 billion that were expended through 2006 on geothermal research. Rather, we have brought together the collective memories of those who participated in the program to highlight advances that the participants deem worthy of special recognition.

In particular, this report examines the work done in one key area of geothermal technology development: Reservoir Engineering. Companion reports cover work in other areas, including Drilling, Energy Conversion, and Exploration. The history focuses on the period 1976–2006, when the Department was the lead agency for geothermal technology research as mandated by the Geothermal Research, Development and Demonstration Act of 1974. The earlier, groundbreaking work by precursor agencies, such as the National Science Foundation, Atomic Energy

Commission, United States Geological Survey, and the Energy Research and Development Administration, is cited as appropriate but is by no means complete.

Those wishing to learn more about certain topics discussed herein should consult the references listed in the report. These sources give the reader access to a much larger body of literature that covers the topics in greater detail. Another useful source of information about the Department's geothermal research can be found in the Geothermal Technologies Legacy Collection (www.osti.gov/geothermal/) maintained by the Office of Science and Technology Information.

The budget history of the federal geothermal research program during the 30-year period documented here is included as Appendix A. That portion of the budget devoted to reservoir engineering is highlighted and amounts to over $480 million in actual dollars. Funding for work in reservoir engineering other than Enhanced Geothermal Systems ended in fiscal year 2006 with a decision by the Department to refocus limited funding resources on higher priority needs within the Office of Energy Efficiency and Renewable Energy. That decision did not preclude future work in this area, as the needs for geothermal technology development are assessed. This report summarizes the products and benefits of that earlier research investment.

Acknowledgements

While the many contributors to United States Department of Energy-supported geothermal reservoir engineering research and development over the years are too numerous to acknowledge by name, we wish to mention those who participated in writing this report. The primary authors were B. Mack Kennedy, Karsten Pruess, Marcelo J. Lippmann, and Ernest L. Majer of the Earth Sciences Division of Lawrence Berkeley National Laboratory; Peter E. Rose and Michael Adams of the Energy & Geosciences Institute of the University of Utah; Ann Robertson-Tait of GeothermEx Inc.; Nancy Möller and John Weare of the Department of Chemistry and Biochemistry of the University of California, San Diego; and Ted Clutter of ArtComPhoto. Donald W. Brown of Los Alamos National Laboratory wrote the historical account of the Hot Dry Rock program at Fenton Hill, New Mexico. Elizabeth C. Battocletti, Allan Jelacic, and Phillip Michael Wright served as the report's technical editors. These persons deserve credit for assembling a history of impressive accomplishment that will continue to reap benefits for many years to come. To the individuals whose efforts are not specifically identified in this report, the Department and authors offer their sincere gratitude.

Introduction

This report summarizes significant research projects performed by the U.S. Department of Energy (DOE)'s Geothermal Technologies Program[1] over the past 30 years to overcome challenges in reservoir engineering and make geothermal electricity more cost-competitive. At the onset of DOE's efforts in the 1970s, several national laboratories, universities, and contractors conducted energy conversion research. The program was initiated to develop core technologies to assist the geothermal industry in finding, operating, and managing geothermal fields, and to expand the geothermal resource base through innovative technologies for heat extraction. This report synthesizes research funded to develop and implement technologies relevant to geothermal reservoirs.

DOE-supported reservoir engineering R&D focused on:

- Technologies for the more effective operation and management of resources under production, including reservoir simulators, tracer development and interpretation, and reservoir monitoring;
- Techniques for establishing the physical and chemical properties of reservoir rocks and fluids relevant to predicting productive capacity and longevity under commercial exploitation;
- Innovative technologies for heat extraction from novel resources such as geopressured-geothermal, and hot dry rock (HDR); and
- Site-specific cooperative studies with the geothermal industry in both the United States and abroad to understand reservoir behavior in different geologic environments. Such research included theoretical analyses, modeling, laboratory experiments, and field studies related to site-specific demonstration and verification.

Accomplishments and Impacts

Table 1 summarizes the major advances resulting from DOE R&D in reservoir engineering from 1976 through 2006. They are not ranked in any particular order of importance or priority. Each of these fields has made a significant contribution to fulfillment of the DOE's goals, and each has had a major impact on worldwide geothermal development.

Accomplishments and impacts specific to each focus area are described in greater detail in the sections following the table.

Table 1. Major advances in reservoir engineering resulting from the Department of Energy's geothermal research and development program, 1976 – 2006

Technical Area	Accomplishment	Significance	Industry Measure
Field Case Studies	Collaborated with the private sector and foreign institutions to gather, analyze and interpret a very large amount of new data on high-temperature vapor- and water-dominated geothermal systems. Used these new databases to develop and test new interpretation techniques developed elsewhere in the DOE program. Published results of the work in numerous reports and technical journals, increasing the amount of geothermal data in the public domain manyfold.	Allowed testing of new surface and downhole tools under actual field conditions and calibration of computer codes against actual field data. Facilitated technical contacts between U.S. and foreign organizations.	Provided developers with information and field-tested techniques that are being used today in the design of geothermal exploration, development, and exploration activities.

Technical Area	Accomplishment	Significance	Industry Measure
Hot Dry Rock	Completed the first ever Hot Dry Rock (HDR) project at Fenton Hill, New Mexico. Developed and flow-tested two separate fully engineered HDR reservoirs between 1974 and 1995. These reservoirs are unique in being totally confined, with only very small levels of diffusional water loss (5-10 gpm) at their pressurized boundaries.	Demonstrated the generation of electricity from hot dry rock with associated microseismicity having magnitude < 1 on the Richter Scale. With considerable well repair and re-opening, the deeper reservoir could be made available for further testing. This could lead to as much as 40 MWt of power capacity with a production temperature of 200°C (392°F), equivalent to at least 6 MWe.	The information and experience from Fenton Hill has been extremely valuable in planning and conducting ongoing enhanced geothermal systems projects worldwide. Extensive testing of downhole drilling, logging and other equipment helped significantly advance technology.
Geopressured-Geothermal Energy Program	Identified and evaluated U.S. geopressured-geothermal resources. Demonstrated that high brine-flow rates can be sustained; that sanding, scaling and corrosion can be controlled; that gas production from saturated brines under pressure is viable; and that spent brine can be injected into shallower aquifers. Demonstrated the operation of a hybrid power system for conversion of thermal and chemical energy to electricity.	Geopressured-geothermal energy was determined to be a significant and viable resource. Disproved and clarified many historical perceptions that had previously limited industry's interest in developing the geopressured-geothermal resource. Observed no detrimental environmental effects attributed to well testing.	Provided scientific and engineering information to support development of geopressured-geothermal resources. Laid the foundation for today's resurgence in extracting energy from co-produced hot brines associated with oil and gas operations.

Technical Area	Accomplishment	Significance	Industry Measure
Modeling of Geothermal Systems	Developed and made available geothermal reservoir simulators capable of accepting data on well-head and downhole pressure, temperature, flow rate, injection and other parameters including their time histories, as well as reservoir geology, geochemistry, and geophysics in 3D, and making predictions going forward of such reservoir parameters as size, productivity, sustainability of production, temperature and pressure decline. This greatly advanced the ability of reservoir engineers to predict responses to such variables as changes in production, injection, temperature, etc. Used these reservoir simulators for numerous case studies, thereby substantially advancing understanding of geothermal resources and their responses to utilization. Conceptual models of volcanic-hosted geothermal systems were developed.	Freely provided advanced technology to the entire geothermal community. Laid the basis for acceptance of geothermal resources as viable energy sources by utilities and funding institutions. Provided needed properties of reservoir models to all users of DOE computer codes. Allowed improved determination of reservoir, rock, and fluid parameters in geothermal reservoirs.	DOE-developed reservoir simulators are now in use at over 300 installations in 30 countries. Utilization of geothermal resources is now much better understood by energy companies, utilities and the financial sector.

Technical Area	Accomplishment	Significance	Industry Measure
Geoscience Support Projects	Aided in the development of field, laboratory, and numerical methods of interest to the geothermal community, particularly developers. Identified and tested a suite of reactive and non-reactive chemical tracers for use in geothermal reservoirs. Developed a better understanding of fluid geochemistry and rock-fluid reactions as well as the development of appropriate computer simulation tools.	Tracers are now routinely used to monitor fluid flow, heat extraction, and other changes within reservoirs. Provided equations of state for implementation in reservoir simulators. Improved estimates of reservoir and equipment degradation due to mineral scaling. Identified possible environmental effects associated with the development of geothermal resources and measures to avoid or reduce them.	Gave developers a set of tracers that can be used to characterize reservoirs and to monitor the behavior of reservoirs, wells, and surface equipment. Furnished the geothermal industry with more accurate tools to avoid (or reduce) thermal interference between injection and production wells, and to optimize the design of assessment and management operations. Improved the ability of the developer to prevent and mitigate undesirable fluid effects.
Enhanced Geothermal Systems	Provided impetus and funding to the industry for collaborative feasibility studies to evaluate EGS as an energy source and to develop improved technologies for its use.	A significant portion of worldwide energy demand would be met by EGS if technology could be improved to allow its widespread development. Existing hydrothermal resources could potentially be extended by using EGS technology to utilize heat in low-permeability rocks on the margins of fields. EGS development could eventually allow geothermal utilization in areas where the thermal gradient is much lower than it is in known hydrothermal areas.	A new energy industry would be the result of successful EGS technology. Current geothermal power producers would be able to turn some unproductive wells into injection or production wells.

Major Research Projects

This report summarizes significant research projects performed by DOE over a period of 30 years to overcome challenges in reservoir engineering and to make geothermal electricity more cost-competitive. Research was carried out by a variety of institutions, including government laboratories, academic institutions, and private companies. A key feature in making this research program a success was collaboration with the private sector. This report discusses work done in six areas related to reservoir engineering:

1. Field Case Studies.
2. Hot Dry Rock – Fenton Hill Dedicated Test Site.
3. Geopressured-Geothermal Energy Program.
4. Modeling of Geothermal Systems.
5. Geoscience Support Projects.
6. Enhanced Geothermal Systems.

1.0 Field Case Studies

One component of the Department's reservoir engineering R&D program involved case studies of developed geothermal resources. As more geothermal fields became operational during the 1970s and 1980s, a large amount of data was acquired through collaborative research with geothermal project developers and field operators. This collaboration was based on agreements allowing DOE-funded researchers to analyze existing data sets and collect additional field data. The resulting information was used to significantly advance our understanding of geothermal reservoirs and help the geothermal industry optimize operations and reduce costs. Six of the key field case studies are summarized below.

1.1 The Geysers, California

Commercial development of The Geysers steam-dominated geothermal system in northern California (Figure 1)[2] began in 1960 with the construction of an 11-megawatt (MW) plant—the first commmercial geothermal plant in the United States. In the following decades, The Geysers became the largest producing geothermal field in the United States. Steam output and electricity generation peaked in the late 1980s, with an operating capacity of about 1,600 megawatts-electric (MWe) and an installed capacity of around 2,000 MWe. By the mid 1980s, however, reservoir pressures and steam output had begun to decline as a result of overdevelopment of the field, insufficient natural recharge (vapor-dominated systems necessarily have low natural recharge), and low rates of injection of spent geothermal fluids because the condensate from the power plants was being used in the cooling towers.[3]

From the beginning of exploration and development at The Geysers, collaboration between researchers and developers was carried out on an informal basis. A great deal was learned about the geological and geochemical characteristics of the large Geysers geothermal system. In the mid 1980s, however, when steam availability problems began to emerge, formal cooperation between developers and the Department was instituted in earnest. A series of joint projects was undertaken and a number of technical meetings were held to discuss reservoir management of vapor-dominated systems. Then, in the 1990s, large sources of injection water became available from treated wastewater on both the Lake County and Sonoma County sides of the field when surface disposal of these waters was prohibited unless they were given additional, expensive treatment. Thus, it became cost-effective to transport the wastewater to the geothermal field and dispose of it by injection. In response, DOE began collaboration with the operators of The Geysers field to further advance understanding of the field, especially under injection, and to help plan and evaluate the effects of large-scale injection on the behavior of the steam reservoir.

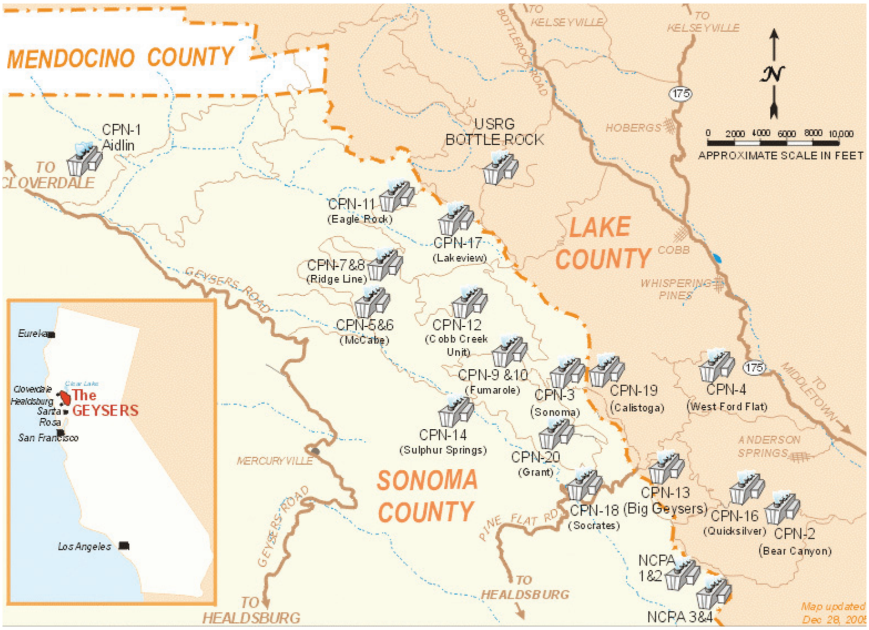


Figure 1. A general location map of The Geysers Geothermal Field
(Source: Geysers Geothermal Association)

1.1.1 Injection at The Geysers

Injection operations had been carried out at The Geysers for many years at low volumes relative to the volume of water being removed during production. Two particularly large increases in injection rates occurred when, in 1997, the Southeast Geysers Effluent Pipeline (SEGEP) began delivering treated reclaimed water and lake water from Lake County to Geysers injection wells at a rate of about 26 million liters (7 million gallons) per day through a 46.4-kilometer (28.8-mile) underground pipeline. This pipeline project was the first recycled water-to-electricity project in the world. In addition, in 2003, the Santa Rosa Reclaimed Water Geysers Recharge Project (SRGRP) began delivering about 42 million liters (11 million gallons) per day of treated wastewater from the city of Santa Rosa through a 64-kilometer (40-mile) underground pipeline to injection wells at The Geysers. Figure 2 shows the location of the SEGEP and SRGRP pipelines, the injection wells and seismic stations used to monitor the injection.[5] The Department supported the construction of both the SEGEP and the SRGRP pipelines, and has been heavily involved in seismic monitoring of the injection and production processes.

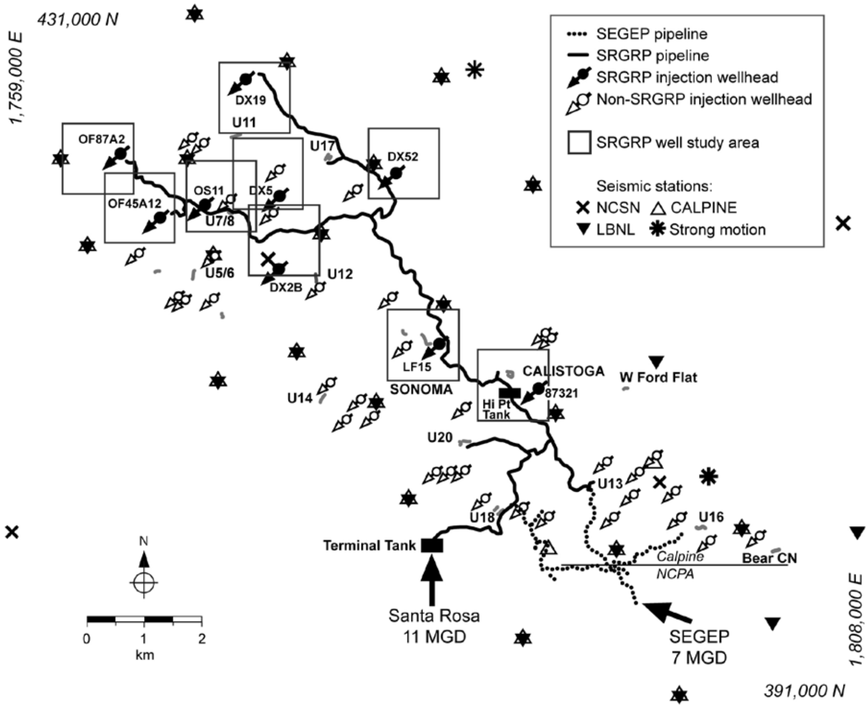


Figure 2. Location of seismic stations, pipelines, and injection wells at The Geysers.

SEGEP: South East Geysers Effluent Project; SRGRP: Santa Rosa Reclaimed Water Geyers Recharge Project; NCSN: Northern California Seismic Network of the U.S. Geological Survey (USGS); CALPINE: Calpine Corporation; LBNL: Lawrence Berkeley National Laboratory; MGD: million gallons per day (1 gallon = 3.785 litres)

1.1.2 Induced Seismicity at The Geysers

DOE was involved in the majority of the seismicity studies at The Geysers, working in cooperation with the field's developers, the U.S. Geological Survey (USGS), and the California Energy Commission.[4-15]

The region surrounding The Geysers field is located within the environment of the San Andreas transform fault system, and is therefore tectonically stressed, cut by numerous faults, and subject to a high level of natural earthquake activity.[16] Geologic mapping indicates that none of the faults within the field have been active in the last 10,000 years. The Collayomi Fault, running approximately 1.6 kilometers (0.9 miles) northeast of the field limit, is mapped as inactive. The Mayacamas Fault, about 6 kilometers (4 miles) southwest of the field limit, is the nearest active fault. On the Lake County side, the active Konocti Bay fault system is located approximately 13 kilometers (8 miles) north of the field limit.

Researchers began compiling data on microseismicity (i.e., magnitude ≤ 3.0) at The Geysers when the field was first developed in the 1960s. Pre-production baseline data sets, though incomplete, strongly suggested that little seismicity occurred in the field for at least 10 years prior to the 1960 start-up of commercial production. Seismicity increased and became more frequent as field development expanded. Earthquakes tended to cluster near the bottoms of wells, especially injection wells. The inevitable conclusion was that reservoir operations were inducing small earthquakes.[16]

Since 1980, two or three events per decade of magnitude greater than 4.0 have occurred—as well as an average of about 18 events per year of magnitude greater than 3.0. The largest earthquake recorded at The Geysers had a magnitude 4.6 and occurred in 1982. Since 1985, earthquake frequency and magnitude distributions have been more or less stable.

Injection rates in the southeast Geysers doubled beginning in late 1997 with the SEGEP. The injection-rate doubling did not lead to any significant change in the continuing rate of increase for seismic events of magnitude 1.5 and greater in the southeast (SE) Geysers area. Events of magnitude 2.5 and greater initially continued at about the pre-pipeline rate for the next four years. However, although injection decreased in the period 1997 to 2003, seismicity increased somewhat in this time period. Figure 3 shows the historical seismicity from 1965 to October 2006 at The Geysers field. Data are from the Northern California Earthquake Data Center (NCEDC). The two arrows indicate the increases in fluid injection in 1997 and 2002.[16-17] Seismicity observed in this area from 2000 to 2006 did not appear to be directly related to the injection of wastewater from these pipeline operations.

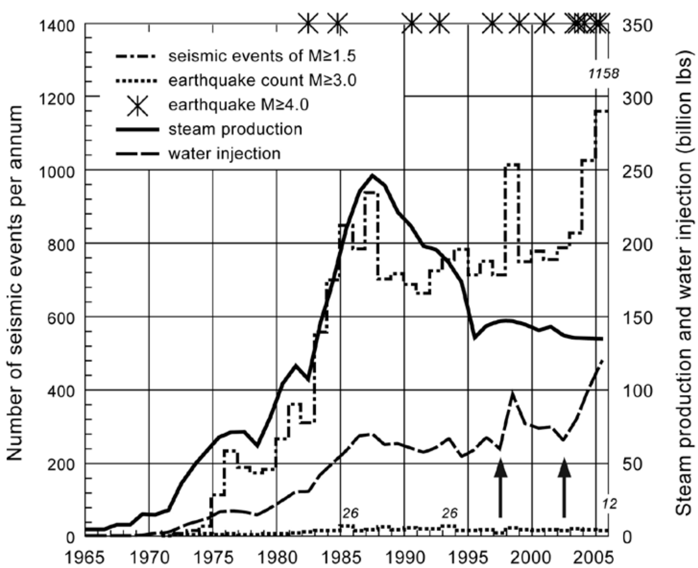


Figure 3. Historical seismicity from 1965 to October 2006 at The Geysers.

Data are from the Northern California Earthquake Data Center (NCEDC). The two arrows indicate the increases in fluid injection in 1997 and 2002. M: local magnitude; 1 billion lbs: 454 x 106 tons.

Seismicity in the vicinity of Power Plant 15, which ceased production in 1989, also ceased by the end of 1990. However, this has not been the case in the vicinity of the Central California Power Agency (CCPA) plant, where production ceased in 1996, but seismicity continued.

Since 1989, the SE Geysers area has experienced a long-term increase in earthquakes of magnitude 1.5 and greater. (The minimum magnitude for which long-term [1979 to the present] uniform detection threshold data are available is 1.5.) The same general trend of increased seismicity has been observed in the part of the SE Geysers study area within 3.2 kilometers (1.9 miles) of the Anderson Springs community. Figure 4 shows the locations of all seismic events in The Geysers field in October 2003, two months prior to start of injection of treated Santa Rosa wastewater. Figure 5 shows the location of all seismic events in The Geysers field in March 2004).[16]

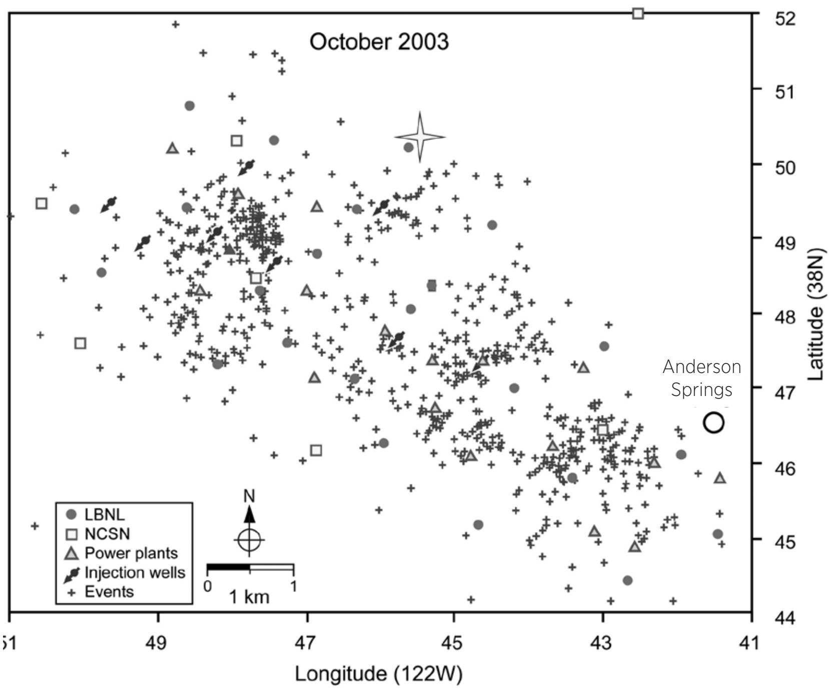


Figure 4. Location of all seismic events in The Geysers field in October 2003, two months prior to start of injection of treated Santa Rosa wastewater.

Squares: location of injection wells. Large star: approximate location of the magnitude 4.4 event of February 18, 2004. LBNL: Lawrence Berkeley National Laboratory; NCSN: Northern California Seismic Network of the USGS.

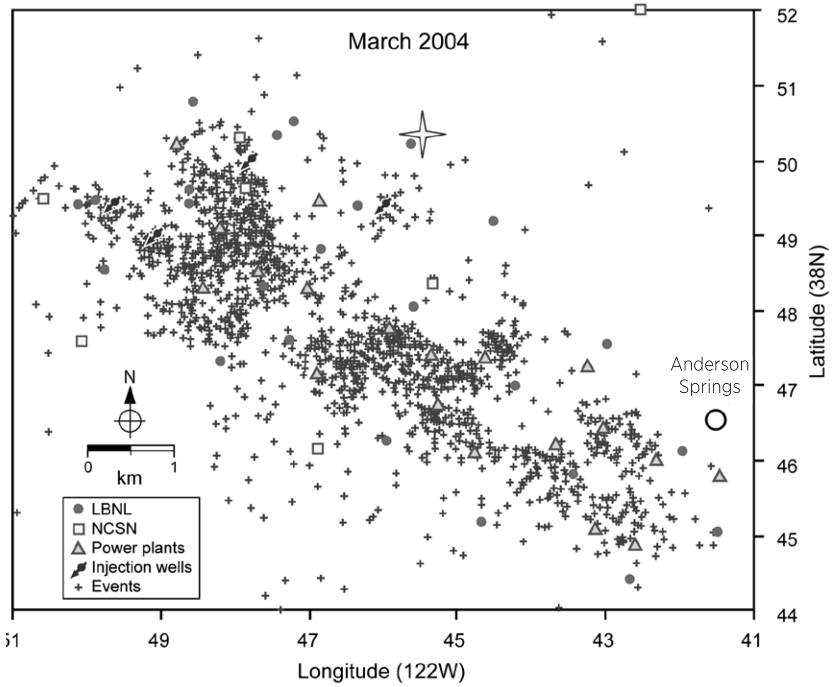


Figure 5. Location of all seismic events in The Geysers field in March 2004, after the start of injection of treated Santa Rosa wastewater.

Squares: injection wells. Large star: approximate location of the magnitude 4.4 event of 18 February 2004. LBNL: Lawrence Berkeley National Laboratory. NCSN: Northern California Seismic Network of the USGS.

In 2004 and 2005, after injection of wastewater from the Santa Rosa Reclaimed Water Geysers Recharge Project (SRGRP) began, the number of events with magnitudes greater than 4.0 increased. To help put this discussion in perspective, Figure 6 shows the location of seismic events with 3.0 < magnitude < 5.0 in all of northern California from January 1900 to mid May 2004.[16] Clearly, seismicity at The Geysers field is only a small part of the regional seismicity.

Researchers universally agreed that most of the earthquakes within the boundaries of the The Geysers field were induced by geothermal production and injection activities. Based on analyses of historical seismicity and supported by the intensive fracturing, the absence of continuous long faults, and the lack of alignment of earthquake epicenters, the largest earthquake believed to be possible at The Geysers is inferred to be of magnitude 5.0.[16/18]

Production-induced seismicity is very evident on a field-wide scale but is not tied to specific wells. This is because there are hundreds of producing wells, and the mechanical effects of steam production (principally reservoir pressure decline and heat extraction) are diffuse and spread into the reservoir.

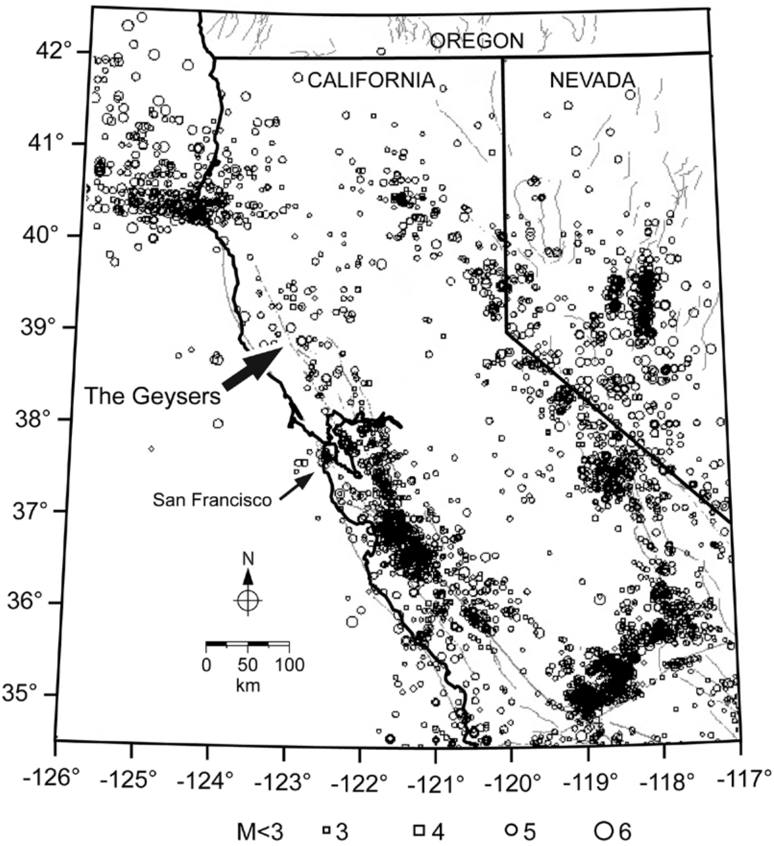


Figure 6. Location of seismic events in northern California with magnitudes greater than 3.0 and less than 5.0, from January 1900 to mid May

M: local magnitude. (Source: The Berkeley Seismographic Laboratory, Northern California Earthquake Data Center)

Indeed, seismicity occurs in reservoir regions much beyond the location of geothermal production and injection wells. Since 1987, while steam production substantially declined seismicity remained stable.[7/14/17]

Injection-induced seismicity is evident on a field-wide scale. In most cases, it is tied to a specific injector and shows a temporal downward migration. At injection wells, the seismic clouds generally appear shortly after injection begins, and seismic activity within each cloud shows good temporal correlation with injection rates. Injection-induced seismicity is generally of low magnitude, equal to or less than 3.0. On a field-wide basis, seismicity of magnitude 1.5 and greater has generally followed injection trends, but this correlation has not been observed for seismicity of magnitude 3.0 and greater.[7/14/17]

A preliminary analysis of the amplitudes of recorded earthquakes in the Anderson Springs area suggests that, theoretically, shaking large enough to be felt by residents occurs more than once per day. Measured peak accelerations are generally consistent with observations reported by residents; i.e. in the Modified Mercalli Scale II to VI range. However, reports of higher-intensity damage, such as the toppling of a large tree and a retaining wall, are clearly not consistent with seismicity as the singular cause.

1.1.3 The Geysers Coring Project

In addition to the study of seismicity, The Geysers Coring Project was another key component of research funded by DOE at The Geysers. The main objectives of this joint endeavor with industry, universities, and national laboratories were to 1) obtain a substantial length of continuous core from the steam reservoir for testing and analysis (little core was available from the reservoir itself), 2) advance knowledge of reservoir porosity and permeability, as well as fluid flow and fluid storage, and 3) refine existing models of the evolution of The Geysers geothermal system.[19] The project is described in the companion report on Exploration.

1.2 Cerro Prieto, Mexico

The Cerro Prieto field of northwestern Mexico, located approximately 30 kilometers (19 miles) south of the California border (Figure 7), is the world's largest water-dominated commercial geothermal power system. Located in the Mexicali Valley of Baja California, south of Southern California's Imperial Valley, Cerro Prieto is an abnormally large, hot (greater than 300ºC [572°F]) system hosted in sedimentary and metasedimentary rocks. The Comisión Federal de Electricidad (CFE), which owns and operates the field, began studying the Cerro Prieto field in the late 1950s.

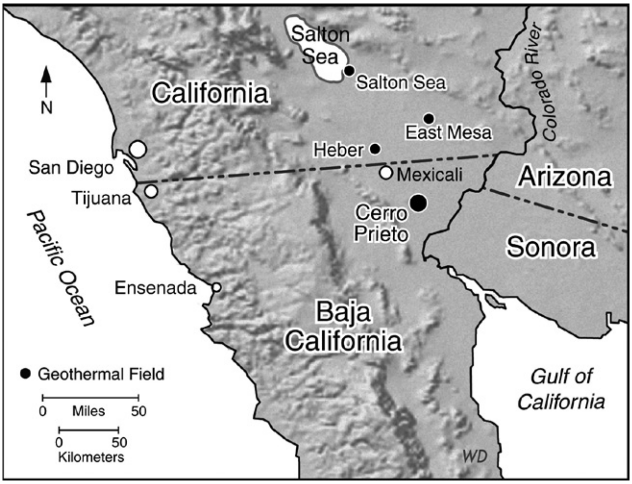


Figure 7. Location of Cerro Prieto geothermal field, Mexico

In 1977, CFE and DOE signed a five-year agreement to conduct a cooperative study of Cerro Prieto.[20] This agreement resulted in an intensive, collaborative study of the reservoir and publication of much pertinent information significantly advancing our understanding of these trough-type geothermal systems. A wide variety of existing and new geological, geochemical, geophysical, and reservoir engineering techniques was developed and tested. Due to its success, the formal cooperative program was extended for two more years to include studies of the Los Azufres and Los Humeros geothermal fields. Los Azufres is in the State of Michoacan in central Mexico, 90 kilometers [56 miles] east of the city of Morelia. Los Humeros is in Puebla State, about 200 kilometers [124 miles] east of Mexico City.

Studies of the Cerro Prieto geothermal field were not only instrumental in understanding how this large water-dominated reservoir behaved, but they also applied to the geologically related geothermal systems of the nearby Imperial Valley in Southern California. The results of the joint U.S.-Mexican effort were reported in a number of review articles and in the Proceedings of five joint conferences (see References Organized by Major Research Project Areas).

1.2.1 Cooperation in Reservoir Engineering

Beginning in 1979, LBNL, in collaboration with colleagues from CFE, initiated a study of the characteristics of Cerro Prieto production wells. Calculated downhole pressures, temperatures, and steam saturations in flowing wells, based on wellhead data, showed that from 1973 to 1980 pressures declined by about 15 bar and temperatures declined by 20°C (68°F). Steam saturation in near-well regions increased slightly over the same period. These studies underscored the sensitivity of computed downhole pressure to conditions measured at the wellhead and to well diameter.

Heat and mass production data for the period 1973 to 1980 showed that individual well production typically declined over time. This was due in part to relative permeability effects of steam and water, permeability reduction in the formation, and reduced reservoir pressure. Average enthalpy of produced fluids was variable over the period. A decrease in enthalpy was believed to result from the subsurface mixing cooler water with reservoir fluids. Increased enthalpy generally resulted from the entry of higher-enthalpy wells into production.

Researchers estimated the thermal energy contained in the reservoir at 23.8 x 10^{13} kilocalories, based on a minimum useful temperature of 200°C (392°F) and a maximum depth of 3,000 meters (9,800 feet) and the assumption that 25 percent of the resource in place could be extracted. Considering the efficiency of electrical power production, a total output of 31,600 MW-years was estimated. This corresponds to approximately 1,050 MW of capacity operating for 30 years.

1.3 Larderello, Italy

Larderello, in southern Tuscany, was the site of the world's first demonstration of geothermal power.[21-22] In 1904, emerging steam was fed to a small turbine that drove an electric generator that provided electricity to five incandescent light bulbs. Nine years later, the first geothermal power plant (250 kilowatts [kW]) was built at Larderello. Because field performance data are the basis for understanding the nature of any geothermal field, Larderello is especially significant: Its performance data go back to 1945. U.S. fields, by contrast, had been much less studied in the early and mid 1970s.

Like The Geysers, Larderello is a vapor-dominated geothermal system. Because nearby cool water aquifers are separated from the geothermal zone by low-permeability formations, meteoric waters from shallow external aquifers appear to have little to do with the field's output. Liquid water in the peripheral areas of the field is believed to result from condensation of steam originating from depth. The Larderello field's near-constant production of steam for power generation suggests a steady-state system as natural recharge to the system is minimal. The principal contributor to the field's production appears to be superheated steam rising from depth and the evaporation of water from the small pores of rocks in the underlying formation. These factors suggest that the system could be substantially larger than that currently known to exist.[23]

In June 1975, the Energy Research and Development Administration (ERDA), a precursor to DOE, and the Ente Nazionale per l'Energia Elettrica (ENEL) of Italy signed a cooperative research agreement covering five broad topics:

1. Stimulation of hot dry rocks and hydrothermal reservoirs,
2. Utilization of hot brine resources,
3. Reservoir physics, engineering, and resource assessment,
4. Deep drilling, and
5. Environmental control techniques.

The first topic was aimed at identifying sites appropriate for stimulation experiments, determining the techniques to be employed, and conducting the tests. Prior to 1980, most activity was information exchange. After observing a stimulation test at Larderello, LANL researchers applied the high-temperature well cementing techniques used by their Italian colleagues in tests at the Fenton Hill, New Mexico site. Plans were made to focus subsequent work on explosive stimulation of difficult formations. Italian researchers were invited to observe fracture stimulation tests at The Geysers, which were scheduled for mid 1980.

No mutually agreeable basis could be settled on for work under the second topic. In 1975, U.S. and Italian researchers felt the problems they faced in developing highly saline fields were similar, but further investigation found them to be sufficiently different to make collaboration unprofitable. Nevertheless, some limited data were exchanged.

The third area of American-Italian cooperation sought to optimize procedures for assessing geothermal resources and subsequent reservoir engineering. As a result of a year spent in Italy by a USGS researcher (September 1976 - September 1977), an ENEL report—"Geothermal Resource Assessment and Reservoir Engineering" (ENEL Studie Ricerche)—was published.[24] The report reviewed the application of resource assessment methods to specific case studies and efforts to apply techniques developed in the oil and gas industry to geothermal energy production.

Information generated from laboratory and theoretical studies performed by the Italian and U.S. researchers on the Larderello dry-steam geothermal system has been relevant to the exploration and exploitation of U.S. geothermal fields, particularly to the vapor-dominated Geysers system. The results of American-Italian scientific and technical cooperation are summarized in several articles published in two conference proceedings and in a special issue of the journal *Geothermics* (see References Organized by Major Research Project Areas).

1.4 Dixie Valley, Nevada

Dixie Valley, Nevada, a typical non-magmatic Basin and Range geothermal system, is one of the hottest (greater than 285°C [545°F]) and largest exploited geothermal resources in the United States.[25-26] Its energy arises from deep circulation to a high-heat-flux source with no apparent magmatic input. A complex network of fractures characterized the Dixie Valley geothermal system. Fluid flow results from both normal Basin and Range faulting and permeable rock formations. Flow paths are complex and marked by small-scale variability, suggesting that the longevity of energy production is related to production from a reservoir that is larger than would be expected if the Dixie Valley system were a simple planar fault system (Figure 8).[26]

From 1995 to 2002, DOE sponsored extensive research of the Dixie Valley system. As the largest, highest-temperature, deep-circulation geothermal system currently known in the Basin and Range province, Dixie Valley had particular significance for understanding and developing similar systems in the Basin and Range province. (The Dixie Valley geothermal system is also discussed in the companion Exploration history report.)

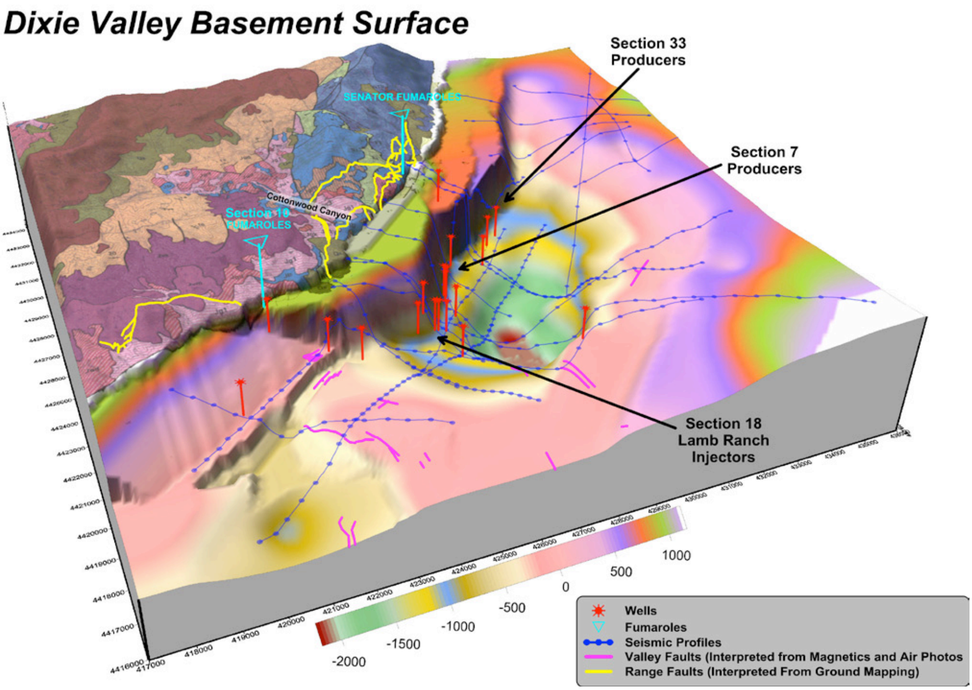


Figure 8. Simplified configuration of Dixie Valley Basement
(Cenozoic valley fill removed)

Based on seismic, gravity, drilling data and fault positions to limit contours. Geology shown for range (Speed [1976]).

When the Dixie Valley Power Partners (DVPP) lease was drilled south of the Dixie Valley production zone in 1993 and 1994, the high temperatures observed (285°C [545°F]) were so unexpected and deemed so significant that further study was begun to evaluate the implications of this new information for future geothermal exploration and assessment. The volume and variety of direct and indirect data for the Dixie Valley geothermal resource was greater than that available for any other geothermal area in the State of Nevada. Data sources included DOE-sponsored projects, data shared by DVPP, and open literature. Dixie Valley was the subject of seismic reflection surveys, surface geophysical surveys, and hydrologic and geochemical investigations.

Over three decades, in addition to detailed geologic mapping, 20 or more deep wells were drilled in the area. A similar number of seismic reflection profiles were performed mainly during the 1980s. Over 100 shallow thermal gradient holes were drilled, and multiple gravity surveys, electrical sounding surveys, and aeromagnetic surveys (at three altitudes) were conducted. The wealth of surface and subsurface information collected on the Dixie Valley geothermal system offered a unique opportunity to develop a detailed understanding of the system.

Output of the Dixie Valley geothermal field arises from two distinct areas: Sections 33 and 7 (Figure 8). Both sections are 1 to 3 kilometers (0.6 to 2 miles) long. At depth, the two sections are hydrologically separate from one another and from a third producing area, the DVPP area. Thermally, however, all three are similar. From cumulative studies over time, a single fault plane or set of parallel fault planes is not the best geological representation of the Dixie Valley geothermal system, as had been assumed before. Rather, a complex interlacing of fractures, with a spatially and temporally variable flow system confined to the most open parts of the system proved to be a better model of the system. Such a model is reminiscent of the vein structure of metal ore deposits. Results of studies conducted in Dixie Valley demonstrated that permeable pathways in this and similar systems are not obvious. Nevertheless thermal techniques, such as thermal-gradient holes, shallow temperature surveys (about 1 meter [3 feet]), and airborne infrared surveys are capable of locating them.[25]

1.4.1 Injection Augmentation

Evaporative cooling at a geothermal electrical power plant in the 50 to 60 MW range, such as the one at Dixie Valley, results in fluid loss ranging from 100 to 120 kilograms per second (800,000 to 950,000 lb/hr). If not counterbalanced by hot natural geothermal reservoir recharge, such a loss must be offset by long-term injection to maintain reservoir pressure. Even if all geothermal liquids produced are reinjected, pressure in the reservoir will tend to fall as a result of the evaporative loss.

Routine operation of the power plant and reservoir testing from 1985 to 1998 resulted in the loss of 69.5 billion kilograms (153.2 billion pounds) of fluid from the Dixie Valley reservoir, or over 30 percent of the total produced fluid. The resultant decline in reservoir pressure reduced output from the production wells. Operation of the power plant cooling tower and non-optimal handling of spent fluids contributed materially to this fluid depletion—accounting for some 4.5 billion kilograms per year (9.9 billion lb/yr). This loss was reduced to 3 billion kilograms/year (6.61 billion lb/year) by cooling tower improvements and operating changes. In spite of these improvements, reservoir pressure continued to decline at about 2.7 bar/year. To compensate for this pressure drop, five additional production wells were drilled in the first nine years of the project. The decreasing output of these wells over time signaled that this approach to stem declining field output did not offer a long-term solution.

Late in 1995, an injection augmentation plan was developed for Dixie Valley. Initial testing began in mid 1997. Excess injection capacity employing non-geothermal fluids was viewed as a more cost-effective way to reduce the rate of reservoir pressure loss or perhaps even reverse it, although injection capacity would probably have to increase over time. Full compensation for the cooling tower losses would require approximately 100 kg/s (793,656 lb/hr) of augmented flow, less any unknown natural hot reservoir recharge. Continuous injection of

100 kg/s into the reservoir would obviously require a very large source of water—difficult to find in the extremely dry Nevada climate where annual rainfall is 3 to 4 inches—and there is no nearby source of treated wastewater. However, because Dixie Valley is the lowest area in a system of seven interconnected valleys, groundwater can be found within 3 to 6 meters (10 to 20 feet) of the ground surface at the power plant site. The naturally occurring groundwater recharge to Dixie Valley is as large as 28.4 billion liters per year (7.77 billion gal/year). Moreover, when the valley became part of a military reservation, agricultural water-use ceased, leaving water rights available for non-agricultural activities.

An extensive field search for a source of suitable injection water was conducted, including evaluation of existing wells and the drilling of four exploratory wells to depths of 548 meters (1,798 feet). The goal was to identify a high-volume source of water at around 100°C (212°F) with minimal amounts of dissolved magnesium and calcium. Only very small volumes of water were found that met these criteria. Two of the exploratory wells, however, found steam in a shallow outflow plume from the reservoir that had not been detected. One well, 27-32, was subsequently put in service as an augmentation injection well. No source of ideal augmentation water was found, but an unused, 79-meter (259-foot) deep irrigation well near the power plant was able to deliver 125 l/sec (1,980 gal/min) of 25°C (77°F) water. As one of the few potential sources of injection liquid, a nine-hour step drawdown pumping test at rates of 63 to 126 l/sec (1,000 to 2,000 gal/min) was performed. Specific capacities of 11.7 to 7.7 l/sec-m were achieved, confirming the well's high productivity. A deteriorated section of casing was repaired, and a new slotted liner and electrically driven pump were installed. This well sustained pumping at rates as high as 133 l/sec (2,110 gal/min).[25] The availability of a large, unused and readily accessible source of groundwater permitted initiation of an injection augmentation program only two years after the plan was conceived—at less than half the cost (approximately $2 million) of drilling a production well or a deep injection well.[25]

FLUID CHEMISTRY

Geothermal fluid at Dixie Valley will deposit calcium carbonate scale when boiled, but the calcium content is low, around 6 mg/l pre-flash. The augmentation fluid, on the other hand, contained about 50 mg/l of calcium and a similar concentration of magnesium. When the cool augmentation liquid was mixed with 110°C (230°F) flashed brine, calcium carbonate and magnesium silicate could precipitate. Extensive field tests confirmed that such scaling would occur and would present problems. However, cooling tower overflow (steam condensate) at 40°C (104°F) could be mixed with the augmentation fluid without forming scale.

A dedicated injection well was required for the augmentation well, which in turn required that a low-temperature pipeline be built to supply the well. A 10-inch diameter, high-density polyethylene (HDPE) pipeline was laid on the surface, uninsulated, to supply injectors at the field's south end. In 1999, a 12-inch line was built to supply the injectors.

Water treatment companies were consulted to assess the feasibility of treating the groundwater to reduce its calcium and magnesium contents. The costs of such treatment in this once-through system proved to be prohibitive. In addition, securing permits for disposal of the concentrated waste stream from the treatment operation would be time-consuming and costly. Thus, a trial using untreated augmentation water was conducted in an expendable injection well to determine if treatment could be foregone. From 1997 to 1999, the augmentation program injected two million pounds of cold water directly into the reservoir. Since then, injection augmentation rates varied intermittently from about 200,000 to 425,000 lbs/hr.

INJECTION CAPACITY

To determine the individual capacities of the eight injection wells and possible combinations of capacities, the wells were step-rate tested. Since one injector had to be dedicated to cold water, the other seven wells had to be capable of handling all the hot injectate and cooling tower overflow. The capacities of the wells proved not to be the limiting factor, but pipeline and/or pumping limitations meant that certain wells and combinations of wells couldn't be dedicated to augmentation fluid injection. Given the constraints imposed by surface equipment capabilities, the wells best suited to cold water injection were identified through tracer tests. Reservoir pressure could be stabilized at an injection rate of 30 l/sec (476 gal/min). Higher injection rates tended to increase pressure. Natural reservoir recharge is therefore concluded to be about 70 l/sec (1,110 gal/min), given that the power plant cooling tower loss is 100 l/sec (1585 gal/min).

1.4.2 Monitoring

At the time when the Dixie Valley augmentation system was installed, several potential issues were deemed worth monitoring. In the near term, these included 1) subsidence in the vicinity of the groundwater well, 2) depletion of the groundwater resource, and 3) plugging of the dedicated injection wells and changes in geothermal reservoir pressure trends. In the longer term, cooling of the geothermal reservoir was of concern, as was scaling of production wells that were delivering recycled augmentation fluid. Tracer testing was considered as a discontinuous monitoring technique for the augmentation fluid flow paths.

Since the groundwater is pumped from unconsolidated alluvium adjacent to the power plant, ground subsidence was a concern. However, subsidence was not observed in the year and a half after augmentation began. In mid 1999, a microgravity station network was installed to more closely monitor the shallow groundwater system and the flow of injectate, among other purposes. Two small-diameter monitoring wells were drilled to depths comparable to that of the augmentation well and about 300 meters (1,000 feet) from it to gauge the effects of groundwater pumping on the aquifer. Measurements taken every few weeks showed that levels dropped about three meters at pumping rates of 60 l/sec (950 gal/min) and about twice that at rates of 133 l/sec (2,110 gal/min). These small drawdowns were reversible, suggesting the total groundwater resource was large and that land subsidence was likely to be limited.

No seismic events were recorded when injection augmentation was begun in July 1997 that could be attributed to thermal cracking of rock in the Dixie Valley reservoir.

To monitor the effectiveness of the carbonate scale inhibition program and any short-term trends toward increasing calcium, the calcium content of production wells was sampled weekly. Quarterly samples were also taken of brine from production wells and of augmentation fluid. These were subjected to standard water analysis. Tracer tests provided an indication of which production wells produced the largest volumes of augmentation fluid. No unusual increases of production well fluid calcium content were noticed, suggesting that the calcium in the augmentation liquid tends to precipitate in the fractures separating injection and production wells. Production well magnesium content did not increase. Observed reductions of production well chloride content suggested that sufficient volumes of augmentation fluid were entering production wells to influence the geothermal fluid chemistry, since the chloride content of the augmentation fluid was about half that of the produced fluid.

Reservoir pressure monitoring at Dixie Valley was employed to track the effectiveness of the augmentation program. Downhole pressure bombs were installed in three wells to provide continuous measurement of flowing well pressures. Two idle production wells were fitted with standard pressure bombs.

Reservoir permeability loss due to wellbore scale formation was a concern and prompted daily monitoring of injection well flow rates and pressures. No evidence of permeability loss was found. When injection well 65-18 delivered cold water, its flow rate doubled.

Because the injection of cool water places a greater load on the thermal resource of any geothermal field, the resource temperature will inevitably begin to decline when injectate is recycled. Dixie Valley's augmentation liquid absorbed twice the thermal energy of spent brine. Large geothermal fields will experience a slower temperature decline under these circumstances, and reversing such a trend will take longer once established. By 2000, a temperature measurement program had been put in place at Dixie Valley, with calibrated logging tools in selected production wells and experimental thermocouples in three wells (below the flash point) to provide continuous downhole temperature monitoring. From 1997 to 2000, eight tracer tests were run on all four injection wells into which augmentation fluid was pumped. The purpose of these tests was to ensure that injection wells receiving lower-temperature augmentation fluid provided the longest time for that fluid to absorb heat before it appeared at a production well. Results of those tracer tests directed changes of the injectors selected for augmentation fluid delivery.

1.5 Well Testing Campaigns

Under the DOE Geothermal Program several well testing campaigns were carried out in the late 1970s and early 1980s. The program also funded three well testing workshops that helped set the agenda for subsequent testing. LBNL organized these workshops.[27-29] In addition to the work done at Cerro Prieto, Mexico (see Section 1.2), DOE supported tests at East Mesa and Susanville, California; Raft River, Idaho; and Klamath Falls, Oregon.

Geothermal well testing is used to help quantify reservoir characteristics, including connectivity, reservoir and near-field (wellbore) permeability, and productivity. Well test data may also be used to infer unique characteristics, such as boundaries, seismically induced pressure transients, and two-phase wellbore or formation flow.[30] Specific tests used in past well testing campaigns have included injection, production, and interference testing.

As the name implies, injection tests use the injection of water to help determine the reservoir's pressure response. Step-rate injection tests act as a preliminary step for hydraulic fracturing treatments. Fluid is injected over a period of time at stepwise variable flow rates. The data gathered offers insight to flow rates and pressure required to successfully cause hydraulic fracturing.

Production tests consist of flowing production wells, either at a constant or stepwise variable rate. Down-hole pressures are collected prior to production, during production, and post-production, and they are used to infer the well's productivity index. Pressure data may also offer insight as to whether the reservoir is sufficiently fractured. In some instances, pressure data have been used to identify the existence of barrier boundaries.[31]

Interference testing involves both injection and production tests. However, instead of focusing on the particular well undergoing the test, observation wells throughout the same reservoir are observed for interference effects. As interference infers the state of the reservoir, the results may be analyzed and used to refine reservoir models.

For example, in 1983 a seven-week interference test, in which 50 wells were monitored, was conducted at Klamath Falls, Oregon. The objective was to determine the effect of geologic heterogeneity on the hydrologic behavior of the geothermal resource. During the test, water was continually pumped from a well on the margin of the field. During the last four weeks of the test the pumped water was injected into a second well. Throughout the test, pressure response was measured in the monitoring wells and demonstrated a non-linear pressure drawdown as a function of distance from the pumped well. The non-linear behavior indicated a composite reservoir system with a high mobility (product of permeability and thickness) inner region. A major range-front normal fault known to transect the area did not behave as a single linear fracture but as a broad region coincident with the high permeability region delineated by the interference test.[32]

As geothermal well testing varied both geologically and hydrogeologically, considerable experience was gained in geothermal well-test procedures, instrumentation, data acquisition, and data interpretation. These efforts resulted in many opportunities to identify and document geothermal reservoir engineering and geohydrological problems that have been useful to the U.S. industry.[33] Publications stemming from the DOE well testing campaigns are provided in References Organized by Major Research Project Areas.

1.6 Geothermal Reservoir Well Stimulation Program

From 1979 to 1984, DOE sponsored a series of 10 experiments in hydrothermal geothermal wells as part of the Geothermal Reservoir Well Stimulation Program (GRWSP).[34] The GRWSP was designed to assess the effectiveness of using stimulation techniques employed by the petroleum industry to improve the output of geothermal wells. Well stimulation was seen as having the potential to improve geothermal energy production more economically than re-drilling or replacing non- or low- producing wells.

Republic Geothermal, Inc. led the GRWSP effort. Maurer Engineering, Petroleum Training and Technical Services, and Vetter Research were subcontractors. LANL and Sandia National Laboratories (SNL) also collaborated in the DOE program. LANL experimented with explosive well stimulation at The Geysers; SNL conducted research in high-energy gas fracturing.

Starting in 1978, DOE researchers visited major well service companies to explain the Department's interest in evaluating stimulation techniques in high-temperature geothermal wells, assess the companies' interest in participating in field experiments, and offer them the opportunity to test any products they felt might be useful.

To be useful, geothermal well stimulation had to result in far larger fluid production rates than typical oil and natural gas wells. The permeability of geological formations near the wellbore must be significantly increased, or fractures created that offered very large flow conductivity over long periods of time. As a rule, achieving this performance requires that stimulation fluids be provided in large volumes and at high flow rates. Stimulation fluids, proppants, and equipment must perform—and be tested—at the high temperatures typical of the geothermal environment. The chemical compatibility of stimulation fluids and materials with the geothermal reservoir rock must also be verified.

Accordingly, GRWSP research commenced with reviews of oil and gas well stimulation technologies, including treatment design, evaluation methods, and the performance of stimulation fluids and mechanical equipment. Laboratory data were collected on the behavior of stimulation materials at high temperatures—fracturing fluids (including polymer-based fluids) and additives and proppants were tested to 260°C (500°F). The reaction products and solubilities of typical formation materials and drilling muds with acetic, formic, hydrochloric and hydrofluoric acids were evaluated at 175°C and 225°C (347°F and 437°F). Several calcium carbonate scale inhibitors were assessed for thermal stability. Four computer codes were modified to provide the capability to design and analyze field experiments.

1.6.1 The GRWSP Field Experiments

DOE's geothermal field experiments were conducted in proven reservoirs progressing from lower to higher temperature reservoirs. See Table 2[34] for a summary of these field experiments.

Table 2. Summary of Results of Stimulation Experiments

Experiment & Well	Formation Type	Treatment Goal	Stimulation successful?	Well Fixed?	Conclusions
1. Raft River RRGP-4	Fractured	Dendritic fracture	Yes, but long fracture	No	Flow rate too low
2. Raft River RRGP-5	Fractured	Long fracture	Partially	No	Flow rate low & fluid too cool
3. East Mesa 58-30	Sedimentary	Long fracture	Yes	Yes	Hydrofrac worked
4. East Mesa 58-30	Sedimentary	Long fracture	Yes	Yes	Hydrofrac worked
5. Baca B-23	Fractured	Fracture	Yes	No	Impermeable formation
6. Geysers OS-22	Fractured	Acidize	No	No	Fractures too short
7a. Baca B-20	Fractured	Long fracture	Yes. Fracture created.	No	Impermeable formation
7b. Baca B-20	Fractured	Acidize	Unknown	No	Permeability not increased
8. Beowawe R21-19	Fractured	Acidize	Probably	Partial	Injectivity increased 2.3 fold

GRWSP Experiments 1 and 2 were conducted at Raft River, Idaho in 1979. The relatively low temperature Raft River reservoir consists of naturally fractured hard rock at 143°C (289°F). A reverse-flow approach was used in well RRGP-4 in hopes of intersecting faults near the wellbore and creating a branched fracture pattern. Pressure build-up and video examination of the wellbore indicated a 60-meter by 100-meter (197 feet by 328-feet) fracture had been created. Well output increased by a factor of five, to some 13 metric tons per hour. At this flow rate, however, RRGP-4 was not commercial.

Well RRGP-5 was used for Experiment 2. The well approached the intersection of two major faults and was stimulated with a conventional hydraulic fracture treatment in an openhole interval of 66 meters (216 feet) near the wellbore bottom. In the original well completion, this fracture had channeled upwards. The well produced 50 metric tonnes/hr or only about 20 percent of the output of another well intersecting a nearby fracture. Due to its low temperature, the produced fluid from RRGP-5 was not deemed commercial.

East Mesa, California was the site of GRWSP Experiments 3 and 4, performed in 1980. The East Mesa reservoir is a mixed sandstone and siltstone formation of moderate temperature (160°C to 175°C [320°F to 347°F]). Well 58-30 was completed with a cemented, jet-perforated liner and thus formation zones could be readily isolated for treatment. Experiment 3 was a planar hydraulic fracture in a sandstone interval of 75 meters (246 feet) lying near the well bottom at approximately 2,000 meters (6,562 feet) depth. The permeability of this zone was impaired by carbonate minerals. The aim of Experiment 3 was to create a linear flow channel of high conductivity. This sandstone zone was treated and then sanded back without testing to allow Experiment 4 to be conducted in a shallower interval with better permeability. This interval was some 90 meters (295 feet) thick and had been drilled with a bentonite mud that caused permeability losses near the wellbore. Treatment was aimed at creating multiple short fractures in the impaired zone around the bore. This zone was tested first and averaged 60 tonnes/hour, a 108 percent increase in the permeability-thickness product (kh). The sand was removed from the lower fractured zone, and the well flowed at 90 tonnes/hour, a 114 percent increase, making these experiments the GRWSP's most notable success.

Experiment 5 was performed in Well 23 in Union Oil Company's Baca, New Mexico field in 1981. An experimental, high-temperature Otis packer of ethylene-propylene-diene monomer (EPDM) synthetic elastomer was used to isolate an unproductive interval of 70 meters (200 feet) in the upper portion of the reservoir. After stimulation had been done, tests indicated a fracture had been created and successfully propped, but production fell to noncommercial rates, apparently due to low formation permeability in the vicinity of the fracture. LANL made microseismic measurements which suggested that a zone about 700 meters long by 200 meters wide by 400 meters deep (2,296 feet long by 656 feet wide by 1,312 feet deep) was active. This seemed to indicate that failure of formation rock had occurred in a zone of considerable size. One fracture about 160 meters long by 100 meters high (525 feet long by 328 feet high) might have been created, but the researchers could not establish this definitively.

In January 1981, Experiment 6 was conducted at The Geysers. Hydrochloric acid was used in an attempt to etch discrete flow channels in the fracture faces of Union Oil's Ottoboni State 22 well. The acidification treatment had no effect on well productivity probably because the acid dissipated into natural microfractures in a 200-meter (656-foot) openhole interval.

GWRSP Experiment 7 was conducted at the Baca, New Mexico site in 1981, this time in Well 20. In an effort to improve on the results of Experiment 5, a high-viscosity frac fluid with sintered bauxite as the proppant was injected into a deeper, higher-temperature interval of 80 meters (262 feet) at a depth of 1,600 meters (5,249 feet). This interval, which was responsible for only a small part of the well's output of 25 tonnes/hour, was isolated for the experiment. At 282°C (540°F) Experiment 7 was the highest temperature interval fractured under the GWRSP.

The high-temperature EPDM packer was used again successfully. A very conductive fracture was created based on testing performed after stimulation, but overall, the productivity of Well 20 was low. Because of suspicions that finely divided calcium carbonate used as a fluid loss additive during fracturing had resulted in some plugging of the formation, Experiment 7 was followed by an acid treatment (Experiment 7A) that hopefully would remove the calcium carbonate. This acidification was unsuccessful. Before fracturing, injection tests were run, indicating that as much as half the injected fluid had entered an unproductive fractured zone below 1,500 meters (4,921 feet). The productive zone was above this, at a depth of about 1,200 meters (3,937 feet).

Experiment 8 was performed at Chevron's Rossi 21-19 well in the Beowawe, Nevada field in 1983. A fractured volcanic sequence, the Beowawe reservoir exhibited temperatures in the range of 180°C to 215°C (356°F to 419°F). Although known to intersect a high-temperature fluid zone, the Rossi well was not commercial, supposedly due to limited near-wellbore permeability. Test results bore this out. The low productivity was a local anomaly. All of Chevron's other wells produced in the range of 100 to 145 tonnes per hour, and there was hydraulic connectivity among them. A two-stage acid treatment was performed, involving the injection of 227,000 liters of hydrochloric acid followed by hydrofluoric acid (HF) into an interval below 1,330 meters (4,363 feet) with a slotted liner. The hydrochloric acid stage of treatment was intended to preclude calcium fluoride precipitation during the HF stage. The treatment resulted in injectivity increasing 2.3 times, but mechanical problems precluded an adequate production test. The effectiveness of the acid treatment could not be determined, and because post-treatment tests couldn't be completed, Experiment 8 was considered unsuccessful.

1.6.2 Well Stimulation Experiments Using Explosives and HEGF

At Unocal's Geysers well FL-30, Physics International Company conducted an explosive stimulation experiment in 1981 under the management of LANL. A charge of 364 kilograms (802 pounds) of HITEX II liquid explosive was emplaced at 2,256 meters (7,401 feet) depth and found to be safe after 48 hours at temperatures as high as 260°C (500°F). The next test involved 5,000 kilograms (11,023 pounds) of explosive contained in a 190-meter (623-foot) aluminum tube at 1,697 meters (5,567 feet) depth. In spite of test results indicating the explosives had reduced the near-wellbore skin factor, there was a 35 percent reduction of both the kh and steam flow. These effects were believed to result when rubble generated by the first explosion blocked two steam entry zones. Explosive stimulation was generally regarded as apt to cause near-wellbore damage.

SNL scientists undertook the development of slower-burning propellants in an effort to force fractures some distance from wellbores, since explosives tend to pulverize and compress rock due to very rapid detonation. SNL termed its approach “high-energy gas fracturing” (HEGF). To test this stimulation method, five boreholes at the DOE Nevada Test Site were subjected to HEGF experiments. The results showed that multiple fractures could be created that linked a water-filled bore with other fractures. The fractured region was excavated to determine the extent and direction of fractures. SNL found that fractures could be created in perpendicular directions through use of a slotted liner designed for this purpose. This suggested the possibility of forcing fractures parallel to the least principal stress in rock, thus breaking through to existing fractures, which are usually expected to lie perpendicular to the least principal stress. The parallel fractures were shorter (0.5 to 3.0 meters [1.6 to 9.4 feet] than perpendicular fractures, one of which was 6 meters (19.7 feet) long. Nonetheless, the experiment indicated that HEGF could be useful in repairing near-wellbore damage. A model was developed to predict fracture formation in such experiments as this one, and it proved to be generally useful.

1.6.3 Findings and Conclusions

Prior to DOE’s field experiments, there was little information available on the efficacy of geothermal well stimulation. Absent that information, there were several concerns regarding the usefulness of well stimulation technologies developed for oil and natural gas production. Several of the more important concerns are summarized as follows:

- Hydraulically induced fractures in geologic formations might parallel natural fractures and thus fail to intersect them, limiting the potential improvement of the formation permeability.
- Polymer-based fracture fluids might degrade rapidly in the high-temperature geothermal environment, preventing effective growth of fractures and restricting entry of proppants.
- Downhole mechanical equipment developed for oil and gas production might be inadequate for fracturing high-temperature wells.
- Proppants that performed adequately in hydrocarbon production wells might degrade in the hot, saline environment of geothermal wells, limiting the durability of any permeability increases achieved.
- Naturally fractured formations might permit rapid dissipation of stimulation fluids, leading to an early end of fracture growth.

GRWSP field experiment results tended to confirm that the first concern was valid.

Results of Experiments 3 and 4 at East Mesa and perhaps those of Experiments 5 and 7 at Baca somewhat allayed concern regarding thermal degradation of polymer-based fracturing fluids and the resultant failure of proppants to perform as intended. Fracture propping was apparently successful at East Mesa and may have been at Baca, although results at the latter site were equivocal.

Well pretreatments with cool water were successful in allowing conventional downhole mechanical equipment to perform adequately and thus answered the third concern. Since there was no long-term monitoring of productivity increases in stimulated wells, the GWRSP cannot be said to have put to rest the fourth concern over proppant durability. Results of some of the GWRSP experiments, particularly at Raft River, Idaho, lent credence to the fifth concern over fracturing fluid loss in highly permeable formations and the concomitant termination of fracture growth.

In the Baca and Raft River experiments, DOE decided to confine fracturing treatments to short, unproductive intervals. This decision was based on two premises. The first was that fracture technology from the petroleum production industry could create fractures in unfractured rock. The second premise was that zone isolation would be required to limit the height of fractures at the face of the wellbore to achieve the desired fracture width and the horizontal fracture extent. This approach meant that experimental wells had to be recompleted to isolate as much as 90 percent of the existing open interval. But because reliable methods to temporarily isolate open wellbore intervals were unavailable, practically all of the well's unstimulated production had to be sacrificed in order to effectively isolate the planned stimulation zone. This was deemed to be necessary in order to reduce the risk of complete failure and to enable the experimental results to be more easily evaluated. Unfortunately, in the Raft River and Baca experiments isolation of intervals that had been productive unavoidably limited the achievable well productivity, contributing to the conclusion that these experiments were commercial failures.

Concerns also surrounded acid treatment for well stimulation. These included:

- High temperatures were expected to influence the rates of reactions between the acids and formation materials. The magnitude of such effects was unknown.
- There was a scarcity of data on the solubilities of formation rocks and acid-rock reaction products in treatment acids. Such data were needed to facilitate treatment design.
- Acidizing fracture zones may not create sufficient fracture conductivity to make acid stimulation successful.

Laboratory experimentation provided data to largely respond to the first two concerns, but the results of DOE's field experiments were not uniformly positive enough to definitively dispose of the third concern.

Within the above limits, GWRSP field experiments showed that properly applied fracturing and acidizing could repair near-wellbore formation damage and improve the productivity of wells that penetrate local, low-permeability reservoirs.

Although frac treatments in Raft River and Baca significantly improved output from well intervals that had been unproductive, they failed to raise well production to levels that would support commercial operation. In some cases, this was due to low fluid temperatures, alone or in conjunction with low flow. These results supported the view that hydrofracturing stimulation of wells in fractured zones is unlikely to convert low-production wells into commercially successful ones.

DOE's experiments were performed mainly on low-productivity wells, leaving open the question of whether better results could have been realized if the same stimulation techniques had been applied to better-performing wells. This possibility could not be excluded at the time, but more productive completed intervals might in fact be less susceptible to permeability increases from hydraulic fracturing since fracturing fluid would tend to dissipate into the fractured zone. Likewise, several of the completed wells DOE experimented on had pre-existing completion problems that either constrained what stimulation treatment(s) could be considered or that affected the results of the applied treatments.

Well owners are naturally reluctant to risk damage to intact, productive wells from stimulation experiments, which may explain why DOE's GRWSP experiments were largely limited to minimally productive wells. Future experimentation with wells offering modest rather than minimal productivity was recommended. The ability to map the subsurface and develop a more detailed picture of reservoir and fracture geometry was also lacking at the time of the GRWSP work. Such knowledge could have materially assisted in establishing whether natural fractures were near the wellbore and whether hydraulically created fractures could effectively intercept them.

While GRWSP research produced important results regarding the value of well stimulation, few findings were reported in referred journals at the time. Nonetheless, the program collected valuable baseline data for ongoing efforts to improve the productivity of hydrothermal wells.

2.0
Hot Dry Rock

Between 1974 and 1995, LANL staff developed and tested two separate, confined hot dry rock (HDR)[35] reservoirs at the Fenton Hill HDR Test Site in the Jemez Mountains of north-central New Mexico, about 20 miles west of Los Alamos (Figure 9). The Atomic Energy Commission (AEC) initially sponsored LANL's HDR research, followed by ERDA, and finally DOE. The Federal Republic of Germany and Japan contributed significant funding and technical staff through an International Energy Agency (IEA) agreement.

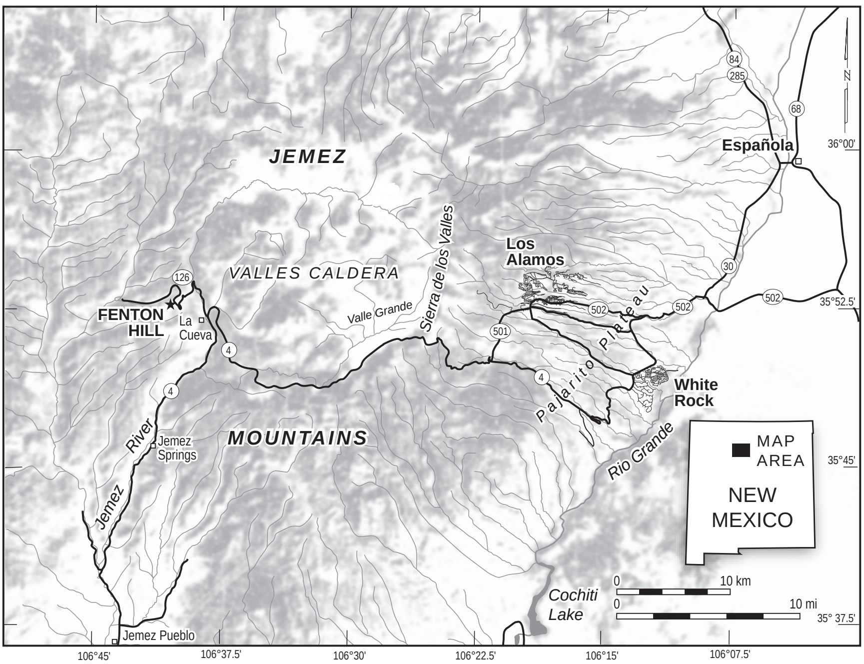


Figure 9. The region west of Los Alamos. The Fenton Hill area is shown west of the Valles Caldera.

Two man-made reservoirs were created in granitic basement rock at mean depths of 2,800 meters and 3,500 meters (9,200 feet and 11,500 feet), and temperatures of 195°C (380°F) and 235°C (460°F), respectively. The two reservoirs illustrated the complexity of HDR reservoir development. The Phase I reservoir was characterized by a set of near-vertical joints striking between

N55W and north, which evolved into a multiply connected network of joints with extension pressures in the range of 1,500 to 2,000 pounds per square inch (psi) (10 to 14 MPa). In contrast, in the Phase II reservoir—only several hundred meters deeper—an interconnected array of inclined joints was pressure-stimulated. These joints had extension pressures of about 5,500 psi (38 MPa).

LANL's HDR work was carried out in three major stages:

1. The Early Days (1970–1973): Concept development and tests in Barley Canyon
2. Phase I Drilling and Testing (1974–1980): The First Reservoir at Fenton Hill
3. Phase II Drilling and Testing (1981–1995): The Second Reservoir at Fenton Hill

Figure 10 is a photograph of the Fenton Hill, New Mexico HDR site.

Figure 10. Fenton Hill, New Mexico Hot Dry Rock program site

(Courtesy: Donald W. Brown)

2.1 The Early Days (1970–1973)

The genesis of the idea of "hot dry rock geothermal energy" belongs to Bob Potter, then a chemist at LANL.[36-37] In 1970, Potter formalized this new geothermal energy concept in a laboratory report on a new type of rock-melting drill.[38] According to Potter's concept, the heat contained in a previously tight region of hot basement rock could be accessed through the use of hydraulic pressure to create a very large, vertical "hydraulic fracture." The heat could then be recovered via closed-loop circulation of pressurized water. The HDR concept would be patented three years later.[39] Figure 11 shows the original HDR concept.[38]

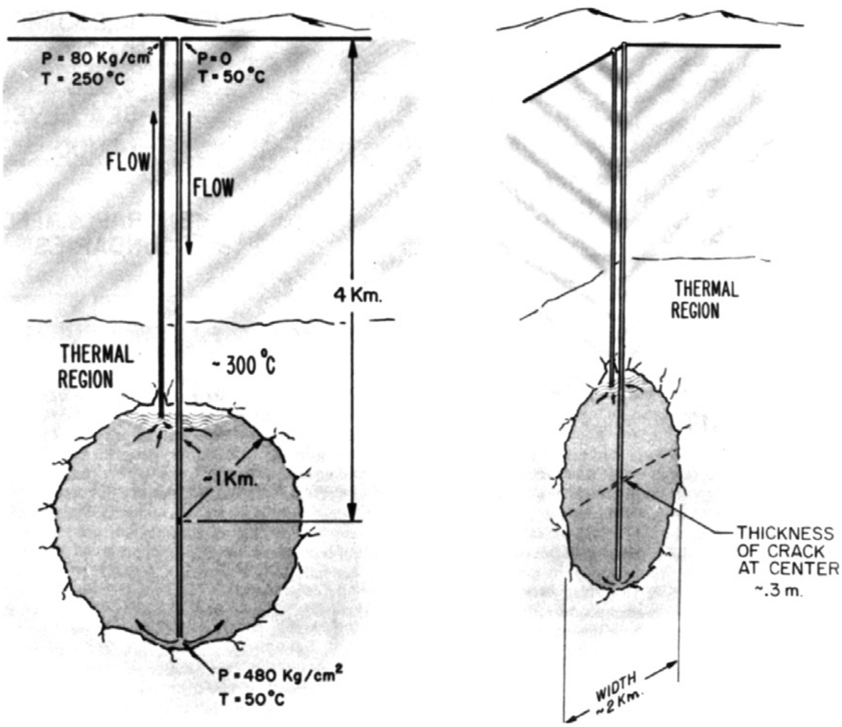


Figure 11. Originally proposed concept for a Hot Dry Rock geothermal energy system

Potter's idea did not include, or intend to include, the pressure-stimulation of marginal "hydrothermal" systems. Hydrothermal systems are relatively rare, underlying only a very small fraction of the earth's surface. In contrast, the heat contained in those vast regions of the earth's upper crust (the HDR resource base) represents the largest and most broadly distributed supply of directly usable thermal energy.[40]

During 1971, the HDR team at LANL[41] collected and studied the literature on hydraulic fracturing, rock mechanics, and geothermal energy in general. They reasoned that a region near the Valles Caldera (just west of Los Alamos) would be an ideal setting for the first HDR experiment. In December of that year, they began drilling a series of shallow heat-flow holes on accessible U.S. Forest Service land surrounding the caldera. The data from these tests showed that as this large region was surveyed, first to the east, then around to the south, and finally to the west of the caldera, the temperature gradients increased. In the spring of 1972, three deeper boreholes were drilled along an arc west of the ring fault structure. As expected, heat-flow measurements in these holes showed elevated values (Table 3).

Table 3. Heat-Flow Values in Intermediate-Depth Test Holes

	Hole A	Hole B	Hole C
Date completed	10 April 1972	13 April 1972	16 April 1972
Distance from ring fault (miles)	2.0	2.4	3.0
Depth (feet)	590	650	750
Heat flow (cal/cm^2 – second)	5.13 x 10–6	5.50 x 10–6	5.88 x 10–6

In late 1971, roughly concurrent with LANL's early fieldwork on HDR geothermal energy, the U.S. Congress directed the AEC to assume new responsibility for R&D related to all aspects of both non-nuclear and nuclear energy supply, conversion, distribution, and storage. On December 7, 1971, the AEC established the Division of Applied Technology (DAT) to oversee its non-nuclear activities. Fortuitously, in late November, LANL had included a two-page section on "Exploitation of Dry Geothermal Energy Reservoirs" in a report to the AEC on the laboratory's R&D activities. The report suggested that the AEC could now appropriately undertake an investigation of the HDR concept.

With the prospect of DAT funding for HDR research, LANL amassed a pool of otherwise uncommitted funds to drill Granite Test 1 (GT-1), the first exploratory borehole into the crystalline basement underlying the Fenton Hill region. GT-1 was spudded (i.e., began drilling operations) on May 9,1972 in a reasonably flat region of Barley Canyon. Most sections of the canyon were fairly steep. The site was selected for its location along the arc of the heat-flow test holes (Table 3) and because its canyon-bottom elevation would save about 91 meters (300 feet) of drilling. The site turned out to be difficult. During the summer "monsoon season" in the Jemez Mountains and the very severe winter that followed, Barley Canyon was often so muddy or snowy that the site was inaccessible.

Precambrian crystalline basement rocks were encountered at 642 meters (2,105 feet). By June 1st the hole had reached a depth of 741 meters (2,430 feet), some 100 meters (325 feet) into the basement. After being cased to a depth of 2,400 feet with 5-inch-diameter, 13 pound per foot (lb/ft) K-55 casing, the hole was deepened

44 meters (145 feet) by continuous coring. The final depth was 785 meters (2,575 feet)—143 meters (470 feet) into the crystalline basement. An examination of the drill cuttings obtained during the first 100 meters of basement drilling (before the casing was set) showed that the rock was primarily augen gneiss. The rocks penetrated during the continuous-coring phase were 15 meters (50 feet) of granite, 12 meters (40 feet) of gneiss, and 17 meters (55 feet) of amphibolite. This first exploratory borehole exhibited a bottom-hole temperature of 100.4°C (212.7°F) and a mean gradient of over 100°C/kilometers (212°F/kilometers)—outstanding for any geothermal area.

In early 1973, Los Alamos conducted a series of hydraulic fracturing experiments with considerable difficulty in the 44-meter (145-foot) continuously cored Precambrian interval of GT-1. These first-ever "fracturing" experiments in deep, hot crystalline rock were intended to verify the suitability of such rocks for field testing of an HDR reservoir.

In conventional hydraulic fracturing of sedimentary formations containing petroleum or natural gas, a "packed-off" interval of the borehole is pressurized until the overpressure fractures the borehole wall. According to the then-accepted theory of hydraulic fracturing in unjointed sedimentary formations ("homogeneous" isotropic rock) in regions where the earth stresses are typical (i.e., the maximum earth stress is vertical), the induced fracture should be vertical, planar, and normal to the axis of the least principal earth stress, which acts horizontally. With continued pressurization, the fracture should extend radially outward from the borehole for hundreds of feet, forming what is referred to as a "penny-shaped vertical fracture." This theory formed the basis for the original HDR system design (Figure 11).

But when the Los Alamos team applied this simple theory to the hydraulic fracturing of the Precambrian crystalline rocks penetrated by the GT-1 borehole—as though this melange of ancient metamorphic and igneous rocks were "unflawed and homogeneous"—they actually made a serious error in judgment. The investigators all assumed that a single fracture would be created and that it would be penny-shaped and vertical, providing a large area for the exchange of heat between the surfaces of the fractured hot rock and the circulating fluid. Worse, as it turned out, that error was perpetuated in HDR geothermal programs carried out later in other countries and in HDR research conducted by several universities (much of which, at least initially, was supported by Los Alamos).

This concept was not abandoned until the early 1980s (even later in Japan). Eventually, both the British HDR team working at Rosemanowes in Cornwall and the Los Alamos team realized that, except for possibly a short distance immediately adjacent to the borehole wall, hydraulic fracturing was not actually breaking open intact crystalline rock against its inherent tensile strength. Rather, pre-existing—but sealed—joints were being opened. The conventional theory of hydraulic fracturing had ignored the presence of these flaws in the basement rock.

The AEC's Division of Physical Research funded these first attempts to fracture the basement rock. The attempts were uniquely successful and would not soon be replicated, for three reasons:

1. Because this section of the GT-1 borehole had been drilled with diamond core bits, the borehole wall was very smooth, enabling many short intervals to be isolated with straddle packers.

2. The diameter of the borehole was only 4 ½ inches, allowing the use of smaller and more efficient packer elements. (The success of sealing with packers appears to decrease inversely with the hole diameter.)

3. The working depths were fairly shallow, making the numerous packer repairs relatively easy.

The three-step fracturing plan for GT-1 was 1) to isolate, and then hydraulically fracture, seven short intervals (2.1 to 2.7 meters [7 to 9 feet]) within the cored open-hole section of the borehole; 2) to pressurize the interval encompassing all the mini-fractures in the hope that they would coalesce by using a bridge plug set just below the deepest mini-fracture and an inflatable packer just above the shallowest; and 3) to extend the single composite fracture radially outward with further pumping.

In the final fracturing experiment (April 4, 1973), an injection rate of 4.5 to 5 barrels per minute (BPM) (180–200 gallons per minute [gpm] or 12 to 13 liters per second [L/s]) was achieved with commercial pumping equipment. This experiment opened one large joint over the entire 35.6-meter (117-foot) straddled interval (from 739.7 to 775.4 meters [2,427 to 2,544 feet]). Borehole televiewer surveying indicated that this joint was essentially vertical (aligned with the almost vertical borehole), oriented approximately N45W, and connected all seven of the smaller aligned joint openings.

At that time, it was not well understood how the jointed crystalline basement would behave under pressurization. Previous hydraulic fracturing experience, in the oil industry, had been limited to sedimentary rocks. As the least principal earth stress is assumed to be horizontal, when extended, the composite fracture would be vertical and therefore perpendicular to the least principal stress line. From analyses based on the diagnostic tools available at this very early stage of the HDR Project, what appeared to have taken place is exactly that (even though the "fracture" was a resealed joint rather than a true hydraulic fracture). The only discernible feature was the single, vertical crack extending the entire length of the 35.6-meter (117-foot) straddled interval. Because these incomplete observations, which lacked any seismic verification, appeared to confirm the "vertical, penny-shaped fracture" theory, the LANL team stayed with its original model for an HDR system for the next several years (Figure 11).

In the spring of 1973, the DAT had yet to receive any geothermal funding. That all changed on June 28th when a New Mexico congressman violated a long-standing tradition in the U.S. House of Representatives. Traditionally, appropriations bills before the full house are not to be amended. However, the congressman offered an amendment to the bill adding $4.7 million for geothermal research ($3.0 million of which was slated for the Los Alamos HDR Program). It was the only amendment offered, and it passed. Finally, the DAT had a geothermal program and—after three years of begging and borrowing funds internally—Los Alamos finally had a well-funded HDR Program.

Meanwhile, the HDR team had been investigating other areas near Barley Canyon for the permanent HDR Test Site. Fenton Hill was tentatively selected. Fenton Hill was centrally located within a large, north-trending fault block just two miles west of the caldera ring fault structure, on the arc of the heat-flow test holes and GT-1. This suggested good heat-flow characteristics. In addition, it was adjacent to an all-weather state highway, was traversed by the main regional power line, was high and dry (at 2,650 meters [8,700 feet] elevation), and had nearby telephone service.

In the summer of 1972, an expert on earthquakes from the University of Nevada had spent five weeks investigating the fault structure and earthquake history of the Fenton Hill area. The expert assessed potential earthquake hazards associated with hydraulic fracturing operations. (A very large body of data already existed on Fenton Hill. The Valles Caldera—one of the classic calderas in the U.S.—and its environs had been extensively studied by a number of geoscientists in the preceding years).[42]

The findings from the 1972 investigations were reported in a laboratory publication.[43] Based on low-sun-angle photography and field studies, the presence of the known faults in the area was confirmed. A previously unmapped minor fault in Virgin Canyon was discovered 2.5 miles southeast of Fenton Hill. This fault had a very low average rate of movement, and trended away from Fenton Hill. There also appeared to be no earthquake hazard from other faults within a 15-mile radius of Fenton Hill. The Virgin Canyon Fault was the only fault found that had displaced the geologically young surface volcanics.

In addition, as part of this study, all available earthquake data for New Mexico were collected and analyzed. This analysis led to several conclusions: 1) the level of seismic activity in the region surrounding Fenton Hill was very low, 2) hydraulic fracturing experiments in this area involved very little seismic risk from natural fault activity or local earthquakes, and 3) such experiments were not likely to activate any of the known faults in the area—including the closest and most recent one in Virgin Canyon.

2.2 Phase I Drilling and Testing (1974–1980)

The drilling of the first borehole at Fenton Hill, GT-2, began on February 17, 1974. After a sequence of tests at intermediate depths of 1,920 to 2,040 meters (6,300 to 6,700 feet), drilling continued. The borehole reached its final depth of 2,832 meters (9,619 feet) on December 9th. Extensive testing was then carried out near the bottom of the borehole, including a set of "fracturing-through-perforations" injection tests through a scab liner that had been cemented in just off bottom. The perforation tests were not successful. Because the joints intersecting the borehole closest to any particular set of perforations were not very favorably oriented with respect to the stress field, injection into the straddled intervals of perforations invariably resulted in higher-than-expected injection pressures.

The final testing (i.e., pressure-stimulation of the 11.6-meter [38-foot] "rat hole" below the scab liner) opened a pre-existing but resealed joint with the modest injection of 1,800 gallons of water. The final joint-extension pressure was 1,700 psi (12 MPa). The strike of this near-vertical joint, which became the "target" joint for intersection with the second borehole (EE-1), was later determined as N27W.

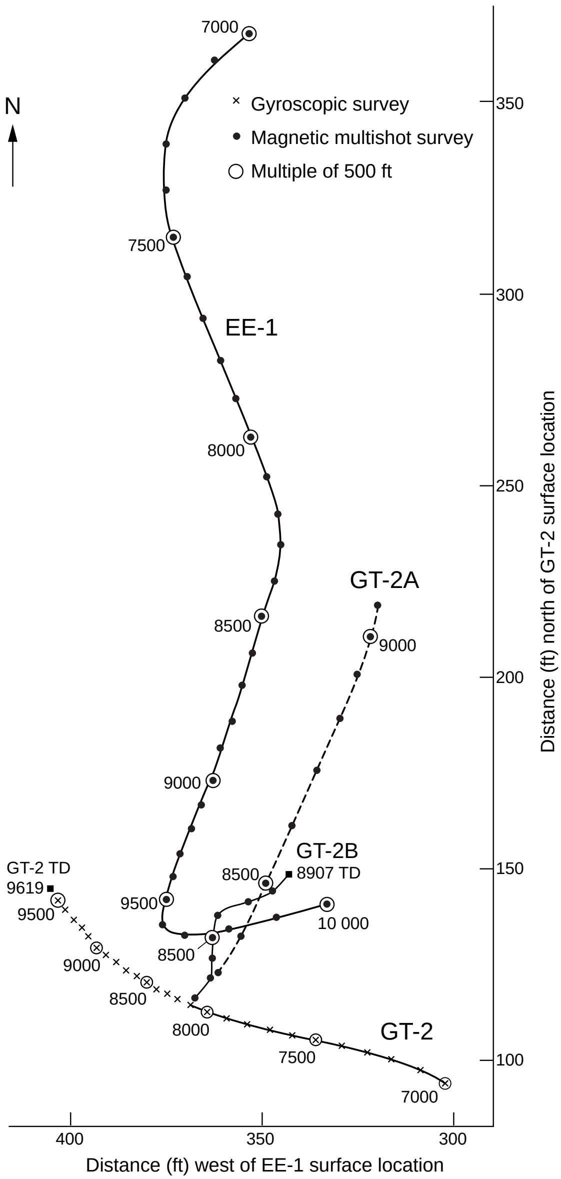
Beginning on May 26, 1975, the EE-1 borehole was drilled next at a location about 76 meters (250 feet) north of GT-2. EE-1 was drilled with a drift similar to that of GT-2 (about N70W), to a depth of 2,099 meters (6,886 feet). The trajectory was then turned to the south, and the lower portion of EE-1 was directionally drilled toward the bottom of GT-2. The plan was for EE-1 to pass about 60 meters (200 feet) below the bottom of GT-2. Although the strike of the GT-2 target joint was not yet known, it was assumed that whatever its strike, it would inevitably be intersected by drilling directly below the bottom of GT-2.

However, the EE-1 borehole approached the bottom of GT-2, a series of seismic ranging experiments was performed with detonators as the source of acoustic signals. Because of the 180° ambiguity in the direction of the seismic signals, EE-1 was inadvertently turned to the east about 8 meters (26 feet) short of the target joint at the bottom of GT-2. The HDR Project's claim that joining the boreholes would be like "hitting the broad side of a barn" had not allowed for the geophysical unknowns. Figure 12 illustrates the evolution of the Phase I reservoir.[44]

With the borehole geometry as shown by the EE-1 and GT-2 representations in Figure 12 (before the drilling of GT-2A and GT-2B), over a year was spent on trying to achieve a low-impedance flow connection between EE-1 and GT-2 by repeated hydraulic stimulations in EE-1. But the best impedance achieved was 24 psi/gpm, considerably higher than the 10 psi/gpm deemed necessary for an HDR power production system

By the end of 1976, Los Alamos had managed to develop a true HDR reservoir between the two boreholes, albeit of a volumetric nature. The flow geometry was

Figure 12. Plan view of the trajectories of the Phase I boreholes: EE-1, GT-2, and the two redrilled "legs" GT-2A and GT-2B



spread laterally rather than vertically—sufficient for an initial heat-mining experiment, particularly if stimulations at higher rates and pressures had been done before major flow testing. Instead, another year or more of effort was spent, including two redrillings of GT-2—all of which (not to mention the considerable costs involved) could have been saved if such an experiment had gone forward.

Following the second redrilling of GT-2 (GT-2B in Figure 12), an adequate flow impedance was achieved (about 10 psi/gpm), and the initial Phase I reservoir was flow-tested for 75 days in 1977 (Run Segment 2). This was the first successful operation of an engineered HDR reservoir in deep basement rock. The thermal power production of over 4 MW, although modest for this closed-loop circulation test, conclusively demonstrated the viability of the HDR geothermal energy concept.

In mid January of 1979, the bottom 183 meters (600 feet) of the EE-1 casing was re-cemented, and the Phase I reservoir was enlarged by pumping into the principal joint intersecting the borehole at about 2,940 meters (9,650 feet). This reservoir was flow-tested for over nine months in 1980 (Run Segment 5). Figure 13 shows the water-loss rate (recorded as makeup-water rate) for this test.[45]

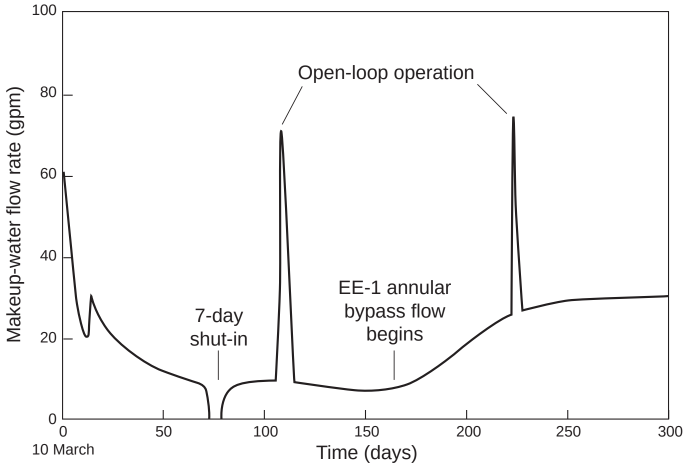


Figure 13. Water-loss rates during Run Segment 5

The most significant feature of this water-loss rate was a slow decline to about 7 gpm on day 150 (at which time a significant annular bypass flow began, up behind the casing in the injection well). The fact that the water loss was small and decreasing until this time indicates that the Phase I reservoir was confined at an internal pressure of about 1,400 psi (9 MPa) above hydrostatic.

Figure 14 shows the variation in the production temperature during the greater part of Run Segment 5 [adapted from 45]. Because the produced fluid was flowing across the same production joints connected to GT-2 that had been cooled to near 80°C (180°F) during the 75-day flow test (Run Segment 2), the reservoir production temperature actually rose for the first 60 days as those joints were re-heated. The temperature then dropped by about 15°C (60°F) during the remainder of Run Segment 5, to about 150°C (300°F).

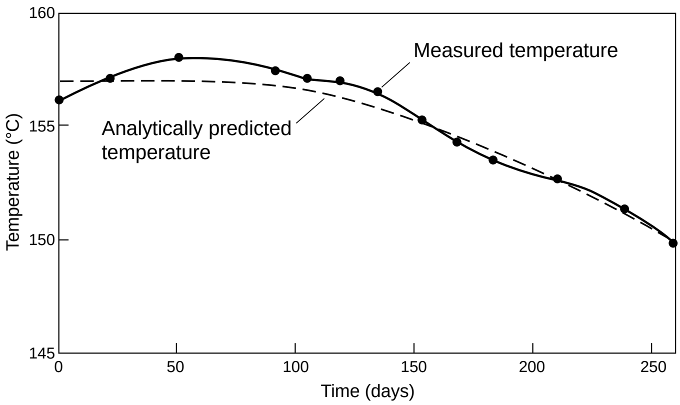


Figure 14. Measured variations in the production temperature during Run Segment 5

(an analytically predicted cooldown curve is included for comparison)

Table 4 summarizes the operating conditions for Run Segment 5.

PHASE I RESERVOIR TESTING
(March–December, 1980)

PARAMETER	VALUE	COMMENTS
Injection Pressure, MPa (psi)	9.7 (1400)	Declined near end of test
Injection Flow, L/s (gpm) Production Flow, L/s (gpm)	6.3 (100) 5.9 (93)	Final Final
Thermal Power, MW	3	Average
Backpressure, MPa (psi)	1.4 (200)	Average
Production Temp., °C	158	Average
Flow Impedance, psi/gpm	13	Average
Water Loss, L/s (gpm)	0.2 (2)	Final

Table 4. A summary of the operating conditions for Run Segment 5

2.3 Phase II Drilling and Testing (1981–1995)

The Phase I reservoir at Fenton Hill extended over the approximate depth interval of 2,400 to 3,000 meters (8,000 to 10,000 feet). It had successfully demonstrated the technical feasibility of the HDR concept, but at a production temperature (157°C [315°F]) and thermal power (3 MW) lower than desirable for commercial power production. The Phase II reservoir was planned for development at a depth of 3,700 to 4,300 meters (12,000 to 14,000 feet). This would test the HDR concept at a temperature and level of thermal power production more appropriate for a commercial power plant and with a reservoir large enough to sustain a high output of thermal power for at least 10 years.

To understand how and why the Phase II HDR system at Fenton Hill developed as it eventually did, it is necessary to note that the planning for this system was a "work in progress" from about mid 1979 through mid 1982. As late as the spring of 1979, while Run Segment 5 was under way to test the enlarged Phase I reservoir, the still evolving plan for the Phase II system called for drilling only one new borehole, EE-2. This new borehole would be used as the Phase II injection well, while one of the existing Phase I wells—probably GT-2—would be deepened to serve as the production well for the deeper and hotter system:

> *"This new well, EE-2 will be drilled to a total depth corresponding to a bottom-hole temperature of at least 275°C. We intend to create the new [HDR] system…with a heat-production capability of about 20 MWt. Further, we will use this system to demonstrate extended reservoir lifetime…for a [thermal] drawdown that will not exceed 20 percent in 10 years of operation."* [46]

The principal objective of the drilling program for EE-2 was to gain access to a large volume of hot rock at depths of 3,700 to 4,300 meters (12,000 to 14,000 feet) for subsequent reservoir development. On the basis of temperature-gradient data from the deeper portions of GT-2 and EE-1, where bottom-hole temperatures were about 180°C (360°F), attaining the desired reservoir temperature of 275°C (530°F) would require a true vertical depth (TVD) of about 4,300 meters (14,000 feet) for the new borehole. The desired rock temperature was actually reached at a TVD of only 3,870 meters (12,700 feet) because of the directional drilling of the EE-2 borehole toward the nearby Valles Caldera. With the temperature gradient increasing with depth below about 2,000 meters (6,500 feet), at the completion of drilling the bottom-hole temperature at 4,391 meters (14,405 feet) was about 317°C (603°F)—considerably hotter than the original target temperature.

Only after the drilling of EE-2 was under way did it become known that the next year would bring higher levels of funding to the HDR Program, in large part from contributions by the program's international partners, Germany and Japan. With this news, the plan to deepen GT-2 (or possibly EE-1) was abandoned in favor of drilling a second new borehole, EE-3—to be started immediately after the completion of EE-2. The drill rig would simply be skidded about 50 meters (150 feet) to the northwest. This decision was quite reasonable considering not only the small diameter of the casing in GT-2 (7 5/8 inches), but also the condition of EE-1 following the nine-month flow test that ended in December 1980 (Run Segment 5). By this time, a significant bypass flow had developed. Fluid was now flowing from the pressure-stimulated Phase I reservoir region, via the annulus above the cemented-in portion of the casing in EE-1, to the surface—in parallel with the production flow in GT-2B.

The development plan for the Phase II HDR reservoir stipulated that the lower portions of the injection and production wells would be directionally drilled—which would be both expensive and difficult. The rationale was based on the critical yet erroneous assumption that 1) the continuous, near-vertical, northwest-striking principal joints observed in the Phase I reservoir region between about 2,400 and 3,000 meters (8,000 and 10,000 feet) would also be present some 1,200 meters (4,000 feet) deeper into the structurally complex Precambrian basement, and 2) these joints would control the development of the Phase II reservoir. The Phase II reservoir development plan built on this assumption is shown in Figure 15 (size and depth of the low-velocity region adapted from references 47 and 48).

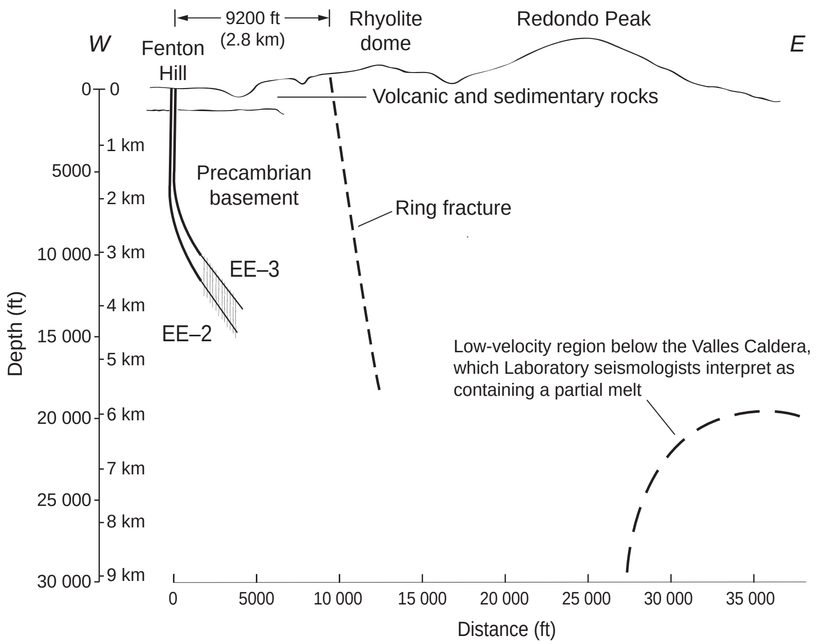


Figure 15. The Phase II reservoir development plan, showing the proposed EE-2 and EE-3 boreholes in relation to the geological setting

The Phase II plan called for drilling EE-2 and EE-3 vertically to a depth of about 2,000 meters (6,500 feet) and then directionally toward the east (that is, roughly across the strike of the two principal vertical joints that had been pressure-opened in the Phase I reservoir). The lower portions of the two boreholes would be drilled to position EE-3 directly above EE-2, with a vertical separation of about 370 meters (1,200 feet). The planned final inclination of the boreholes was 35° from the vertical. This way, starting from the bottom of EE-2 and working upward along the borehole, up to 12 intervals could be sequentially isolated with inflatable packers and separated by about 50 meters (160 feet). Each interval would be pressurized to create a vertical "fracture" that would then be driven upward to intersect the EE-3 borehole. The trajectories of the two boreholes as completed are shown in Figure 16.[49]

The following events are covered in the remainder of this section: 1) the attempts to create an open, jointed reservoir region connecting the Phase II boreholes by sequentially pressure-stimulating each; 2) the eventual redrilling of the EE-3 borehole to intersect the EE-2 stimulated region; and 3) the brief flow testing of the completed Phase II reservoir. These three events are the most significant events of the Fenton Hill Project. These experiments and flow testing revealed the major features of the deeper HDR reservoir. They represent by far the steepest part of the "learning curve" in HDR reservoir engineering.

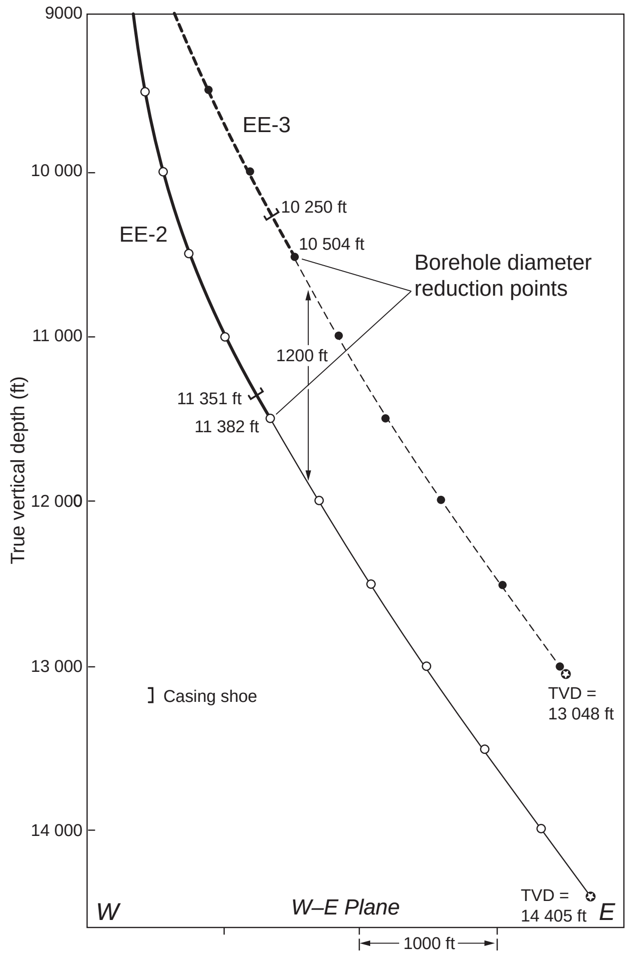


Figure 16. Trajectories of the completed EE-2 and EE-3 boreholes
(projected onto an east-west vertical plane)

As noted earlier, the joint structures encountered during development of the Phase I reservoir gave rise to the assumption that the principal joints in the Phase II region just below would have a similar orientation—essentially vertical and striking northwest. Instead, the principal, more continuous joints in this deeper region were found to be significantly inclined from the vertical, having therefore much higher opening pressures.

The project managers were convinced on the basis of the "penny-shaped fracture" theory that with sufficient pumping, hydraulic fractures could be opened deep in EE-2 and then driven vertically upward to intersect EE-3. After two failed attempts using inflatable packers, a scab liner was cemented deep in EE-2, and several pressurizations were carried out in the 136-meter (447-foot) open-hole interval below the liner. Although no hydraulic communication was established with EE-3, even after the injection of almost 1.3 million gallons of water during the last deep pressurization test, there were seismic indications that a large, pressure-stimulated region had been created around and above the bottom of EE-2. In section view, the poorly located microseismic events were concentrated in a relatively thin tabular region dipping to the west at about 45° and passing below the bottom of EE-3. Figure 17 shows the locations of microseismic events recorded for one hour on June 20, 1982, during the first steady-state period. The wireline-deployed triaxial geophone was positioned at a vertical depth of 2,937 meters (9,635 feet) in EE-1.[50]

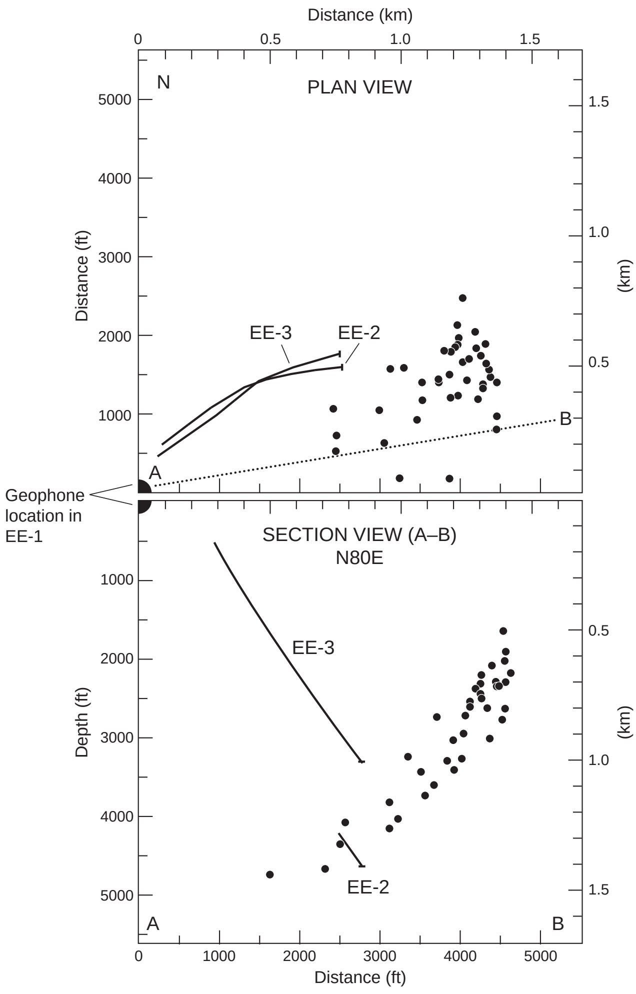


Figure 17. Locations of microseismic events recorded for one hour (12:30–13:30 on June 20, 1982) during the first steady-state period

In June 1982, after only three weeks of serious testing of the bottom of EE-2, the project managers decided to sand up and abandon the 1,100-meter (3,600-foot) lower section—which had been so difficult and expensive to drill. Motivated to achieve a connection by whatever means possible, they decided to abrogate the carefully conceived plan of developing the reservoir by working methodically up the EE-2 borehole. Instead, they carried out three increasingly large stimulation tests in EE-2, from just below the casing shoe at 3,529 meters (11,578 feet)—the only interval of the open hole that could be easily isolated without the use of either inflatable packers or another cemented-in liner. The top of this interval was isolated by both the cement behind the casing, and a high-temperature casing packer set just above the shoe. The bottom was isolated by the top of the sand plug.

2.3.1 The Massive Hydraulic Fracturing (MHF) Test

The Massive Hydraulic Fracturing (MHF) Test was the last and largest of the three stimulation tests below the 9 5/8-inch casing shoe in EE-2. In December 1983, the EE-2 borehole was further sanded up, leaving only a 21-meter (70-foot) injection interval below the casing shoe. (Some HDR staff, still convinced of the "penny-shaped-fracture" theory, thought that with a drastically shortened injection interval, a very high-pressure injection of a very large amount of fluid would finally drive a single hydraulic fracture upward to intersect the EE-3 borehole above.)

Starting on December 6th, the region previously stimulated was reinflated aseismically and then greatly enlarged. Over two and a half days, 5.6 million gallons (21,000 cubic meters [m^3]) of fluid was injected at an average surface pressure of 7,000 psi (48 MPa). The pressure and flow rate profiles for this injection are shown in Figure 18.[51] The "cloud" of induced microseismic activity resulting from this injection is shown in Figure 19.[52]

Unfortunately, one of the major axes of the ellipsoidal volume approximating the stimulated region was essentially co-linear with the trace of the EE-2 borehole, and the growth of the region toward EE-3—the direction of the minor axis—was minimal. Thus, none of the numerous joints pressure-dilated during the MHF Test intersected the EE-3 borehole above. Because the orientations of these joints were close to that of the boreholes, it turned out that EE-2 and EE-3 had been drilled in the worst possible direction for hydraulic "fracturing" to establish a connection between them. Had the managers known that the pressure-opened joints would be inclined rather than vertical, the boreholes could have been drilled vertically. This would have been easier and cheaper and would have improved the chances for a connection. The MHF test ended with a high-pressure flange failure. A large fraction of the 5.6 million gallons of injectate, now heated to near in situ temperatures, was produced uncontrollably at the wellhead. EE-2 sustained serious damage.

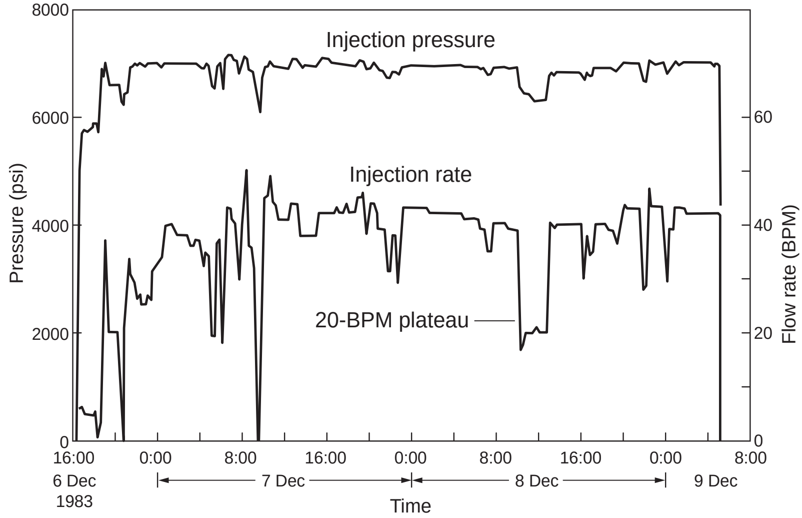


Figure 18. The surface injection rate and pressure profiles during the 2.5 days of the Massive Hydraulic Fracturing Test in EE-2

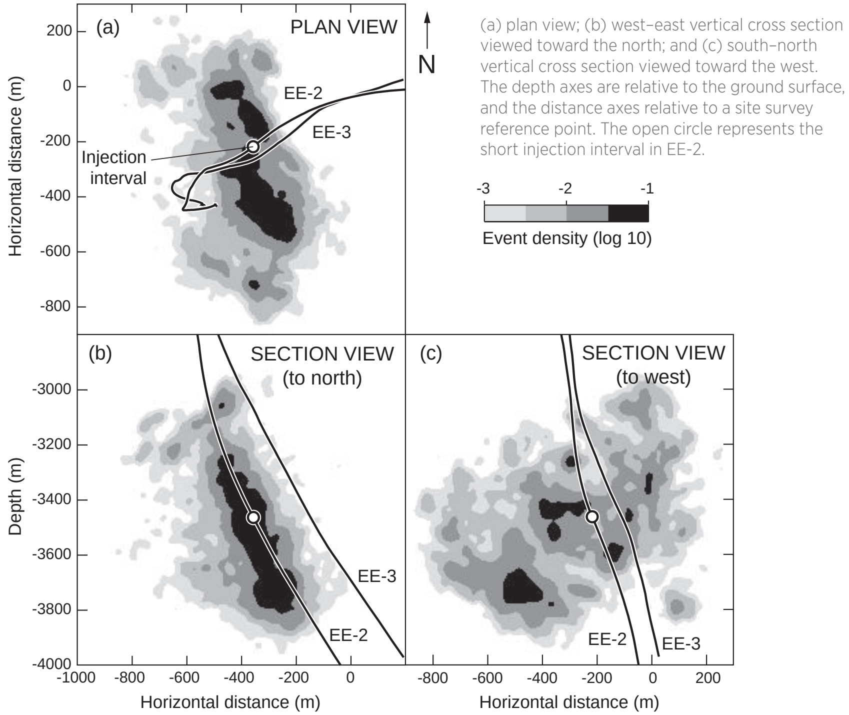


Figure 19. Density plots of microearthquakes detected by downhole seismic instruments during the injection phase of the Massive Hydraulic Fracturing Test

In May 1984, a large stimulation test was carried out in EE-3, but it too failed to connect the boreholes. Finally, from April through June of 1985, EE-3 was directionally redrilled (as EE-3A) through the seismically delineated MHF Test region. Good flow communication through the nascent Phase II reservoir was finally achieved.

2.3.2 The Initial Closed-Loop Flow Test (ICFT)

In 1985, the demonstration of flow connectivity between the redrilled EE-3A wellbore and the EE-2 reservoir zone made it clear that a viable HDR system had finally been established. The second phase of the Fenton Hill HDR Project—the deeper Phase II reservoir—took about five years (1980–1985), much longer than originally anticipated. Over that period, Germany and Japan contributed funds and manpower to the effort. The German researchers withdrew from the program at the end of 1985. In early 1986, Japanese scientists began pressing strongly for an evaluation of the thermal and flow characteristics of the deeper HDR system. (The information in this section is based mainly on the comprehensive report on the Initial Closed-Loop Flow Test (ICFT).)[53]

The only option for testing the Phase II system was to make EE-2 the production well and EE-3A the injection well. The lower part of the EE-2 wellbore, which penetrated the Phase II reservoir, had twice sustained casing damage. The first episode occurred immediately following the MHF Test in December 1983. Repair work done in the fall of 1984 restored EE-2 to usable condition, but only for low-backpressure operation as a production well. The second episode, a casing collapse in May 1985, rendered wireline logging in the lower part of the wellbore impossible. At the time, the reason for the logging problems was unknown (this further damage to the casing would not be discovered until November of 1986, 18 months later).

The ICFT took place in the late spring and early summer of 1986. Although water had previously been injected into both Phase II wells—initially during hydraulic stimulation experiments and later to prove fluid connectivity between the two wellbores—the ICFT was the first experiment specifically designed for energy production.

The ICFT, the first extended circulation test of the Phase II HDR system, was carried out with a largely *ad hoc* surface system composed of rented and temporary equipment. The test itself was plagued with operational problems that led to more than a dozen unscheduled shut-ins—most were fortunately very brief. Despite these difficulties, however, the ICFT greatly improved researchers' knowledge of the Phase II underground system, providing information critical for establishing the operating parameters for the forthcoming Long-Term Flow Test (LTFT).

In particular, seismic data from the ICFT shed light on the pressure threshold below which seismic growth of the reservoir would not be induced. This knowledge enabled the LTFT to be run from the very beginning at the highest possible aseismic injection pressure. These data also demonstrated the important role that the production well plays as a pressure sink in an HDR system, giving rise to the recognition that multiple production wells are essential if an HDR energy production facility is to operate at maximum productivity. Further, the ICFT generated data on the hydraulic, thermal, water-loss, and geochemical behavior of the Phase II reservoir that significantly advanced understanding of HDR systems, both at Fenton Hill and elsewhere.

Table 5 summarizes the reservoir performance data during the two segments of the ICFT (roughly two weeks each).

Table 5. Operating Conditions during Two Quasi-Steady-State Periods Representing the Two Segments of the Initial Closed-Loop Flow Test

Operating Conditions	Moderate-flow/ moderate- pressure period June 1-2, 1986)	High-flow/high-pressure period (June 18, 1986)
Injection		
Flow rate, gpm (L/s)	179 (11.3)	290 (18.3)
Pressure, psi (MPa)	3890 (26.8)	4570 (31.5)
Temperature, °C	18.5	16
Production		
Flow rate, gpm (L/s)	135 (8.5)	214 (13.5)
Pressure, psi, (MPa)	351 (2.4)	500 (3.4)
Temperature, °C	173	190
Rate of water loss, gpm (L/s)	44 (2.8)	76 (4.8)
Thermal power production, MW	5.6	9.8
Flow impedance, psi/gpm (MPa/L/s)	26 (2.9)	19 (2.1)

Power production is, of course, the ultimate objective of all HDR research and development work. The most significant result of the ICFT was the thermal power levels achieved: an impressive 10 MW. At the time, some argued that this level of output was not meaningful because of the high injection pressures (over 4,500 psi), which caused an undesirable expansion of the reservoir in "stagnant" regions farthest from the production well and hence the loss of a great deal of water.

Only later did it become clear that the Phase II HDR reservoir was elongated in shape, and consequently, the most efficient way to operate the HDR system would be to place a production well at each end of the reservoir. With the pressure at these two boundaries constrained by the lower-pressure regions around the production wells, reservoir growth would be greatly restricted—even at injection pressures approaching 4,600 psi.

In light of knowledge today, had a second production wellbore been in place on the far side of the reservoir, not only would reservoir growth have been prevented but output would have doubled. With two production wells, an estimated 20 MWt could have been produced from the Phase II reservoir for a significant period. (reservoir modeling suggests at least 10 years.) This is enough energy to produce several MW of electricity, even at modest thermal-to-electric conversion rates. An electric production facility of this size would be ideal for a small community or a small industrial facility. At the same time, the second production well would capture most of the water otherwise lost and would act as a "pressure-relief valve," virtually eliminating the seismic activity that characterized the high-flow/high-pressure segment. The ICFT performed in 1986 unequivocally demonstrated the technical feasibility of the HDR concept based on the significant amount of thermal power generated throughout the testing period.

As illustrated in Figure 20, the majority of seismic events were recorded during the high-pressure segment of the ICFT.[53] In fact, the few events detected during the moderate-pressure segment occurred during or shortly after the two short high-pressure excursions. These data provide strong evidence that the volume of the Phase II reservoir was stable during the moderate-flow/moderate-pressure segment of the ICFT, but the reservoir was undergoing significant growth throughout the high-flow/high-pressure segment.

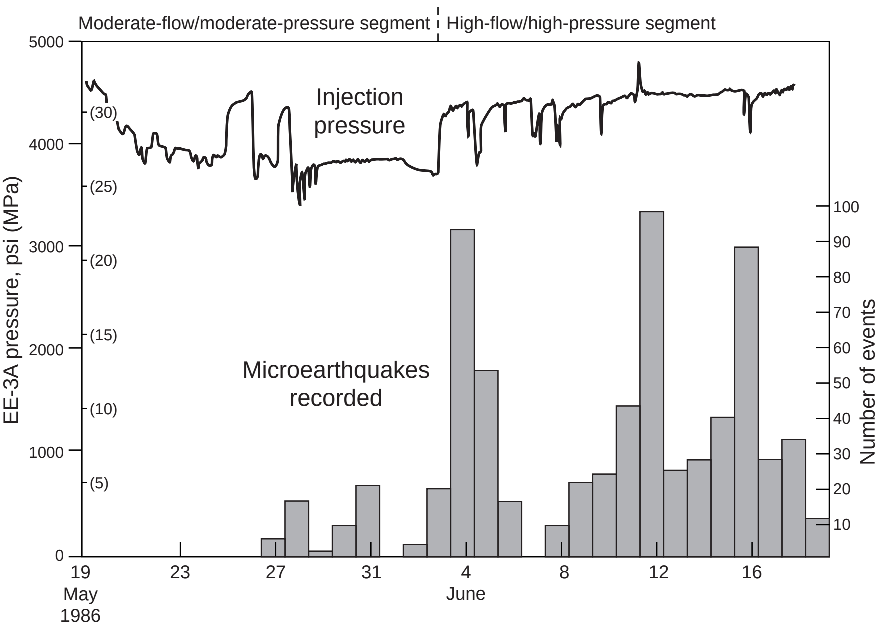


Figure 20. Correspondence between injection pressures and microearthquake occurrences over the course of the Initial Closed-Loop Flow Test

The spatial pattern of seismicity observed during the latter half of the ICFT is shown in planar view in Figure 21. It indicates that reservoir growth took place in the stagnant region beyond the injection well, on the side of the reservoir farthest from the low-pressure region surrounding the production well. Figure 21 also shows seismic events recorded during the original creation of the reservoir by the MHF Test. Whereas the events of the MHF Test are more or less symmetrical around the injection wellbore (which at the time was EE-2), those of the ICFT are highly asymmetrical. The few that are visible in the region near the injection wellbore (EE-3A) were all recorded during the shut-in at the end of the test.

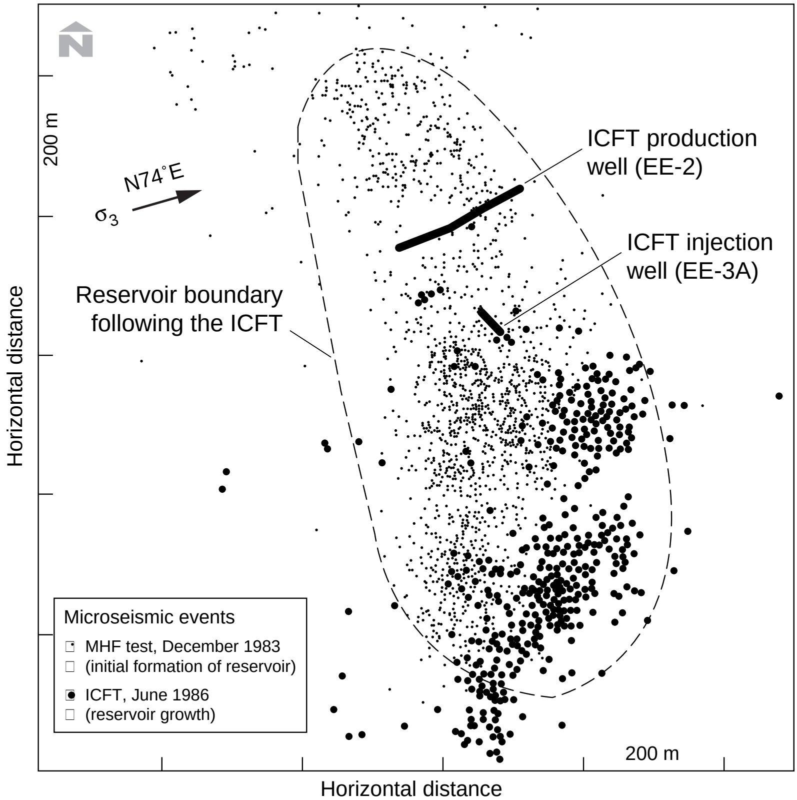


Figure 21. Distributions of seismic events during the Massive Hydraulic Fracturing test and the Initial Closed-Loop Flow Test. The direction of the least principal earth stress ($\sigma 3$) is also shown.

One objective of the LTFT was to circulate fluid through the reservoir at the highest pressure possible without causing reservoir growth. By demonstrating circulation under both aseismic and seismic conditions, the ICFT provided invaluable guidance for selecting the optimum injection conditions for the LTFT.

2.3.3 Sidetracking and Redrilling of the EE-2 Borehole

In November 1986, following the second of two failed attempts to repair the casing deep in EE-2, the decision was made to sidetrack and redrill the borehole, creating the EE-2A “leg” with a trajectory that would closely follow that of EE-2. The commercial rig already on site was retained for the redrilling and completion work. The drilling plan, modeled after that used to successfully drill EE-3A, featured 1) large-diameter (5-inch), moderate-strength drill pipe to eliminate twist-offs; 2) carefully designed bottom-hole assemblies (BHAs) and bits to improve the accuracy of directional drilling and length of bit runs; and 3) a high-temperature sepiolite/bentonite drilling fluid to keep the hole clean and increase the penetration rate.

The selected kickoff depth for sidetracking was 2,964 meters (9,725 feet), about 244 meters (800 feet) above the higher region of collapsed casing. Fieldwork began in early September 1987, with three cementing operations to plug back and completely seal off the borehole below about 3,000 meters (9,800 feet). In early October, after a window had been milled through the casing, the whipstock/packstock assembly was run in the hole on drill pipe. Sidetracking was completed three days later. By October 17, the drilled depth was 3,093 meters (10,149 feet). From October 18 to November 2, the reservoir was pressurized through EE-3A and inflated to 2,200 psi (15.2 MPa) above the hydrostatic pressure. As EE 2A penetrated the Phase II reservoir, the top of the reservoir was indicated by evidence of flowing joints (i.e., changes in flow, pH, and concentrations of carbon dioxide and other dissolved chemical species measured by mud and geochemistry logs). The top was calculated to be at a depth of 3,300 meters (10,840 feet)—a difference of just 3 meters (10 feet) from that found by temperature logging for the top of the reservoir in the vicinity of EE-3A.

On November 11, EE-2A was drilled to its final depth of 3,770 meters (12,360 feet), some 90 meters (300 feet) below the apparent bottom of the Phase II reservoir (to create a “rat hole” to collect debris that could otherwise block the lowest producing joints). Logging revealed 14 reservoir flow connections over a 366-meter (1,200-foot) interval 3,304–3,667 meters (10,840–12,030 feet), with a major set of deep, flowing joints located near 3,700 meters (12,000 feet).

From initial sidetracking, the hole was drilled to 791 meters (2,595 feet) in less than 30 days. The successful drilling fluids program contributed to the high average penetration rate—an impressive 3 meters (10 feet) per hour. Drilling proceeded two and one-half times faster than the rate at which EE-2 was originally drilled, averaging a rate of 27 meters (90 feet) per day.

In early December of 1987, the redrilling work was followed, by an experiment designed to characterize the reservoir as now accessed by EE-2A. This experiment included a seven-day flow test, tracer testing, temperature logging, gamma-ray and three-arm-caliper logs, and seismic monitoring. During the flow test, only a few seismic events were recorded. By the end of the test, at an injection rate of 2.2 BPM

(93 gpm) and an injection pressure of 3,475 psi, the water-loss rate had dropped to 22.5 gpm and was still declining by about 2 gpm per day. At this time, early in the re-inflation of the Phase II reservoir, the flow impedance was 52 psi/gpm. Along with the data from the tracer tests, these findings indicated that most of the "lost" water was actually stored within the existing reservoir rather than going into fracture extension and reservoir growth.

The completion of EE-2A was different from that of any other wellbore at Fenton Hill. The hole was cased from just above the fractured reservoir all the way to the surface (with 7-inch casing), and the casing was cemented over its entire length. The work began with multiple logging runs and televiewer surveys of the open-hole interval below the window to ensure that the hole was still in good condition. After this the production interval was covered by filling the hole with sand to 3,284 meters (10,775 feet). Then the 7-inch casing was run in the hole on drill pipe and hung off the 9 5/8-inch casing with a liner hanger, putting the bottom of the cement shoe at 3,282 meters (10,769 feet), 1.8 meters (6 feet) above the top of the sand. The new casing extended up through the window and into the 9 5/8-inch casing. The top of the polished bore receptacle (PBR) was installed just above the liner hanger, at 2,895 meters (9,499 feet). The 7-inch casing was then cemented in place.

The sidetracking, redrilling, and completion of EE-2A were a complete success. These operations represented the culmination of the Fenton Hill HDR drilling experience. They resulted in a production well that was structurally sound and provided excellent access to a number of fluid-carrying reservoir joints. This wellbore performed flawlessly during all subsequent testing of the Phase II HDR system.

EE-2A's success, along with the achievement of redrilling the EE-3 wellbore, proved that HDR drilling should no longer be viewed as high-risk and overly difficult. With good planning, sufficient lead time to order the proper equipment, and most importantly, excellent rig supervision to ensure careful judgment—especially the ability to adjust to changing conditions—a drilling project can be undertaken with only moderate risk even in a difficult, high-temperature drilling environment like Fenton Hill.

2.3.4 Extended Static Reservoir Pressurization

With the EE-2A production wellbore complete, and thus the underground portion of the Phase II HDR system ready for the LTFT, researchers turned their attention to construction of a surface plant. Because it would not be possible to carry out experiments requiring circulation through the reservoir while the surface plant was being built, an extended series of pre-LTFT pressure tests was planned to 1) assess water losses with time at various pressure levels and 2) investigate, as a function of pressure, the fluid-accessible reservoir volume. These tests were designed to use low-volume pumps and related equipment already on hand. (The information on this experiment is abstracted from references 54 and 55.)

Known as Experiment 2077, this extended static reservoir pressurization lasted from late March 1989 through December 1990.[56] With EE-2A shut in, water was injected into the EE-3A wellbore to pressurize the reservoir to a target level. Then the injection rate was reduced to maintain the pressure (± 25 psi, as measured at the EE-2A wellhead) and adjusted—by alternating pumping periods with shut-in periods—to just offset the natural water loss at that pressure. This procedure was carried out a number of times, for several different target pressures. (For this experiment, pressures were specified in integer MPa rather than psi, to accommodate the many foreign observers of this experiment.) The experiment also offered an opportunity to address the concerns voiced by the AEC, ERDA, DOE, and the Japanese and Europeans: that reservoir water losses could prove to be a severe constraint on commercialization of HDR technology.

The results of Experiment 2077 clearly showed that water losses from deep, pressure-dilated regions of hot crystalline rock can be very small. Figure 22 depicts the rate of water loss observed at a pressure of 15 MPa during the 17 months of static reservoir testing between June 1989 and October 1990. (Note: Although construction of the surface plant was going on at the same time as this experiment and created a number of difficulties in controlling pressures, the average pressure during this period was about the same as that during the four pressure plateaus: 15 MPa. Until this experiment, many observers had been convinced that no such large region of the deep earth could be maintained at a pressure level this high—5 MPa above the measured least principal earth stress—without spontaneous hydraulic fracturing and subsequent rapid pressure loss.)

Following an initial inflation period of about 14 days, during which water was being injected at a pressure of 15 MPa and stored within the body of the reservoir, the water-loss rate declined linearly with the natural logarithm of time (represented by the shaded area in Figure 22).[55] This observation implies two-dimensional diffusion (no significant water loss in the vertical direction) from the reservoir boundaries, which is consistent with the flattened ellipsoidal shape of the reservoir indicated by seismic data. During the latter part of the test period, the water-loss rate appeared to be approaching a constant value of about 2.1 gpm—suggesting that with extended pressurization, water loss transitions to spherical diffusion from a point source. Notably, by the end of the fourth pressurization at 15 MPa, the pressure on the Phase II reservoir—a volume of pressure-stimulated rock measuring close to one-third of a cubic kilometer—was being maintained by a flow less than that from a typical garden hose.

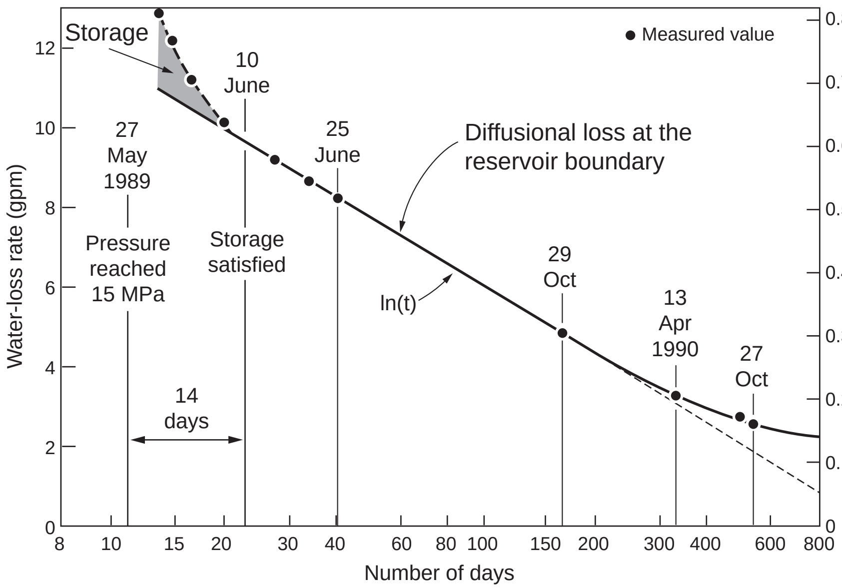


Figure 22. Water-loss rate vs. log (time) during the 15-MPa pressure plateaus of Experiment 2077.

2.3.5 The Long-Term Flow Test (LTFT—1991–1995)

LANL conducted the Long-Term Flow Test (LTFT), a series of linked flow tests, from December 1991 to July 1995. The LTFT was terminated when flow from a deep joint in the high-pressure reservoir broke through into the annulus outside the pressure string in the injection well (EE-3A), terminating the LTFT.

The LTFT program was designed to simulate as closely as possible the conditions under which a commercial HDR power plant might operate. The operating plan adopted in July of 1991 summarized the LTFT's objectives: to "bring the reservoir to the highest possible aseismic pressure and circulate water through it under steady-state conditions for as long as possible." Although the LTFT was faithful to the spirit of its operating strategy, unanticipated events imposed a number of modifications. (The following information on the LTFT was derived from several reports.)[57-60]

PRELIMINARY EXPERIMENTS

The first of three preliminary production flow tests—the first circulation of water through the Phase II reservoir in about four years—was conducted December 4–6, 1991, at an injection pressure of 3,700 psi (26 MPa), a production backpressure of 2,210 psi (15.2 MPa), and a production flow rate of 74 gpm. The thermal power production during this test was a modest 2.7 MW. This and several tests that followed exposed minor equipment problems with the surface plant, which were corrected.

THE FIRST STEADY-STATE PRODUCTION SEGMENT

The LTFT proper began April 8,1992, with the first steady-state production segment. This segment ended abruptly in late July, with the sequential failure of the two high-pressure, positive-displacement injection pumps. Inspection revealed hairline cracks in almost all of the cylinder blocks of both pumps, rendering them unusable.

In spite of its premature termination, the first steady-state test segment was extremely successful in almost every technical aspect. Perhaps the most significant technical accomplishment was that only 10 days after the start of circulation, the surface equipment was performing so well that it was possible to put the plant into an automatic, "unmanned" operational mode. However, a brief electrical power upset occurred the next evening—Sunday, April 19—provoking an automatic shutdown that resulted in 15 hours of lost production. This shutdown feature and all the other automated control and safety systems performed as designed.

After several more electrical problems, during both manned and unmanned periods, the electrical controls were redesigned to prevent random power interruptions of a few seconds or less from totally shutting the plant down. The redesign was successful: the system functioned more and more smoothly, and unmanned operations—at first over weekends and then every night as well—soon became the norm. Circulation was maintained more than 95 percent of the time, and production rates and temperatures were extremely stable. Apparently, had the injection pumps not failed, circulation could have been maintained indefinitely.

INTERIM FLOW TESTING

Over the next seven months (until February 1993)—a period referred to as Interim Flow Testing—a LANL pump followed by several rental pumps were used to continue the LTFT, maintaining the reservoir pressurization and some circulation. However, the high injection pressure (about 4,000 psi) and the continuous operation caused almost all of these pumps to ultimately fail. The exception was the final rental pump procured from the REDA Pump Company. Installed on January 25, 1993, the REDA pump was fundamentally different in design from the failed injection pumps. The pump was centrifugal rather than piston, and powered by electricity rather than diesel fuel. Although it had a narrower operating range than the piston pumps and was more expensive to run because of the electric drive, the REDA pump proved to be simpler to operate and maintain.

THE SECOND STEADY-STATE PRODUCTION SEGMENT

Because the reservoir had been maintained under pressure during the almost seven months from the beginning of the first steady-state segment, similar operating conditions were rapidly reestablished when the second segment began on February 22, 1993. The only problem encountered during this test segment was related to the REDA pump's greater electric power requirements. In late March, REDA was called in, the system was shut in for 44 hours, and larger underground electric cables and auxiliary components were installed. Operations resumed until May 17, when the wells were shut in.

Even though continuous circulation under the desired conditions was achieved for only 55 days, the second steady-state production segment demonstrated that even after many months of intermittent operation, an HDR system could be rapidly returned to steady-state conditions provided the reservoir had been kept pressurized.

THE THIRD STEADY-STATE PRODUCTION SEGMENT

Following a yearlong (May 17, 1993 – May 9, 1995) circulation shutdown during which a number of experiments were carried out, the third steady-state production segment began on May 10, 1995. Known as the Reservoir Verification Flow Test (RVFT), this stage was designed to 1) verify whether the system could be brought back to the operating conditions extant at the end of the preceding production segment and 2) collect circulation data that would be important for the industry-led HDR project then being envisioned.

First, fluid was injected into the reservoir for a few days, to increase the pressure. Then full circulation was begun. A new REDA pump, with 218 rather than 200 centrifugal stages, was purchased for the RVFT. To minimize costs, a diesel engine was scavenged from one of the defunct reciprocal injection pumps to power the new pump. The RVFT comprised four operational stages.

Stages 1–3: Return to Steady-State Operation after a Two-Year Hiatus

Over the 35 days of the first stage, operating conditions essentially identical to those of the first two steady-state production segments were gradually re-established. The RVTF's second stage began on June 14 1995. In this stage, the backpressure of the production well was increased from 1,400 to 2,200 psi (9.5 to 15.2 MPa). On June 23, the third stage began. The production well was shut in for 25 minutes every morning for six days, while all other operating parameters remained unchanged.

Stage 4: Using an HDR Reservoir for Load-Following

A significant experiment was conducted as the last part of the RVFT in July 1995. It demonstrated a concept referred to as "load-following," whereby an HDR reservoir can be operated for several hours each day with greatly increased thermal power production.[61-62] This experiment, designed to induce and temporarily sustain a large increase in the production flow rate, generated the most important data of the third steady-state production segment.

For six days, while the injection pressure was held steady at 3,960 psi (27.3 MPa), a 20-hour period of high-backpressure (2,200 psi [15 MPa]) operation was alternated with a 4-hour period of greatly increased production flow (maintained through a controlled decrease in the backpressure—to a final value of 500 psi). The last two of the six 24-hour cycles are shown in Figure 23.[61]

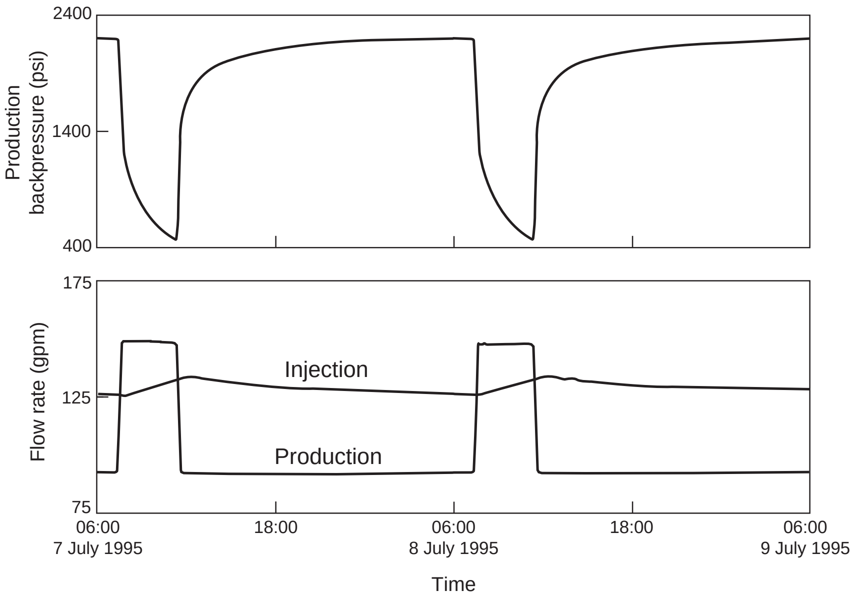


Figure 23. Injection and production flow profiles vs. the controlled variation in the production well backpressure during the last two daily cycles of the Load-Following Experiment

During the 4-hour portion of the daily cycle, the production flow rate was increased by a constant 60 percent. With the associated 10°C (50°F) increase in the production fluid temperature, the overall power level achieved was 65 percent higher than that of the preceding 20-hour period of steady-state operation.

As shown in Figure 23, for each cycle the production well backpressure began at 2,200 psi and ended at 500 psi. However, to maximize reservoir power production during the 4-hour portion of the cycle, the backpressure for the 20-hour portion could have been increased somewhat (e.g., to 2,400 psi) and the final pressure could have been dropped to near 182 psi (the saturation pressure for water at 190°C [374°F]). These operational changes would have increased the power multiplier for the 4-hour period of enhanced production from 1.65 to closer to 2.0—a considerable improvement.

When an HDR reservoir is used in this advanced operational mode, the principle of "pumped storage," (i.e., the storage of additional pressurized fluid within the reservoir) can be engaged. In essence, during the Load-Following Experiment at Fenton Hill, a portion of the high-pressure reservoir fluid stored near the production well was vented down (temporarily reduced) during the 4 hours. Then, during the next 20-hour period of steady-state operation at a backpressure of 2,200 psi, the reservoir was re-inflated by injection at a somewhat higher rate. (The rate gradually returning to its previous steady-state level during the subsequent 20-hour period).[63]

The demonstrated ability of HDR geothermal systems, operating in a base-load mode, to provide peaking power upon demand confers an additional cost advantage on HDR power plants that has not been considered in any of the HDR economic studies. The premium for peaking power is typically more than twice the base-load price. For example, for a base-load busbar price of 9 cents/kWh and a peaking price of 21 cents/kWh for 4 hours, the overall effective price would be 11 cents/kWh—a premium of 2 cents/kWh, which could markedly change the profitability of an HDR power plant.

The pumped storage aspect of this experiment was not particularly emphasized at the time. The Fenton Hill experiments suggested that upon re-inflation, the region surrounding the production well behaves like an elastic spring, storing pressurized fluid for delivery the following day. The recent growth of wind power (often generated at night) presents an appealing opportunity for exploiting this aspect. Excess wind power could be used to power an additional injection pump during all or a portion of the 20-hour re-inflation phase—the supplemental store of pressurized fluid thus created turning the HDR reservoir into a kind of "earth battery." A portion of this excess pressurized fluid could be recovered the next day in the form of increased power generation for peak demand periods. In other words, the reservoir could be hyper-inflated to a mean pressure level above that used for steady-state operation thereby enabling a greater quantity of pressurized fluid to be stored during the off-peak hours. The quantity would be limited only by the requirement to keep the pressure below a level that would cause renewed—or excessive—reservoir growth.

RESULTS OF THE LTFT

HDR Viability Demonstrated, Lessons Learned

The LTFT program lasted 39 months, of which more than 27 were downtime—most of that accounted for by the two years of nonoperation (1993–1995). In all, the system was operated in a circulation mode for a little over 11 months. Even so, the results obtained from these limited operations achieved the project's primary goal: to demonstrate the viability of HDR technology for reliable and predictable sustained energy production. The tests also provided valuable information with respect to secondary objectives, such as maximizing the energy output of an HDR system and understanding its performance.

Specific lessons learned from the ICFT were applied during the LTFT, with a few variations:

- The flow rate was typically maintained at 87–103 gpm (5.5–6.5 L/s)—much lower than the rate of 200–250 gpm (12.6–15.8 L/s) recommended after the ICFT (the higher flow rates simply were not possible during the LTFT without inducing seismicity).
- The number of injection zones was not increased (at that point in the Fenton Hill Project, further reservoir stimulation did not prove practical).

Table 6 shows representative data from a number of production periods during which the operating conditions simulated those of a commercial HDR power plant.

Table 6. Long-Term Flow Test Operating Data

	First Steady-State Production Segment (7/92)	Second Steady-State Production Segment (4/93)	Third Steady-State Production Segment (RVFT)			
			Stage 1 (6/95)	Stage 2 (6/95)	Stage 3 (6/95)	Stage 4 (7/95)
Injection						
Pressure, psi (MPa)	3960 (27.3)	3960 (27.3)	3960 (27.3)	3960 (27.3)	3960 (27.3)	3960 (27.3)
Flow rate, gpm (L/s)	106 (6.7)	103 (6.5)	127 (8.0)	120 (7.6)	124 (7.8)	128[a] (8.1)
Production						
Backpressure, psi (MPa)	1400 (9.7)	1400 (9.7)	1400 (9.7)	2200 (15.2)	2200 (15.2)	2200-500 (15.2-3.4)
Flow rate, gpm (L/s)	90 (5.7)	90 (5.7)	105 (6.6)	94 (5.9)	98 (6.2)	92-150 (5.8-9.3)
Temperature, °C	183 (361)	184 (363)	184 (363)	181 (358)	183 (361)	183-189 (361-371)
Net Water Loss[b]						
Rate, gpm (L/s)	12.5 (0.8)	6.8 (0.4)	18 (1.1)	21 (1.3)	18 (1.1)	c
% of injected volume	12	7	14	18	15	---

a Average value.
b Net water loss after taking into account injected water returned to the surface via the annulus leak in the injection wellbore.
c Water loss data were meaningless during these test segments.

Tracer Tests and Geochemical Analyses

Figure 24 shows normalized recovery profiles for three fluorescein tracer tests conducted during the first and second steady-state production segments and just before the two-year shutdown that began in May 1993.[58] The figure also shows a recovery profile for a p-TSA tracer test that was conducted concurrently with the first fluorescein test, which confirms the one obtained via fluorescein.

As circulation proceeded, the tracer took progressively longer to traverse the reservoir. The increasing time for the tracer's first arrival at the production well showed that as time went on, the shorter flow paths were being closed off. The later peaks and broader shapes of the 1993 curves generally indicate that the modal and dispersion volumes were growing. These data leave no doubt that the HDR reservoir at Fenton Hill was a dynamic entity—that under conditions of steady-state circulation, the volume of hot reservoir rock accessible to the circulating fluids continually increased.

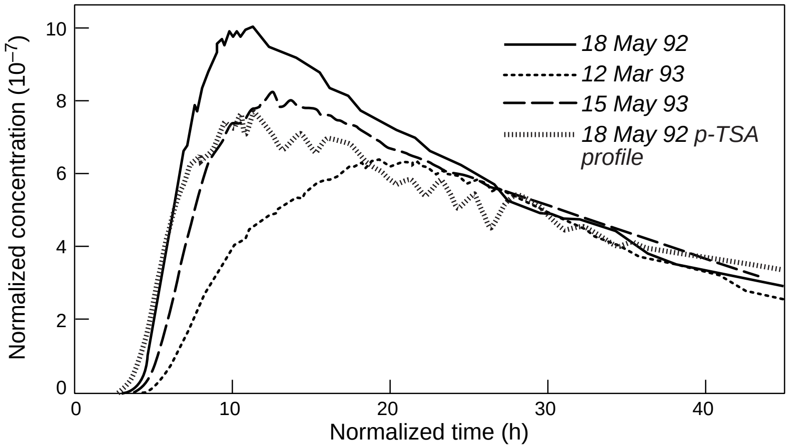


Figure 24. Tracer recovery profiles (three fluorescein and one p-TSA) during steady-state operation (1992–1993)

Further tracer testing in June and July of 1995 showed a clear decline in fluorescein recovery over the intervening month. The most reasonable explanation was a difference in temperature. The average temperatures the tracer encountered as it traversed the reservoir in July were higher than in June. This finding suggests—as do a number of others—that as circulation of fluid in an HDR reservoir continues, access to hot rock improves.

In sum, the results of the LTFT tracer tests and geochemical analyses led to the following conclusions:

- The reservoir is dynamic in nature. Changes in tracer return profiles from one test to another indicated that flow paths were continually changing.
- As the redistribution of flow paths proceeded, the fluid was continually accessing new, hot rock, extending the useful lifetime of the resource.
- The geochemistry of the circulating water rapidly reached equilibrium. In reservoirs created in hard crystalline rock, such as the one at Fenton Hill, the water can be expected to have total salinity levels well below that of seawater and therefore be relatively noncorrosive.

The LTFT was the culmination of the Fenton Hill HDR Project. Although the technical goal of continuous production of energy for a full year was not achieved, the maintenance of circulation for a total of more than 11 months demonstrated that energy could routinely be extracted from an HDR reservoir over an extended time period. Moreover, the intermittent shut downs provided an unanticipated opportunity to evaluate the response of the HDR system under a variety of adverse circumstances that might reasonably be encountered during operation of a commercial HDR energy plant. Most notably, the researchers clearly demonstrated that the system could be rapidly brought back on line after long periods of nonproduction, regardless of whether reservoir pressure had been maintained in the interim.

The LTFT also showed that cyclic production schedules could be employed to enhance productivity. With a couple of early tests providing the groundwork, straightforward cyclic production strategies implemented during the final stages of the LTFT provided unambiguous evidence of the advantages of this technique, from both operational and marketing standpoints. Finally, the LTFT produced a wealth of HDR experimental data that can be used to improve models to simulate HDR systems.

2.4 Findings and Conclusions

The principal accomplishment of the Fenton Hill HDR Project was the creation and flow testing (approximately one year each) of two separate, fully engineered reservoirs, each completely independent from one another. Because they were confined, the induced seismicity was localized within the pressure-dilated reservoir regions. Of the many thousands of recorded events, the largest was about magnitude 1.0 on the Richter scale.

The project showed that directional drilling control was possible in hard crystalline rock, and that hydraulic-pressurization methods could create permanently open networks of joints in large enough volumes of rock (over 1 km3) to sustain energy extraction. The jointed volume could be intersected by drilling into the mapped region. Connections between the wells could be established and fluids circulated at useful temperatures for extended time periods.

The high pressures needed to keep the Phase II joints open caused operational problems and required substantial amounts of power. At greater depths with temperatures over 300°C (570°F), wells could still be drilled, pre-existing joints still opened through hydraulic stimulation, and the stimulated volume mapped. The reservoir fluid could be circulated in such a manner that the stimulated volume did not continue to grow and, thus, water losses were minimized. However, if injection pressures were lowered to reduce water loss and reservoir growth, the flow rates were lower than desired for power production. If water was injected at high enough pressures to maintain high flow rates, the reservoir grew and water losses were high. Based on the injected fluid volume, the joint patterns that were observed did not match those predicted by early modeling.

Models of flow and heat transfer were developed, and with data collected during testing, could be used to predict the behavior of the HDR reservoir. The thermal–hydraulic performance of the recirculating Phase I system was successfully modeled, and indicated approximately 10,000 m^2 of effective surface area when matched to field data. This area is too small by about a factor of 100 for a commercial-scale system. The Phase II reservoir was about 100 times larger than the Phase I reservoir, and showed no cooldown in the production temperature after 11 months of circulation.

The Fenton Hill Project brought the potential for HDR to become a major source of economical energy for the 21^{st} century closer to reality.

3.0 Geopressured-Geothermal Energy Program

3.1 Background

"Geopressured-geothermal" reservoirs are subsurface reservoirs which contain hot pressurized brine saturated with dissolved methane at the pressure, temperature, and salinity of the reservoir formation. Geopressured reservoirs can potentially provide three sources of energy: 1) chemical energy in the form of dissolved methane, 2) thermal energy from the hot (temperature over 93°C [200°F]) brines, and 3) mechanical energy from high brine flow rates (over 20,000 barrels per day) and high well head pressures. Geopressured resources occur throughout the United States but most prominently along the northern Gulf of Mexico basin and the Pacific West coast (Figure 25).[64] Estimates of the energy potential of geopressured-geothermal resources range as high as 160,000 quads.[64-66]

Figure 25. Location of geopressured basins in the United States

The DOE's Geopressured-Geothermal Energy program ran from the mid 1970s to the early 1990s. The program was intended to evaluate the extent and viability of geopressured-geothermal resource development using test data from both new and existing wells. The main goals of the Geopressured-Geothermal Energy program[67] were to:

- Define the extent of the geopressured reservoirs in the Gulf Coast states of Texas and Louisiana;
- Determine the technical feasibility of reservoir development including downhole, surface, and disposal technologies;
- Establish the economics of production;
- Identify and mitigate adverse environmental impacts;
- Identify and resolve legal and institutional barriers; and
- Determine the viability of commercial exploitation.

The research program involved the private and public sector including Louisiana State University, University of Texas at Austin, S-Cubed, Institute of Gas Technology, University of Southwestern Louisiana, Lawrence Berkeley National Laboratory, and Idaho National Laboratory. Several historically Black colleges and universities also participated actively in the program.

DOE chose to focus on northern coastal areas of the Gulf of Mexico where extensive information was available from hydrocarbon exploration and production. By the mid 1970s, the structure and geologic history of the northern Gulf of Mexico basin was well documented.[68-69] Broad fairways of abnormally pressured Cenozoic sedimentary formations at approximately 3,000 meters (10,000 feet) below the surface with temperatures over 107°C (225°F) contained the greatest potential for geopressured-geothermal energy.

The fairways are defined by regional geology, well log data, well production information, and seismic surveys where available. The geopressured resource zones resulted from rapid and extensive deposition of sediment accompanied by subsidence and growth faulting. As the sediment depocenters moved outward into the Gulf, younger deltaic sediment covered the older sediments to form deposits that gradually thickened gulfward. The heavy younger sands sank into the less dense shaley sediments to form growth faults and sealing water in the sand formations. With increasing depth and sediment load, temperature and fluid pressure increased accompanied by chemical diagenesis which led to the development of geopressured corridors.

Research first suggested in the late 1960s that the heat and pressure of saline fluids from these formations might be used to process heat or power generation, and the methane might be exploited as a third energy source.[70] Twenty years later, it was estimated that about 250 trillion cubic feet (Tcf) of gas on average could potentially be extracted from the resources in this area[71]—equivalent to about 137 percent of the then known conventional methane reserves in the United States. Through a coordinated program of well drilling and testing,[72] DOE attempted to gather sufficiently reliable information for resource definition and characterization and to provide answers to questions regarding engineering, economic, and environmental issues.

The well testing program consisted of 1) Wells of Opportunity and 2) Design Wells. Wells of Opportunity were industry-drilled exploration wells that proved uneconomic for hydrocarbon production, but they were known to have penetrated geopressured reservoirs. These wells were made available to DOE for the price of plugging and abandonment. Wells of Opportunity were used only for short-term testing (typically less than a month), mostly to determine fluid properties and reservoir characteristics. Design Wells were drilled with DOE funding on sites in potentially favorable geopressured-geothermal prospects (as determined by the best available geological and geophysical data). Design Wells were subjected to long-term testing to demonstrate the feasibility of geopressured-geothermal resource exploitation. As part of the Design Well Program, shallow, non-geopressured injection wells were drilled to dispose of produced brines. Figure 26 shows the locations of both Wells of Opportunity and Design Wells.[67]

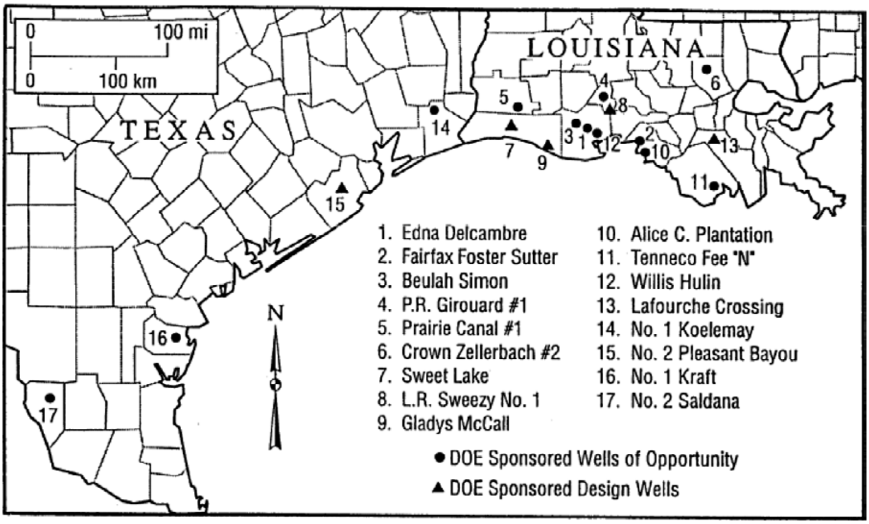


Figure 26. Location of wells investigated as part of the U.S. Department of Energy geopressured-geothermal research program in the Gulf Coast

3.2 Wells of Opportunity

Wells of Opportunity helped to characterize resources and delineate the optimum prospect areas for drilling and testing geopressured-geothermal fairways in south Louisiana and the Texas Gulf Coast. The program integrated acquired geologic and well data to define resource potential. The data included subsurface structures, potential reservoir volume and extent, temperature, pressure, porosity, permeability, gas content, gas composition, and salinity.[67/69] Much of the information and knowledge acquired was used to help identify potential targets for the Design Wells. Table 7[67] summarizes the important test results.

Table 7. Summary of Pertinent Test Results for Geopressured Geothermal Test Wells of Opportunity

Well Name	Depth (m)	Pressure (MPa)	Temp (°C)	Salinity (ppm TDS)	Gas/Brine Ratio (SCF/STB)	Flow Rate (BPD)	Methane (mol%)	CO_2 (mol%)	Other Gases (mol%)	Porosity (%)	Perm (mD)
Delcambre 3sd	-3,922	75.9	114	133,300	24.0	10,333	92.8	1.1	6.1	26.0	44.0
Delcambre 1sd	-3,832	74.9	112	113,000	24.0	12,653	95.4	2.0	2.6	29.0	364.0
F.F. Sutter	-4,810	84.3	132	190,904	24.9	7,747	89.6	7.9	2.5	19.3	14.3
Buelah Simon	-4,487	89.7	130	103,925	24.0	11,000	88.9	7.7	3.4	17.4	11.6
P.R.Giroud	-4.494	91.0	134	23,500	44.5	15,000	91.3	6.0	2.7	26.0	220.0
P.Canal	-4,565	89.2	146	43,400	47.0	7,100	88.4	8.4	3.2	22.5	90.0
C.Zellerbach	-5,096	69.9	166	31,700	55.7	3,887	71.0	23.5	5.5	17.0	14.1
Hulin #1	-6,567	127.6	182	195,000	34.0	15,000	93.0	4.0	3.0	-	13.0
Riddle Saldana #2	-2,970	45.7	149	12,800	41.0	1,950	75.0	21.4	3.8	20.0	7.0
Lear Koelemay #1	-3,533	65.2	127	15,000	35.0	3.200	81.4	13.4	5.2	26.0	85.0
Ross Kraft #1	-3,886	75.7	128	23,000	45.0	-	-	-	-	23.0	39.0

ppm TDS: parts per million Total Dissolved Solids; SCF/STB: Standard cubic feet/Standard barrel; BPD: barrels per day; mol%: Moles solute/100 moles of solution; mD: Millidarcy

Additional findings from the geopressured-geothermal resource characterization[67] included:

1. In general, the depth to the operational top of geopressure was shallower along the Texas Gulf coast (2,150-3,690 meters [7050-12,100 feet]), becoming deeper than to the northeast in Louisiana (2,765-5,530 meters [9,070-18,140 feet]).
2. Porosity generally decreased uniformly with depth. Local variations occurred related to sand composition, burial history, and formation fluid chemistry.

3. The top of geopressured zones tended to be controlled by lithology. However, plots of bottom-hole temperatures provided subsurface temperature with depth in the geopressured-geothermal fairways. This indicated that the 100°C (212°F) isotherm was at 2,460 meters (8,000 feet), and that isotherms may not respond locally to lithological changes in the same way, as does the top of the geopressured zones.

4. In general, salinity increased with depth and was highest in the zone above the geopressured zone. Salinities in hydrocarbon producing zones were high and variable (less than 20,000–100,000 ppm). Factors influencing salinity included porosity, permeability, faults, aquifer size, presence of salt, fluid movement, and burial history. The effects of these factors on reservoir salinity were poorly understood.

3.2.1 Hulin Well

The Willis Hulin No. 1 well was the deepest, hottest, and highest pressure Well of Opportunity. (The following discussion comes from reference 67 unless otherwise noted.) The well was drilled by Superior Oil Company in 1978, reaching a total depth of 6,568 meters (21,548 feet) and a maximum logged temperature of 170°C (338°F). A 183 meter- (600-foot) thick geopressured-geothermal sand aquifer between 6,126 to 6,309 meters (20,098 to 20,698 feet) was identified. After 19 months of declining gas production by Superior, the well was turned over to DOE and tested for geopressured zones above the gas production zone. Eaton Operating Company was contracted to clean and recomplete the well. Recompletion was accomplished in February 1989, and the well was plugged back about 632 meters (2,073 feet) from well bottom, to a total depth just below the geopressured-geothermal aquifer. During workover operations logs were run but two of the tools collapsed at pressures of 121 MPa due to long exposure to high temperatures, despite having a pressure rating of 152 MPa. As a result only partial density, neutron, gamma ray, and caliper electric logs were obtained.

The Hulin well was located in a fault block approximately 20 kilometers (12 miles) long (east-west) and 8.3 kilometers (5.1 miles) wide (north-south) and bounded by large arcuate faults with smaller faults within the block. A structure map derived from proprietary seismic data acquired by the Louisiana Geological Survey (Louisiana State University), led to an estimate of 1 billion barrels of brine reserves in the Hulin test reservoir. Prior estimates of 14 billion barrels of reserves were based on earlier structural models derived from data higher in the section. However, the impact of factors was difficult to accurately quantify. Such factors included lack of fault closure on the west side, lateral and vertical stratigraphic relationships between adjoining reservoirs, fluid communication among reservoirs, induced faulting due to high volumes of brine production, and so forth. These factors point to the difficulty in making accurate reservoir estimates of brine volume.

The first short-term flow tests of the Hulin well were conducted on perforated sections of the lowermost sand interval. Bottom-hole pressures and temperatures were measured and samples collected for determining fluid chemistry, gas chemistry, and gas saturation. Analysis of bottom-hole pressures indicated a reservoir permeability of 13 millidarcys (md). The lateral extent of the reservoir was not determined, although flow data suggested a fault approximately 30 to 60 meters (100 to 200 feet) from the well. A skin factor of 15 was found for the entire perforated interval (about 24 meters [79 feet]), indicating low efficiency for the perforations. Decreasing static bottom-hole pressures prior to each test suggested that the tested sand member was of limited extent and volume.

In a second series of flow tests, the upper sand member in the zone of interest was perforated and commingled with flow from the lower sand units. Bottom-hole pressures and reservoir characteristics were not determined. But substantially lower drawdown for the commingled zones suggested either higher permeability or lower skin effects. Problems with hydrate formation in the wellhead and near surface tubing was controlled by pumping diesel fuel into the well after each flow period, displacing brine in the wellbore down to a point where higher temperatures prevented hydrate stability. Potential problems with calcium carbonate scaling in the brine lines were avoided by conducting flow tests at pressures and flow rates where scale would not be expected to form. Total production during the December 1989 through January 1990 testing of the well was 16,805 barrels of brine and 536,700 scf of gas. Well and reservoir attributes are summarized in Table 7.

The Hulin well provided an example of the feasibility of using a reworked oil or gas well for geopressured-geothermal production. Well depth and tubing size were the limiting factors in production efficiency, with estimated production rates of only 15,000-18,000 barrels per day (bpd). Similar well bore limitations were typical for other depleted wells that were recompleted for geopressured-geothermal production. As a result, high (40,000 bpd) production rates from existing reworked wells could not be assumed even with excellent reservoir conditions.[73]

3.3 Design Wells

The Design Wells program was conducted to evaluate the feasibility of production from geopressured-geothermal zones for wells specifically drilled for this purpose. The program provided detailed information relevant to the key program goals. Specifically, the Design Wells were drilled and completed to obtain accurate, reliable and long-term information on the following:

1. Physical characteristics of geopressured-geothermal reservoirs (porosity, permeability, reservoir extent, degree of compaction, rock composition and shale dewatering).
2. Aquifer fluid properties (in situ temperature, chemical composition, hydrocarbon content and pressure).

3. Behavior of fluid and reservoir under conditions of fluid production at moderate and high rates.
4. Evaluation of completion techniques and production strategies for geopressured-geothermal wells.
5. Analysis of long-term environmental effects of extensive commercial application of geopressured-geothermal energy.
6. Determination of reservoir limits or boundaries.
7. Long-term scaling and corrosion prevention and development of scale inhibition procedures.
8. Long-term disposal well performance (ability to accept large volumes of spent brine over ling time spans).
9. Drive mechanisms for reservoirs.
10. The ability, with current technology, to locate and evaluate geopressured-geothermal resources.
11. Test procedure to accurately predict long-term production capability.
12. Source and flow mechanisms for co-produced liquid hydrocarbons and methane.
13. Effective surface fluid handling facilities (pumps, separators, valves, compressors, etc.).
14. Appropriate material specifications, equipment specifications, and maintenance procedures necessary to maintain long-term production with minimum down time.
15. Hybrid conversion technology, with the goal of obtaining thermal efficiency at least 20 percent greater than that from separate combustion and geothermal power cycles.
16. Economic feasibility of energy production from geopressured geothermal resources.

Design Wells were sited using information gained from Wells of Opportunity in conjunction with data from hydrocarbon exploration and production. Geopressured-geothermal prospects were identified, characterized, and if favorable, drilled for resource and reservoir testing. Five sites were identified—four in Louisiana and one in Texas. The sites in Louisiana were: 1) Lafourche Crossing (upper to middle Miocene sands), 2) Amoco Fee-Sweet Lake A (Louisiana Frio Formation, Oligocene-Miocene sands), 3) Parcperdue-L.R. Sweezy #1 (Anahuac and Frio Formations, upper and middle Oligocene sands), and 4) Gladys McCall #1 (Fleming Formation, lower Miocene sands). The lone site in Texas was Pleasant Bayou Well #2 (Frio Formation, upper Oligocene and Tertiary sands) (see Figure 26). More wells were chosen in Louisiana because of the perception that geopressured brines in the eastern Gulf would be less saline and contain greater amounts of dissolved methane.

A summary of the reservoir characteristics for the drilled Design Wells and pertinent test results are shown in Table 8.[67] In general, the Design Wells were successful in acquiring the information listed above and much was learned about the characteristics of geopressured-geothermal resources and the feasibility of sustainable production. For instance, the well testing and pressure analyses yielded reliable aquifer descriptions. An important insight was gained in regard to the predominant influence of rock compressibility on aquifer fluid displacement and ultimate recovery. In geopressured systems experiencing a high degree of pore volume relaxation (compaction), viable production rates could not be sustained once pressure depletion fell below hydrostatic. However, many problems were also encountered and some were serious enough to lead to the termination of testing in several wells either for physical and/or financial reasons.

Table 8. Summary of Pertinent Test Results for Geopressured Geothermal Test Design Wells

Well Name	Depth (m)	Pressure (MPa)	Temp (ºC)	Salinity (ppm TDS)	Gas/Brine Ratio (SCF/STB)	Flow Rate (BPD)	Methane (mol%)	CO_2 (mol%)	Other Gases (mol%)	Porosity (%)	Perm (mD)
Amoco Fee-Sweet lake A	-4,690	82.6	148	160,000	34.0	34,000	88.7	8.6	2.6	20.0	400.0
Parcperdue–L.R. Sweezy #1	-4,083	78.7	114	99,700	30.0	10,000	94.0	2.5	3.5	29.4	500.0
Gladys McCall A	-4,727	89.2	148	95,500	30.4	36,500	86.9	9.5	3.6	24.0	90.0
Gladys McCall C	-4,620	88.4	142	94,000	30.4	36,000	85.9	10.6	3.5	22.0	130.0
Pleasant Bayou Well #2	-5,019	67.6	150	127,000	24.0	25,000	85.0	10.0	5.0	19.0	200.0

ppm TDS: parts per million Total Dissolved Solids; SCF/STB: Standard cubic feet/Standard barrel; BPD: barrels per day; mol%: Moles solute/100 moles of solution; mD: Millidarcy

During production testing, two of the most significant problems encountered were the production of fine grained sand, sometimes in large slugs at high production rates, and an inability to sustain high brine injection rates in disposal wells. Other problems encountered included: limited extent of the accessible resource, due either to unexpected boundary faults or complicated permeability structure; rapid pressure decline during production tests; and catastrophic sanding of surface equipment. Nevertheless, several long-term production tests were successfully conducted. Brief descriptions of the more significant findings and tests follow with a focus on the Pleasant Bayou #2 and the Gladys McCall #1 Design Wells.

3.3.1 Pleasant Bayou—Hybrid Geopressured-Geothermal Power Plant

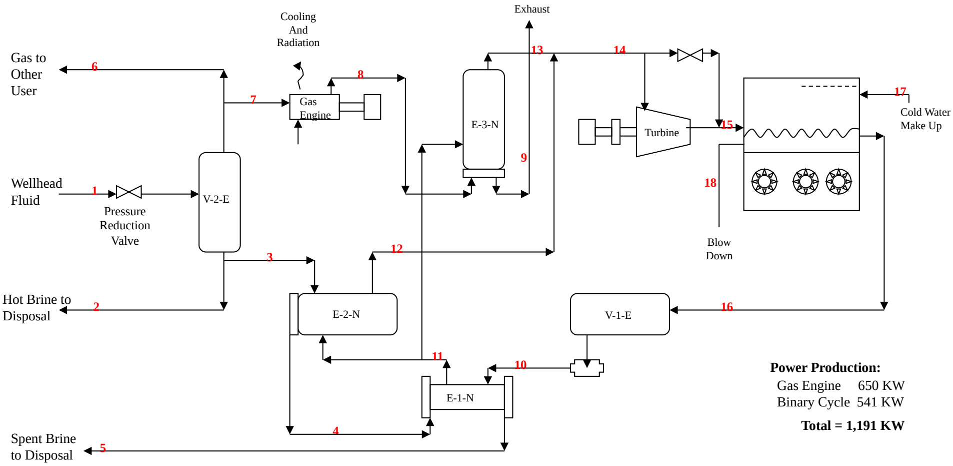
The first Design Well, Pleasant Bayou #2 in Brazoria County, Texas, was significant in that an end use application of geopressured-geothermal energy was successfully tested. In 1989, DOE and the Electric Power Research Institute (EPRI) co-funded the demonstration of a hybrid power-plant concept at the Pleasant Bayou test facility. The plant was designed, built, and operated by the Ben Holt Company. Eaton Operating Company, Inc. did the well-related work and the Institute of Gas Technology (IGT) handled the wellhead fluids upstream of the power plant.

A hybrid system takes advantage of the fact that geopressured resources contain energy in three forms: hydraulic (high-pressured fluids), thermal (heated brine), and chemical (dissolved natural gas). Previous studies had shown that hybrid cycles, using a combination of the energy sources, could yield up to 30 percent more power than stand-alone geothermal and fossil power plants operating on the same resource. In a typical hybrid conversion system, the high-pressure fluid at the well head is expanded through a pressure reduction turbine which drives an electrical generator. As fluid pressure drops, the methane gas in the brine comes out of solution. The gas is separated from the brine and either sold as natural gas or burned in a gas engine to produce electrical power. The hot, liquid brine leaving the gas separator is used in a conventional geothermal binary-cycle plant before being injected. In this hybrid cycle, the hot exhaust gas from the gas engine was used to supplement the heat content of the brine, improving the efficiency of the binary cycle.

The Pleasant Bayou power plant (Figure 27) was the first-of-a-kind demonstration of the geopressured hybrid cycle concept. Construction began in early 1989, brine and isobutane circulation began in September 1989, and the turbine and gas engines were started for the first time in October 1989. A "typical hybrid system" (as described above) was installed at Pleasant Bayou, except that valves were used in lieu of a hydraulic turbine to reduce fluid pressures at the wellhead. From October 1989 to the end of May 1990, the plant ran at or near design output, except for an occasional outage; the plant was shut down a month early because the brine injection well required rework.

The Pleasant Bayou plant produced about 1 MW of power from 10,000 barrels per day of 143°C (290°F) brine that contained 22 standard cubic foot (scf) of gas per barrel. The gas engine generated a little more than half of the total power (650 kW); the binary-cycle turbine generated the rest (541 kW). Actual parasitic loads amounted to 20 to 30 percent of total output (260-306 kW), slightly higher than the designed values of 209 kW.

Prior to its use for the power plant, the Pleasant Bayou design well was produced extensively to test the geopressured reservoir. Those tests led to problems with carbonate scale deposition in the production tubing and surface equipment, eventually resulting in failure of the well. Substantial rework, including a new production liner, was required to bring the well online. This failure led to the development of scale inhibitors and inhibition protocols. Testing showed that these scaling inhibitors and the protocols for their deployment effectively minimized the precipitation of solids on component surfaces exposed to the brines. Corrosion was not an issue. The only significant power plant problem was excessive “fouling” in the exhaust gas heat exchanger due to deposition of carbon soot. However, this was considered a relatively minor problem that could be resolved at low cost.



STREAM #	1	2	3	4	5	6	7	8	9
Fluid	Brine+Gas	Brine	Brine	Brine	Brine	Gas	Gas	Exhaust	Exhaust
Flow MLbs/Hr	341	170	170	170	170	0.47	0.47	6.6	6.6
BPD (SCFM)		10,000	10,000	10,000	10,000	(153)	(153)		
Temp °C	146	137	137	104	73	137	137	610	149
Press (PSIA)	1,500	595	595	570	528	595	595	16	15
Density /CF		64.4	64.4	66.5	68.5	1.5	1.5	0.024	0.054
STREAM #	10	11	12	13	14	15	16	17	18
Fluid	Isobutane	Isobutane	Isobutane	Isobutane	Isobutane	Isobutane	Isobutane	CW Makeup	Blow Down
Flow MLbs/Hr	107	107	92	15	107	107	107	30	10
BPD (SCFM)									
Temp °C	36	99	99	99	99	53	34	18	27
Press (PSIA)	330	300	280	280	280	70	68	30	15
Density /CF	34	26.7	3.3	3.3	3.3	0.7	33.8	62.4	62.6

Power Production:
Gas Engine 650 KW
Binary Cycle 541 KW
Total = 1,191 KW

Parasitic Loads:
Condensers 75 KW
Circ Pump 74 KW
Misc 60 KW
Total = 209 KW

NET POWER = 982 KW

Figure 27. Schematic illustration of the Hybrid Power System (HPS) installed and tested at Pleasant Bayou

The tabulated numbers summarizing operating conditions refer to the number test points (red numbers) in the schematic. Parasitic loads refer to design values. Actual total load varied from 260-306 kW, primarily reflecting higher than designed power load of the circulation pumps. (Source: Eaton Operating Company, Inc., Final Report, 1990.)

The hybrid power system demonstration at Pleasant Bayou was successful in all respects. Design power was achieved, and 3,445 MWh of electricity was sold to the local utility over the course of the test. Plant availability was 97.5 percent, and the capacity factor was over 80 percent for an extended run at maximum power production. Successful operation of the hybrid cycle power plant clearly demonstrated that there were no technical obstacles to electricity generation from the Pleasant Bayou geopressured resource. Other than surmountable issues associated with scaling due to the high total dissolved solid content of the typical reservoir brines, a power plant could be built and operated with no technical or economic obstacles. (The Pleasant Bayou hybrid plant is also described in the companion history report on Energy Conversion.)

3.3.2 Gladys McCall #1 Well

Design Well Gladys McCall #1 in Cameron Parish, Louisiana was tested for four years. This was the longest test of the program. Eleven potential production zones were identified in this well and two zones (zone 8 and zone 9) were flow tested.[74]

After setting a plug to isolate zone 9, zone 8 was tested beginning in December 1983, before being shut in to observe pressure buildup at the end of 1987. During the flow test, the well produced over 27 million barrels of hot (143°C [290°F]) brine; 676 million scf of gas exsolved from the brine. During the test period the well was flowed at various rates almost continuously; the average flow rate being 20,000 bbls/day. Like Pleasant Bayou #2, scaling problems were encountered during initial production and were solved by injection of phosphonate pills. Additional scaling issues in the well bore and the near well reservoir were also encountered and addressed (see Section 3.4). The encouraging results of this and other well tests provided proof that long-term high volume brine production was feasible and that gas-extracted brine could be successfully disposed by subsurface injection.

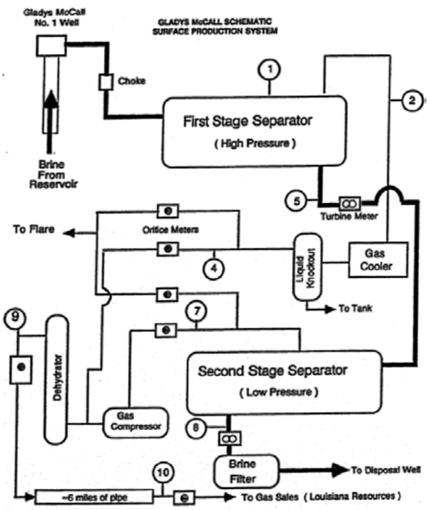


Figure 28a. Schematic illustration of the surface equipment installed to process the co-produced gas and brine. Numbered locations indicate sampling points.

SURFACE TEST EQUIPMENT FOR GAS PRODUCTION AND BRINE DISPOSAL

The objectives of the Gladys McCall test well were to 1) develop the capability for high flow rate production of high-pressure high-temperature brines and 2) evaluate the feasibility of producing the geopressured brine for gas extraction and sale. A schematic diagram of the surface equipment installed to process the produced brine is shown in Figure 28a.[75]

To accommodate the high brine flow rate, a block "Y" was installed on the production wellhead (Figure 28b). This diverted the flow up the well into two 45° heavy walled flow loops. These

Figure 28b. To accommodate the high brine flow rate, a block "Y" was installed on the production wellhead.

two flow loops made sweeping curves to the ground to another steel flow block that combined the two flow streams before entering the horizontal surface piping. The overall brine flow rate was controlled by a Willis choke downstream from the wellhead. Carbide disks in the choke were able to withstand the forces associated with the large pressure drop of several thousand psi. However, the intense turbulence of the fluid leaving the choke caused severe erosion of the interior pipe wall, which was made of low-grade carbon steel. This section of pipe was subsequently clad with stainless steel, which had the necessary metallurgical strength to withstand the abrasive high flow-rate turbulence.

To accommodate brine flow rates up to 40,000 bbls/day, the surface piping and valves were generally at least 5 inches in diameter. Equipment downstream of the choke was designed to operate at pressures up to 1,000 psi and temperatures up to 150°C (300°F). The gas/brine separators were of standard design with a pressure rating of 1,400 psi. Brine exiting the separators was filtered prior to injection into the disposal well and hydrocarbon gas from the separators was cooled and dehydrated prior to sale. Carbon dioxide was not removed since the gas sales contract allowed CO_2 up to 10 percent.

Several modifications and improvements to the surface processing system were made over time. In the final configuration, the two separators (high and low pressure) operated in series. Gas was separated from brine in the first separator at pressures high enough (approximately 1,000 psi) so that the produced gas could enter the sales line without further compression. The brine then passed to the second separator which was operated at 400 to 500 psi, sufficient to drive the spent brine down the disposal well while at the same time controlling the amount of CO_2 remaining in the disposed brine (the higher the separator pressure, the more CO_2 remains in the brine). Gas extracted from the second separator had to be re-compressed prior to injection into the sales line. Any remaining dissolved gas was injected with the brine into the disposal well.

3.4 Calcium Carbonate Scaling

Owing to the very high TDS of geopressured fluids, one of the most serious problems encountered during the long-term testing was the formation of calcium carbonate scale deposits. To further exacerbate the problem, scaling rates were found to increase with the brine production rate, particularly at production rates above 20,000 bpd. The scale deposition rate in the production tubing string is summarized in Figure 29 where both the decline in surface flow pressure and the loss in reservoir pressure are shown as a function of the surface flow rate. The discrepancy between surface and reservoir pressures reflects pressure loss due to friction during flow to the surface, which is a function of the ratio of the well-bore surface area in contact with the production fluid to the volume of fluid. Figure 29 shows that the frictional pressure losses in the well bore increase with increasing flow rate, reflecting the increase in the amount of deposited scale which lowers the surface area/volume ratio. Below production rates of 15,000 bpd, scaling was found to be minimal.

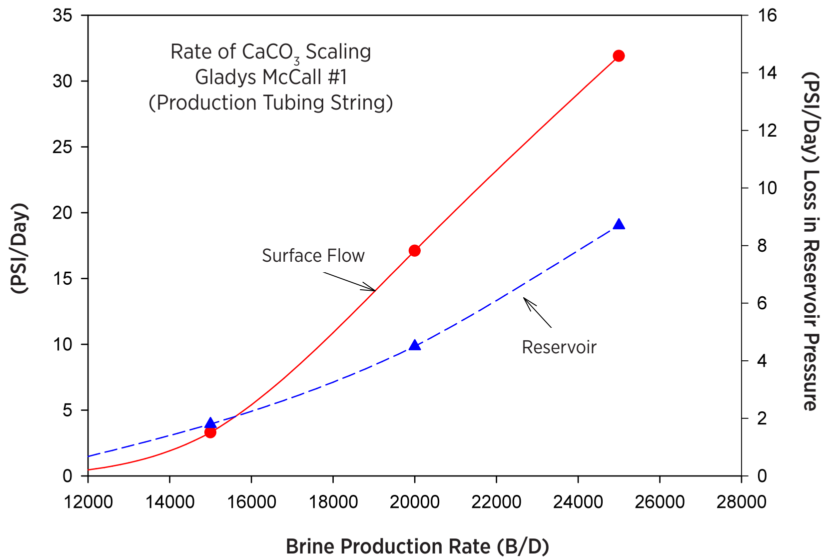


Figure 29. The impact of increased flow rates on the rate of calcium carbonate scale deposition (B/D: barrels per day)

The need for controlling scale was recognized early, and was already well known to all concerned with production of geopressured-geothermal fluids. Production-well tubing was removed from Pleasant Bayou after a series of production tests and was found to be scaled to a thickness of 0.5 inches to a depth of 3,700 meters (12,000 feet).[67] Three issues were addressed through a series of laboratory and field experiments conducted primarily by Eaton Operating Company and researchers at Rice University. The first issue was the removal of deposited scale. Second was minimizing corrosion effects related to scale removal, particularly downstream from the Willis choke in the Gladys McCall surface equipment (Figure 29). Third was the development of a protocol for inhibiting scale deposition in the wellbore so that flow rates for economic production (30,000 bpd) could be maintained.

Downhole scale deposits in the Gladys McCall Well could be readily removed by treatment with inhibited 15 wt % HCl. A series of three treatments conducted over a period of eight months resulted in the removal of 34,000 pounds (equivalent to a wellbore scale thickness of 0.22 inches), 25,000 lbs (0.17 inch thickness), and 50,000 lbs (0.36 inch thickness), respectively.

The operators knew from prior experience that calcium carbonate scale formation in the brine surface flow lines would be problematic. Therefore, scale inhibitor was injected into the surface flow lines at the onset of the flow tests. The polyphosphonate inhibitor Dequest 2000, manufactured by Monsanto Chemical Company, was diluted with water to an active strength of 2 to 3 percent then injected into the brine flow line upstream of the Willis choke (Figure 29). The resulting concentration in the brine line was 0.5 ppm by volume. In initial tests, the acid form of the polyphosphonate was used. However, this proved to be excessively corrosive on the injection piping and equipment, particularly in the turbulent zones downstream of the choke. To minimize the corrosive attributes of the inhibitor, subsequent tests used the neutralized form of the chemical.

Although the injection of inhibitor protected the surface piping and equipment from scale build up, it did not prevent scale deposition in the production tubing or wellhead upstream from the inhibitor injection points. Formation of scale in the production well tubing soon became apparent from degraded well performance. Although acid treatments could remove the scale, this was only a temporary measure as subsequent tests indicated a scale build-up rate of 20,000 pounds per million barrels of brine produced (Figure 30). This rapid rate of calcium carbonate scaling was unacceptable for maintaining production. A protocol was subsequently developed to prevent scale formation in the wellbore using inhibitor "squeeze" treatments that inject inhibitor into the production reservoir for scale mitigation prior to wellbore fluid entry. The squeeze treatments consisted of mixing a "pill" of a few percent phosphonate in brine. The pill was then pumped into the well and forced out into the reservoir formation. Once in the reservoir, the inhibitor chemical was either adsorbed on rock surfaces or reacted chemically to form a phosphonate precipitate. When brine production resumed, the inhibitor slowly dissolved into the brine that passed through the treated zone, inhibiting scale formation in the brine prior to wellbore entry.

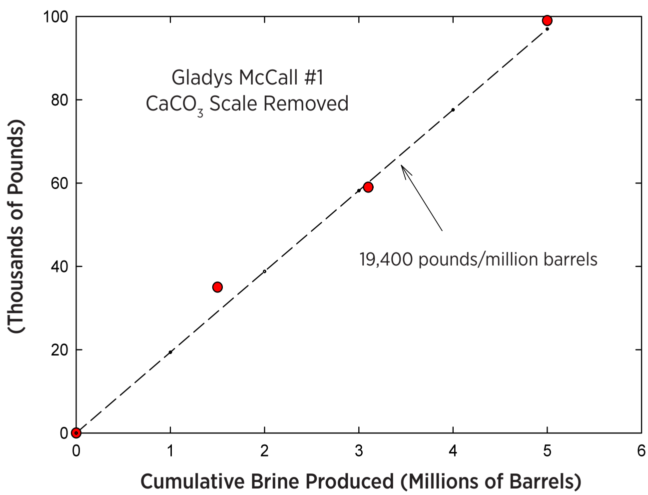


Figure 30. The amount of calcium carbonate scale removed by acid treatment shown as function of the cumulative amount of brine production. The rate of build-up is 19,400 pounds of scale formation per million barrels of brine produced.

This treatment successfully controlled scale formation in the wellbore and 13.3 million barrels of brine were produced with little or no scale build-up in the wellbore.

3.5 Environmental Issues

The main environmental concerns addressed by the Geopressured-Geothermal Energy Program were land-subsidence, growth-fault activation, and potential impacts on water quality from contamination of potable aquifers. The environmental monitoring arm of the program consisted of microseismic, subsidence and water quality monitoring. Continuous microseismic data collection was carried out by a network of recording stations set up near and around the design well test sites. No microseismic activity that could be reliably attributed to the well testing was recorded at any of these sites. Subsidence monitoring was conducted using a network of closely–spaced, first-order elevation benchmarks installed around the design well sites that were tied into the regional control networks of the National Geodetic Survey.

For the Gladys McCall site, although elevation changes were variable as a function of time, there appeared to be an overall elevation drop concentrated near the site, followed by a rebound. Researchers concluded however, that this movement was probably not related to testing since the elevation drop occurred after testing was stopped and could be explained as a localized reaction to oil and gas production or withdrawal of potable water. The changes in elevation, ranging from 4 to 10 mm/yr, were small but larger than the rate of regional subsidence. In general, the subsidence monitoring studies at Gladys McCall demonstrated variable, but small elevation changes. However, there was no conclusive evidence that regional and local subsidence rates were altered due to fluid withdrawal during geopressured-geothermal well testing.

To monitor potential impact on water quality, surface and groundwater samples were collected and analyzed quarterly. No problems arising from the well testing activities were observed. There were no harmful spillages at the surface or leakages into potable aquifers from the wells.

3.6 Economic Evaluation for Electrical Generation

An economic study of geopressured-geothermal electrical generation was conducted by INEL to evaluate the breakeven price to market energy from geopressured-geothermal resources.[76] The breakeven price is the minimum per unit charge required for a developer to recover all direct and indirect costs at a rate of return sufficient to compensate the developer for depreciation, the time value of money, and the risk of failure. A user-friendly model was developed to calculate the breakeven price to sell gas and electricity. The model used a present value methodology incorporating various conservative assumptions regarding 1) production well costs; 2) production possibilities (combinations of gas, thermal and hydraulic); 3) predevelopment cost; 4) pre-operation costs; 5) operational expenses; and 6) post-operation costs.

The present value method equates all past, present and future costs and revenues to a common point-of-time value. (Costs and revenues are cited in 1990 dollars, the value at the time of the analysis.) This is a generally preferred method because cash flows can be accounted on a real-time, common dollar basis by discounting all after-tax cash values to a present cash value using a discount rate. The discount rate is a percentage by which the value is reduced on a yearly basis. Because the discounting process significantly reduces the present dollar value of projects lasting more than five years, selection of the discount rate was a very important assumption. The INEL model used two different rates: 15 percent and 26 percent. The former was the commonly accepted rate for the development of mineral resources; the latter allows for a higher risk potential typical for oil and gas development where reservoir uncertainty and unpredictable circumstances can lead to a higher rate of failure.[77]

Due to its depth and size, the production well tends to be the largest single cost in the development of a resource. In most development scenarios, this cost can easily determine the success or failure of a project. However, for the purpose of the economic study, a developer of a geopressured-geothermal resource may not be faced with significant well costs for several reasons. First, a large number of potential production wells may be available because of the vast and historic development of oil and gas resources, many of which are associated with geopressured-geothermal zones. Second, the potential availability of a large number of wells suggests a market with a large supply and little demand, leading to very low market clearing prices for the Wells of Opportunity. For these and other similar market-driven reasons, the study assumed that the production well could be obtained for the cost to plug and abandon the well. However, as part of a sensitivity analysis, the study did include two scenarios where the production wells were drilled by the developer at a cost of either $5 or $10 million (in 1990 dollars).

Four different production scenarios were considered in the modeling:

A. Produce electricity from thermal energy only. Sell all methane. Both 15 percent and 26 percent discount rates were used.

B. Added cost to scenario A to produce electricity from a gas engine generator by burning all available methane gas. Because of the small difference between using 15 percent and 26 percent, the analysis conservatively assumed a 26 percent discount rate.

C. Added cost to scenario A to produce electricity from a hydraulic turbine using all available hydraulic energy. Because of the small difference between using 15 percent and 26 percent, the analysis conservatively assumed a 26 percent discount rate.

D. Produce electricity from all energy sources: thermal, gas and hydraulic. All methane gas is used to generate electricity. Both 15 percent and 26 percent discount rates were used.

To evaluate the sensitivity of different parameters and their impact on the breakeven price, such as well rework costs, production decline, etc., five additional constraints on the production scenarios were considered.

1. Sell all the produced methane gas; discard the thermal hydraulic energy.
2. No well rework costs: drill new production well at a cost of $5 million. Produce electricity using thermal, gas and hydraulic energy.
3. No well rework costs: drill new production well at a cost of $10.0M. Produce electricity using thermal, gas and hydraulic energy.
4. Assume two production wells available, alternating production every five years to allow for reservoir recharge. Includes additional costs for moving equipment, maintenance and equipment variability.
5. Brine flow rates decline linearly over a 10-year period from 40,000 to 10,000 bpd.

The INEL study focused on eight well cases using the attributes of seven different wells—three wells that penetrated formations with similar characteristics (Gladys McCall, Pleasant Bayou, and Hulin); two hypothetical wells defined as Best and Worst Case based on their assumed combined properties of temperature, wellhead pressure, and gas content which bracket the properties of the Design Wells; and two wells from the Wilcox Formation characterized most notably by higher temperatures (South Texas 400 and South Texas 500). The well characteristics (assumed or measured) and the breakeven prices (1990 dollars) for the four production scenarios are summarized in Table 9 for each of the eight different well cases.

In comparing all well cases, the hypothetical Best Case has the lowest breakeven price ($0.079/kWh) and the hypothetical worst Case has the highest ($0.404/kWh). In comparing all four production scenarios for each case well, scenario "D"—in which all forms of energy are exploited—has the lowest breakeven price. Of the six well cases with known well conditions, the two South Texas wells (400 and 500) have the lowest breakeven price, primarily because of the higher reservoir temperatures and higher gas contents. The Hulin well has the lowest breakeven price, again primarily because of the higher temperature. However, assuming the reservoir characteristics of the DOE Design Wells, the cost to convert geopressured-geothermal energy to electricity, which varies from $0.13 - $0.27 per kWh (1990 dollars), was higher than costs from conventional energy sources at the time of the study and significantly greater than the DOE program goal of $0.07-0.11 per kWh.

Table 9. Breakeven price to produce electricity from a geopressured-geothermal resource for selected well cases and production scenarios (A, B, C, D).

	WELL ASSUMPTIONS					POWER SOURCE		
CASE	Barrels (per day)	Top WHP (MPa)	Gas Cont. (scf/b)	Methane (vol %)	Temp (oC)	Generator Type	Capacity (kW)	Resource Life
1. Worst Case	10,000	5.516	20	85	123.9	gas	606	5
						geothermal	380	10
						hydraulic	33	
2. Gladys McCall	40,000	5.516	27	85	131.1	gas	3275	5
						geothermal	1850	10
						hydraulic	132	
3. Gladys McCall	25,000	5.516	27	85	131.1	gas	2050	5
						geothermal	1160	10
						hydraulic	200	
4. Pleasant Bayou	15,000	9.308	24	85	141.7	gas	1819	5
						geothermal	1420	10
						hydraulic	234	
5. Hulin	15,000	23.442	40	93	165.6	gas	1991	5
						geothermal	1301	10
						hydraulic	479	
6. Best Case	40,000	23.442	60	93	165.6	gas	8134	5
						geothermal	3450	10
						hydraulic	1276	
7. S. Texas 400	20,000	3.447	62	95	193.3	gas	4202	5
						geothermal	2610	10
						hydraulic	0	
8. S. Texas 500	20,000	3.447	100	95	248.9	gas	6778	5
						geothermal	4543	10
						hydraulic	0	

Breakeven prices are in 1990 dollars, with a 5 percent per year inflation rate. In certain scenarios, all capital and operating costs are escalated an addition 3 percent annually (3% ESC) to allow for a more conservative approach to potential cost overruns, etc.

Table 9. Continued from previous page

CASE	POWER SOURCE	15% DISCOUNT			26% DISCOUNT				
	Generator Type	3% ESC A $/kWh	3% ESC D $/kWh	0% ESC D $/kWh	3% ESC A $/kWh	3% ESC B $/kWh	3% ESC C $/kWh	3% ESC D $/kWh	0% ESC D $/kWh
1. Worst Case	gas	0.604	0.365	0.342	0.707	0.031	0.041	0.428	0.404
	geothermal	*	*	*	*	*	*	*	*
	hydraulic								
2. Gladys McCall	gas	0.182	0.122	0.114	0.215	0.031	0.041	0.145	0.137
	geothermal	0.168	0.114	0.103	0.201	0.028	0.038	0.136	0.126
	hydraulic								
3. Gladys McCall	gas	0.249	0.156	0.146	0.293	0.031	0.041	0.185	0.174
	geothermal	0.231	0.147	0.132	0.272	0.028	0.038	0.173	0.161
	hydraulic								
4. Pleasant Bayou	gas	0.241	0.158	0.149	0.285	0.031	0.041	0.188	0.172
	geothermal	0.225	0.149	0.135	0.266	0.028	0.038	0.177	0.164
	hydraulic								
5. Hulin	gas	0.232	0.140	0.132	0.273	0.031	0.041	0.166	0.157
	geothermal	0.214	0.131	0.119	0.251	0.028	0.038	0.155	0.144
	hydraulic								
6. Best Case	gas	*	*	*	*	*	*	*	*
	geothermal	0.106	0.071	0.065	0.127	0.028	0.038	0.086	0.079
	hydraulic								
7. S. Texas 400	gas	0.149	0.105	0.099	0.177	0.031	0.041	0.126	0.119
	geothermal	0.137	0.098	0.089	0.165	0.028	0.038	0.118	0.110
	hydraulic								
8. S. Texas 500	gas	0.119	0.089	0.083	0.143	0.031	0.041	0.107	0.101
	geothermal	0.109	0.082	0.075	0.132	0.028	0.038	0.100	0.092
	hydraulic								

Clearly, from this study reservoir temperature, gas content, and the exploitation of all three energy forms were the driving forces for economic viability. However, this economically driven well/reservoir selectivity, which favors the more hot, more gaseous reservoirs, would significantly limit the number of economically viable geopressured-geothermal resources. Issues not covered specifically by the INEL study, but which may impact overall economic viability, were technological improvements for utilization of the geopressured-geothermal resources and development of innovative and locally marketable direct uses for the energy. A good example of the latter is the use of hot pressured brine to recover medium and heavy oils, a concept partially proven viable by the demonstrated ability to inject hot spent brines into a secondary well during the Gladys McCall well tests. Furthermore, the economic analysis did not consider the potential cost savings attained from the use of shallow disposal wells, recompletion of wells of opportunity as disposal wells, or that for geopressured-geothermal systems fewer wells are needed per unit energy production.

3.7 Findings and Conclusions

The significant accomplishments of the Geopressured-Geothermal Energy program include:

1. Identification of geopressured-geothermal onshore fairways in Louisiana and Texas;
2. Determination that high brine flow rates (20,000 to 40,000 barrels per day) could be sustained for long periods of time using appropriate scale inhibition protocols;
3. Brine, after gas extraction, could be successfully injected into shallower aquifers without affecting surface waters or subsurface fresh water aquifers;
4. No observable subsidence or microseismic activity was induced by subsurface withdrawal and injection of brine, and no detrimental environmental effects attributed to well testing were observed;
5. Corrosion, sanding and scaling could be controlled with chemical inhibitors and by reducing flow rates;
6. Demonstration that the production of gas from saturated brines under pressure was viable; and
7. A hybrid power generation system could be installed and operated.

At the time of the research program prevailing economic conditions limited continued production from geopressured-geothermal reservoirs. However, the program laid the foundation for all aspects of future development of this extensive resource.

4.0 Modeling of Geothermal Systems

4.1 Reservoir Modeling Overview

The geothermal industry in the United States and around the world has long used the coupled well-bore-reservoir programs created or improved under DOE sponsorship to predict the behavior of geothermal wells under different assumed conditions (e.g., downhole temperatures and pressures, borehole diameters, total depths, and fluid feedzone depths). Without such computational tools, it would be difficult to estimate the evolution of fluid flow rates, pressures, and temperatures at the well head during the exploitation of a particular geothermal resource.

Modeling plays a key role in assessing, developing, and managing geothermal reservoirs. Geothermal reservoir modeling shares similarities to modeling for oil and gas reservoirs, but has distinct differences. While oil and gas reservoirs are typically near static equilibrium, geothermal reservoirs are open and highly dynamic systems that are subject to significant flows of mass and heat.

Modern reservoir modeling is often referred to as "numerical simulation," based upon a qualitative, conceptual level that graduates to quantitative analysis. Mathematical models have been developed to evaluate underlying processes of fluid flow and heat transfer in geothermal systems, including chemical behavior of geothermal fluids, mechanical interactions between fluids and rocks, rock deformation, and fracturing.

Reservoir management strategies are essential to achieving economic and sustainable geothermal fluid production. Modeling applications assess the production potential of a geothermal reservoir, aid the design and interpretation of well and laboratory test data, and help optimize energy extraction, reservoir production, and fluid injection management. Results from reservoir modeling are of keen interest not only to engineers, but also to utilities and investors as they evaluate the economic feasibility of geothermal projects.

4.2 Reservoir Modeling Considerations

Geothermal reservoirs are ever-evolving zones of fractured rock, requiring management throughout the life of the reservoir.[78] Effective reservoir management requires an understanding of a complex set of interactions, including interphase mass transfer, conductive and convective heat flow, and convective transport of fluids.[79] Given their coupled nature, studies of these interactions are difficult without an accompanying numerical simulation.

Numerical simulation begins with a conceptual reservoir model that identifies the most significant processes and maps attributes such as lithology, permeability, faults, and fractures into the reservoir, and defines the framework for their interplay within the reservoir. Such a model requires synthesis of data gathered from geologists, geophysicists, geochemists, reservoir engineers, and project managers.[80] Upon completion of a logical and rational conceptual model, reservoir engineers can then simulate potential responses of a reservoir to hypothetical situations, within the constraints of the conceptual reservoir model.

Numerical simulation efforts often require writing partial differential equations that govern the processes under investigation, including conservation of mass and energy, and transport. Simulations help predict reservoir processes and performance, facilitate identification of changing characteristics within a reservoir, and aid in the design of successful management strategies.

Calibration of reservoir simulation models with realistic reservoir behavior is necessary to ensure confidence in the models. A general procedure for model calibration consists of natural-state modeling followed by comparison against historical activity. Model calibration may require adjustments to improve correlation between generated results and field observations. This can be quite laborious, but is necessary to ensure sufficient reservoir evaluation.

As a cautionary note, while simulation efforts offer predictive capabilities, real reservoirs may evolve in a non-predictive manner.

4.3 Reservoir Modeling Techniques

Reservoir models have been the focal points of the DOE Geothermal Program since its inception in the mid 1970s, playing key roles in geothermal reservoir development, reservoir modeling, and tool development. During early phases of research, efforts were directed at clarifying the important physics to be included in models,[81-83] as well as at developing accurate, robust, and efficient methods for solving governing equations. The basic methodology and approach to geothermal reservoir modeling was developed in the 1980s, with substantial contributions from DOE-sponsored scientists.[84-86]

A growing body of field studies of geothermal reservoir behavior established a modeling methodology and track record of applications.[84-87] The effects of fluid injection were analyzed with the goal of maximizing favorable results and minimizing unfavorable impacts. Models were developed to predict the chemical behavior of geothermal brines and their associated phases over a wide range of compositions and thermodynamic conditions.[88-91]

New techniques were created to model fluid and heat flow in fractured media,[92-93] and to perform flow simulations with aqueous fluids that included dissolved solids and NCGs.[94] Subtle effects on vapor pressure—including capillary condensation and vapor adsorption—were incorporated into simulators,[95-96] and techniques for automatic history matching were developed.[97-98] Important developments include treating chemical interactions between rocks and fluids within the context of multi-phase, non-isothermal flows,[99-101] and using geophysical surveys to constrain reservoir models.[102-103]

A major early milestone was reached with a code intercomparison project conducted in 1979 and 1980, in which a variety of geothermal reservoir simulation codes were exercised on a set of hypothetical reservoir problems.[104] The project demonstrated growing technical capabilities and established credibility for the computer programs used. Most importantly, the work greatly increased worldwide acceptance of reservoir simulation studies.

The DOE Geothermal Program sponsored development of geothermal reservoir simulation programs and codes including SHAFT78, SHAFT79,[105] MULKOM,[106] TOUGH,[107-108] TOUGH2,[109-110] iTOUGH2,[111] and TOUGHREACT.[100-101] DOE also supported updates and enhancements to the commercially developed reservoir simulation code TETRAD[96/98] and the development of new codes to address coupling of fluid flow and heat transfer with rock deformation and fracturing.[112-113]

Additionally, DOE supported development of the PetraSim graphical user interface for the TOUGH and TETRAD computer codes.[114] This work facilitated improved preparation and presentation of modeling data, increased understanding of tracer behaviors, and broadening the appeal of numerical reservoir simulation.

The impact of DOE sponsorship of geothermal reservoir modeling has been significant for geothermal development. Methodologies for development of geothermal reservoir simulation codes permit an efficient and robust solution of geothermal reservoir problems. Models generated by DOE researchers have been widely adopted by the U.S. and international geothermal development communities. More than 125 field simulation studies were conducted in the 1990s alone, with approximately half of them using modeling software developed with DOE support.[115]

Much of the DOE-sponsored development work on geothermal reservoir modeling is published in the proceedings of various conferences, including Stanford Geothermal Workshops, Geothermal Resources Council Annual Meetings, World Geothermal Congresses, and TOUGH Workshops (called Symposia since 2003).

4.3.1 TETRAD for Geothermal Reservoir Modeling

TETRAD, distributed by ADA International Consulting Ltd., is a numerical reservoir simulator that can operate in four main modes: 1) black oil, 2) multicomponent, 3) thermal, and 4) geothermal. All of these modes can be combined with dual porosity (matrix and fracture). Features include definition of wells, grid refinement, and flexible boundary condition specification. Another commercially available simulator, PetraSim, supports creation of input geometry and properties, and plotting of results.

TETRAD has been validated against various problem types and when compared to other geothermal reservoir simulators on a set of tests, operates with similar precision.[116] In fact, TETRAD is one of the more user-friendly simulators available to the industry and contains all the features necessary for reservoir studies.[117] TETRAD uses the same equation package to simulate black oil, multi-component, thermal, and geothermal reservoirs. Each mode, however, has a different property package.[116]

A series of conservation equations are essential to the numerical simulation of a geothermal reservoir. Before simulation takes place, these conservation equations are discretized through finite-differencing techniques for easier computing.[116] The following physical phenomena can be modeled through TETRAD: phase partitioning of components, heat flow, relative permeability effects, capillary pressure, flow in fractured media, and semi-analytic aquifers and heat losses.

SIMULATION OF A HIGH-TEMPERATURE RESERVOIR WITH TETRAD

A series of papers by Idaho National Laboratory (INL) describe TETRAD simulation to investigate the formation of a high-temperature reservoir (HTR), as seen at The Geysers, California.[118-120] HTR is used to distinguish the difference between a normal vapor-dominated reservoir and the high-temperature conditions found below it. The following example describes the evolution of simulation efforts in determining how an HTR, similar to the one found at The Geysers, may have formed.

Initial TETRAD simulation efforts in 1993 assumed that the reservoir fluid was pure water, utilized thermal properties found in the literature, and, given the lack of existing data, arbitrarily assigned relative permeability and capillary pressures for the fractures and rock matrix.[118] The model used the following starting conditions:

- Pressure at the top of the reservoir was above saturation.
- Heat flux was restricted to the base of the reservoir, while the top was held at constant temperature and pressure.
- All other boundaries were considered no-flow.

After computations simulating 2,000 years within the model, a 20-year natural venting (mass withdrawal) due to thermal expansion was simulated.[120] Steady state eventually prevailed after simulation for 20,000 years, where heat losses to the caprock balanced heat flux applied to the bottom, establishing a vapor-dominated reservoir overlaying an HTR. This conclusion suggested that an HTR can develop as a steady-state component of a vapor-dominated reservoir. However, since several ad hoc assumptions were initially used to develop the model, further investigations were planned to evaluate their validity.[118]

A second TETRAD simulation effort was conducted by INL in 1994, with conditions similar to the 1993 study.[119-120] Because certain data from The Geysers was not available at the time, relative curves were used to infer permeability, which was then used with existing porosity and temperature data to generate capillary pressures. Instead of assuming the reservoir as pure water, the reservoir fluid was modeled with a uniform salt concentration of 3 weight percent (wt %), with an osmotic effect of approximately 0.95. Similar to the original model, the reservoir was vented after 2,000 years, but then opened for 60 years (instead of 20 years). After venting and re-equilibration most of the salt remaining in the system was highly concentrated within the HTR, about 20-40 wt %. Simulation was continued to 50,000 years (instead of 20,000 years).

In this case, HTR temperatures did not achieve steady state. Instead, throughout 45,000 years HTR temperatures fell 16°C (29°F). These results suggested that HTR formation is not a steady-state component of vapor-dominated reservoirs, but instead a transient feature (with transient times on the order of about 100,000 years). In addition, the HTR showed two distinct endpoints when simulated to 50,000 years—a dry cycle and wet cycle. This second simulation effort showed more of an agreement with field HTR observations, specific to large salt concentrations and lack of uniform depth.

Results of the 1994 simulation were similar to present-day field observations, suggesting that HTR may be transient in nature (over a very long period of time). However, a series of sensitivity analyses suggested that a number of different situations might have led to the formation of an HTR similar to that observed at The Geysers. Though it was impossible to assess the accuracy of the simulation model, several features made it appealing compared to prior modeling attempts.

The first Geysers HTR study in 1993 contained generalized assumptions, such as pure water for reservoir fluid and arbitrary assignment of values for relative permeability and capillary pressures. While these assumptions were effective in creating a model of an HTR beneath a normal vapor-dominated reservoir, they suggested that HTRs are a steady state component of vapor-dominated reservoirs. Yet when rational data were used (e.g., reservoir fluid as a two-component system of water and salt, and honoring all available data), modeling results were comparable to field observations of the existing HTR, and suggested that HTRs are not a steady-state component, but more likely transient in nature.

These sequential TETRAD simulations of the HTR at The Geysers show that available data should be used along with best estimates for non-existing data regarding the nature of geothermal reservoirs. Even disparate models and simulations offer insights into complex reservoir interactions. This knowledge can ultimately assist field managers in reservoir management decision-making.

UPDATES TO TETRAD RESERVOIR SIMULATION SOFTWARE

Reservoir simulation software must be updated as needed to help develop reservoir models that take advantage of observations during exploration and at existing geothermal fields. To enhance reservoir simulation capabilities, INL set out to simplify and generalize the process of identifying and estimating input parameters before employing them in TETRAD simulations.[121] The first part of that effort was to couple TETRAD results with a suite of geophysical codes. This was completed with validation and verification studies by 2002.[122] The second part was to develop a new code that would provide an inverse interface to generate conceptual models used by TETRAD.

For several years, geothermal reservoir simulation results were used in geophysical model post-processing for improved reservoir management, most notably by Japanese researchers (New Energy and Industrial Technology Development Organization [NEDO]) and SAIC. INL researchers obtained permission to interface those geophysical models with their existing reservoir model and TETRAD.[150] They initially developed TETRAD code modifications—including geophysics output and new keywords for defining rock types on a regional basis—with test cases using direct current (DC) resistivity, self potential, and microgravity models.

In addition to continually updating the software to support simulation, models for reservoir management decisions also require some semblance of history matching to estimate reservoir properties. That history match effort may be manual (i.e., with reservoir properties modified by a reservoir engineer to match observed field behavior), or automatic (i.e., with reservoir properties estimated via mathematical methods). Both methods can be time-consuming.

To automate the process, INL developed a public domain model for reservoir parameter estimation called TET^{-1}. The model performed joint inversion of TETRAD and geophysics models through an independent inverse model called Parameter ESTimation (PEST). The goals of an inverse model are to: 1) automate the time-consuming process of estimating reservoir properties for management, 2) remove possible modeler bias in parameter estimation, and 3) provide property correlation and uncertainty statistics of the property estimations themselves.

Using TET^{-1} to couple the reservoir simulator TETRAD with the inverse model PEST showed great promise. The project explored statistics generated by PEST during an optimization scheme for use in sensitivity analysis and uncertainty propagation. By including additional predictions and observations, TET^{-1} obtained better and more certain reservoir parameter estimates and excellent results for numerically challenging problems. TET^{-1} was made publicly available in 2003 for use in a variety of fields, including design and interpretation of lab-scale experiments, tracer test interpretation, and reservoir management schemes.

Based upon PEST, the final version of TET^{-1}, consisting of a suite of files that ran the forward model TETRAD, created observation and prediction output files used in determining parameter estimated updates; and modified input parameters, etc., until pre-set parameter estimation convergence criteria are met. TET^{-1} allowed the user to create and modify the TETRAD input deck either graphically or manually. By defining regions within the TETRAD domain and parameters within those regions, parameter estimation is accomplished external to any proprietary software. TET^{-1} could be run on any existing version of TETRAD.

EVALUATING WELLBORE HEAT EXCHANGERS WITH TETRAD

Enhanced Geothermal Systems (EGS) are typically delineated as either permeability or fluid limited. An extreme EGS condition has neither sufficient permeability to induce flow nor working fluid to circulate through a rock formation. Under these conditions, heat extraction via circulation in a wellbore was proposed as a means of geothermal power generation or direct use applications without resorting to massive hydraulic stimulation.

In 2003, INL conducted a numerical study using TETRAD to evaluate the potential for using a Wellbore Heat Exchanger for geothermal power generation.[153] The work was an extension of preliminary studies conducted at SNL and offered a comprehensive numerical evaluation of the proposed method. A variety of sensitivity studies were conducted to understand variations in operational and regional properties, and how they affected heat transfer. Variables included operational parameters such as circulation rates, wellbore geometries and working fluid properties,and regional properties including basal heat flux and formation rock type.

With wellbore heat extraction (WBHX), a working fluid is circulated in a closed loop entirely within the confines of a well. There is no contact between the working fluid in the well and the surrounding rock, other than heat conduction across the well perimeter itself. The wellbore consists of production tubing, insulation, casing, and cement. The well is cased and cemented to a certain depth, and the remaining portion of the well is retained as an open hole. The tubing is insulated and extended to the wellbore bottom. The fluid is injected in the annulus, and gains heat from the formation as it descends. The hot fluid then rises up through the tubing to the surface. Power generation can take place either at the surface or downhole. Temperature differences are small because fluid residence time in the tubing is small relative to the heat transfer rate.

From the numerical model developed with TETRAD to investigate the potential for power generation with a WBHX, the following specific conclusions were drawn:

1. A trade-off exists between circulation rate and energy extraction rate. This implies an intermediate optimum circulation rate, which maximizes heat transfer to the circulating fluid.

2. For fixed circulation rates, any increase in residence time of the fluid in the wellbore enhanced energy extraction. This included wellbore diameter and well depth.
3. For fixed bottom-hole temperature, lower basal heat flux was better because it led to deeper wells and, hence, longer residence times. This assumption ignored developer costs incurred with deeper drilling.
4. Minimum tubing insulation was required. Enhancements to either insulation or changes in diameter had no appreciable effect.
5. Energy extraction was very sensitive to thermal properties of the rock. Larger thermal conductivities and larger thermal diffusivities led to improved energy extraction.
6. Trade-offs existed between the working fluid's heat capacity and the extraction temperature.
7. Water appeared to have optimal or near-optimal properties to provide reasonable energy density at acceptable temperatures.

A Best Case WBHX design used circulation rates far below those of any low-temperature power plants, and provided fluid temperature also below plant specifications. Even assuming ideal conversion of the thermal energy, a WBHX produced less than 200 kW of power at pseudo-steady state (pss). Using realistic conversion rates, a WBHX would generate less than 50 kW at pss and that rate declines with time.

4.4 The TOUGH Family of Codes

The TOUGH family of codes was developed at LBNL, primarily for applications to geothermal reservoir engineering. TOUGH2, a numerical simulation program for non-isothermal flows of multiphase, multicomponent fluids in permeable (porous or fractured) media, also developed at LBNL was released to the public domain in 1991.[123] Additional fields of application that led to further development and enhancements include nuclear waste disposal, environmental remediation and vadose zone hydrology. A summary of the TOUGH family and development is given in Table 10.

Table 10. Development of the TOUGH codes

(NAPL: nonaqueous phase liquid; NCG: noncondensable gas; VOC: volatile organic compound)

Simulator	Application	Phases (Components)	Comments
MULKOM	geothermal, nuclear waste, oil and gas	multi (multi)	research code, operational 1981, no public release
TOUGH	geothermal, nuclear waste	aqueous, gas (water, air)	released 1987
TOUGH2	general purpose	aqueous, gas (water, NCG's)	released 1991
T2VOC	environmental	aqueous, gas NAPL (water, air, VOC)	released 1995
iTOUGH2	inverse modeling; sensitivity analysis, uncertainty propagation	multi (multi)	released 1999
TOUGH2 V 2.0	general purpose	multi (multi)	released 1999
TMVOC	environmental	aqueous, gas NAPL (water, air, multiple VOCs and NCGs)	released 2002
TOUGHREACT	reactive chemistry	aqueous, gas, solid (multi)	released 2004
TOUGH-FLAC	geomechanics	aqueous, gas (water, CO_2)	research code

The precursor to the current TOUGH codes was a simulator program known as MULKOM, which was developed at LBNL in the early 1980s (Table 10). MULKOM's architecture and methodology was based on the recognition that the governing equations for non-isothermal flows of multicomponent, multiphase fluids have the same mathematical form, regardless of the nature and number of fluid components and phases. MULKOM was a research code that served as a test bed for developing much of the approaches and methodology subsequently implemented in TOUGH and TOUGH2. A stripped down version of MULKOM for two-phase flow of water-air mixtures was released into the public domain in1987 under the name TOUGH.[107] A more comprehensive subset of MULKOM modules was later released under the name TOUGH2[108] through the Department's Energy Science and Technology Software Center (ESTSC), and was most recently updated to TOUGH2 version 2.0.[110]

Development and enhancement of the TOUGH family was a continuous process. There were several offshoot codes for a variety of specific problems related to geothermal engineering, nuclear waste management, and environmental remediation. Offshoots most related to geothermal issues included:

1. iTOUGH, which provided capabilities for inverse modeling, optimization, and sensitivity and uncertainty analysis;[111]

2. TOUGHREACT, which coupled TOUGH2 with a general chemical speciation and reaction progress package;[124] and

3. TOUGH-FLAC, which was a research code that coupled TOUGH2 with the commercial rock mechanics code FLAC3D.[125]

Since the early 1980s, the development of TOUGH2 was driven by a desire to model specific types of flow systems with a focus on geothermal reservoir dynamics. Among the important issues for geothermal reservoir modeling were the non-isothermal nature of flow, the importance of phase change (boiling and condensation), and the highly non-linear nature of two-phase (water-steam) flow. The first functional version of MULKOM was a single-porosity simulator that solved a mass balance for water and an energy balance; NCGs or dissolved solids were not included. In geothermal reservoir problems, the coupling between the mass and energy balance equations can be very strong, severely limiting the time step for which a sequential iteration will converge.

For example, for cold water injection into a vapor-dominated reservoir, like that at The Geysers which would entail rapid vaporization with strong latent heat effects, a sequential solution of mass and energy balance equations would converge only for time steps of a few hours.[126] Accordingly, a fully simultaneous solution of mass and energy balances and fully implicit time stepping to overcome impractical time step limitations were implemented. The current version of TOUGH2 includes sophisticated iterative solvers designed to handle severely ill-conditioned problems.[127]

Geofluids typically include NCGs and dissolved solids, primarily CO_2 and sodium chloride (NaCl). The needs of geothermal reservoir modeling naturally led to the development of fluid property modules for fluid mixtures, with the main focus on CO_2.[128] Furthermore, fluid flow in most geothermal reservoirs was fracture-dominated and cannot be adequately described with single-porosity approaches. Used for space discretization, Integral Finite Difference (IFD) was introduced into the MULKOM and TOUGH codes. IFD offered a great deal of flexibility in the geometric description of flow systems; double- and multiporosity techniques for fractured media could be implemented simply by pre-processing geometric data, without any coding changes.[129] Besides work done largely at LBNL on the TOUGH family of codes, other workers have also made additions and adaptations to enhance these codes.[130-131]

4.4.1 Applications of TOUGH

During the 1980s, MULKOM and TOUGH were applied extensively to geothermal reservoir studies, primarily in the following capacities:

1. Natural state modeling [e.g.,[132]];
2. Design and analysis of well tests [e.g.,[133]];
3. Production and injection problems in producing geothermal fields;[134-135]
4. Fundamental studies of geothermal reservoir dynamics: e.g. fluid reserves and production of superheated steam from fractured, vapor-dominated reservoirs;[136] fluid and heat flow in fractured porous media;[137] modeling of vapor-dominated geothermal reservoirs in fractured porous media;[138] fluid and heat flow in gas-rich reservoirs;[139] and heat transfer at a boiling front moving through a porous medium.[140]

EXAMPLE: THE NATURAL STATE OF THE KRAFLA, ICELAND GEOTHERMAL FIELD

To properly evaluate the potential and development of a geothermal field, a natural state model of the field must be developed that is consistent with all available data, including observed thermodynamic conditions (e.g., vertical and lateral pressure and temperature distributions, fluid chemistry), available transient data, and the exploitation history (e.g., flow rate decline of wells and the pressure decline in the reservoir). Using these types of data, a good conceptual natural state model will be able to identify fluid upflow zones, fluid flow patterns, and discharge areas. The role of the natural state model in the general application of reservoir evaluation is depicted in Figure 31.

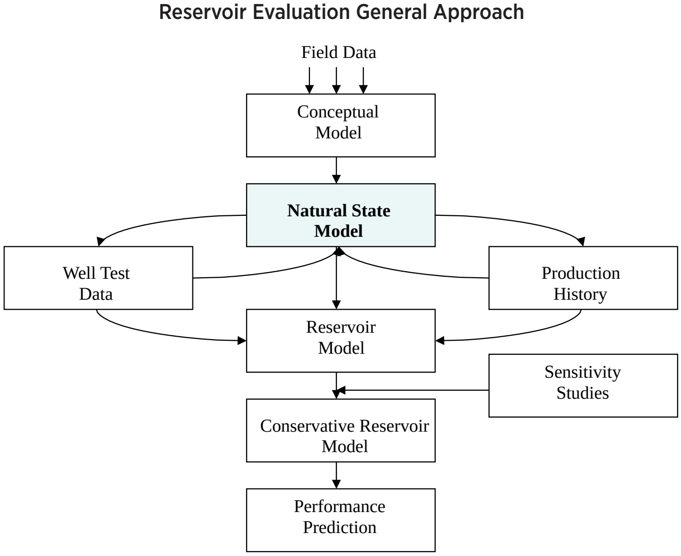


Figure 31. The role of the Natural State Model in reservoir evaluation and performance prediction

In 1984, with support from DOE, LBNL researchers developed a natural state model for the evaluation of the Krafla, Iceland geothermal reservoir.[85] The geothermal field is located in the neo-volcanic zone of northeastern Iceland characterized by fissure swarms associated with central volcanoes. The field is located within the Krafla caldera. At the time of the study, the field had been under production for nearly a decade. Drilling had encountered two major reservoirs. One was an upper reservoir (200-1,000 meters [600-3,000 feet] depth) that contained single-phase liquid water with a mean temperature of 205°C (401°F). The other was a deeper two-phase reservoir with temperatures and pressures following the boiling point curve with depth and maximum temperatures as high as 300-400°C (600-800°F). The two zones were thought to be separated by a thin (200-500 meters [600-1,500 feet]) low permeability layer, but seemed to be connected.

A two-dimensional vertical model was developed consisting of a 100-element mesh varying in size from 10,000 m3 to 80,000 m3, with the smaller elements located close to presumed upflow zones. The rather coarse mesh reflects the computational capabilities available at the time of the study. The section was subdivided into eight zones representing reservoir rocks with different physical properties, specifically thermal conductivity and permeability. Rock zones with higher permeability (major vertical and horizontal fractures) were necessary to match field data.

The calculated natural state temperature distribution and fluid flow paths computed for the Krafla field are shown in Figure 32.[87] The computed model clearly depicted many of the salient features of the reservoir: the high permeability fracture fault zones in the Hveragil area, the inferred upflow zones to the east, a known horizontal fracture zone (zone of higher permeability) at a depth of about 1,000 meters (3,000 feet), as well as the near-surface high temperatures east of Hveragil. Furthermore, quantitative estimates of mass, enthalpy and location of surface discharges compared well with the estimated values from surface measurements.

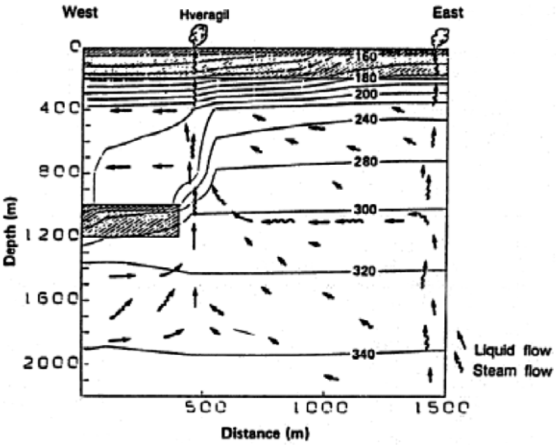


Figure 32. The natural state temperature distribution and the fluid flow patterns computed for the Krafla field

Overall, the computed model met the main objectives of the study which were to 1) verify a conceptual model of the field, 2) resolve the mechanism that controls the low temperatures in the upper zone, which is recharged by fluids of much higher temperatures, 3) quantify natural mass and heat flows in the reservoir, 4) verify transmissivity values obtained from injection tests and 5) obtain a better understanding of the dynamic nature of the reservoir.

Geothermal applications remain a prominent area for TOUGH2.[141] A special issue of *Geothermics*[142] was dedicated to the application of TOUGH2 in geothermal reservoir studies. The issue assembled examples and trends in geothermal reservoir simulation that were presented at the "TOUGH Symposium 2003" held at LBNL.

4.4.2 TOUGHREACT

Beginning in the mid 1990s, efforts were made to develop capabilities for reactive chemical transport. This was initially motivated by problems in mining engineering, such as the enrichment of protore during weathering processes,[143] and was later focused on chemical issues in geothermal systems culminating with the release of TOUGHREACT.[144] To address issues related to hydromechanical stability of cap-rocks associated with the geologic sequestration of CO_2, researchers coupled TOUGH2 with the commercially available FLAC3D code.[145] The coupled code has since been used to study the impact of injection and production on the hydromechanical evolution of geothermal fields, most notably at The Geysers geothermal field.[146]

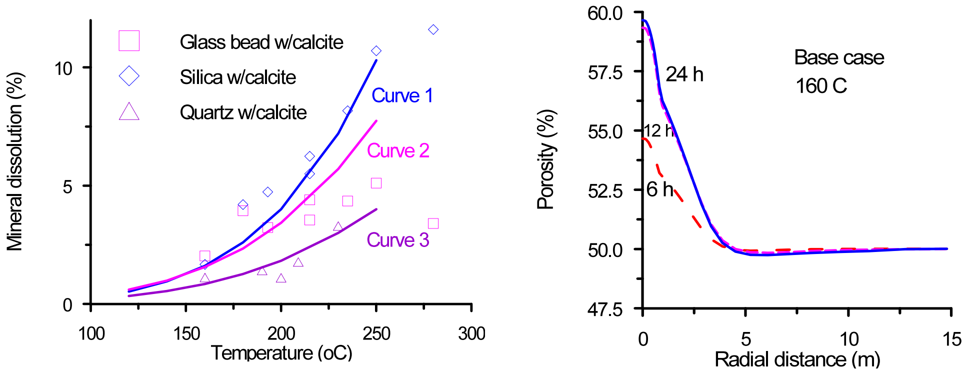
TOUGHREACT is a numerical simulator for chemically reactive non-isothermal flows of multiphase fluids in porous and fractured media. It was developed by introducing reactive chemistry into the multiphase fluid and heat flow simulator TOUGH2. The development was initiated with funding from the Laboratory Directed Research and Development Program of LBNL (1996-1999). Subsequent development was supported primarily by the DOE Geothermal Program.

TOUGHREACT can be applied to one-, two- or three-dimensional porous and fractured media with physical and chemical heterogeneity. The code can accommodate any number of chemical species present in liquid, gas, and solid phases. A variety of subsurface thermal, physical, and chemical processes are considered under a wide range of conditions of pressure, temperature, water saturation, ionic strength, and fluid acidity (pH) and oxidation/reduction potential (Eh). Temporal changes in porosity and permeability due to mineral dissolution/precipitation and clay swelling are also considered.

TOUGHREACT is among the most frequently requested codes in the library of the Department of Energy's Software Center. It has been widely used nationally and internationally for geothermal problems such as formation scaling due to water injection, optimization of injection water chemistry, and mineral alteration in hydrothermal and geothermal systems.

EXAMPLE: CHEMICAL STIMULATION USING CHELATING AGENT

Dissolution of silica and calcite in the presence of chelating agent Nitrilotriacetate (NTA) at a high pH was successfully demonstrated in laboratory experiments using a high-temperature flow reactor. The mineral dissolution and associated porosity enhancement in the experiments were reproduced by TOUGHREACT modelling (Figure 33). The chemical stimulation method was applied by numerical modeling to a field geothermal injection well system to investigate its effectiveness. Parameters applicable to the quartz monzodiorite unit at the EGS site at Desert Peak, Nevada were used. Results indicate that the injection of a high pH chelating solution results in dissolution of both calcite and plagioclase, while avoiding precipitation of calcite at high temperature conditions. Consequently, reservoir porosity and permeability can be enhanced especially near the injection well.



(a) Lab experiments (b) Field application

Figure 33. Chemical stimulation using chelating agent Nitrilotriacetate (NTA)

4.4.3 TOUGH-FLAC

The TOUGH-FLAC simulator[125] is based on a coupling of two existing computer codes: TOUGH2[110] and FLAC3D. TOUGH2 is a well-established code for geohydrological analysis with multiphase, multicomponent fluid flow and heat transport. FLAC3D is a widely used commercial code designed for rock and soil mechanics. For analysis of coupled thermal-hydraulic-mechanical (THM) problems, TOUGH2 and FLAC3D are executed on compatible numerical grids and linked through external coupling modules, which serve to pass relevant information between the field equations. TOUGH-FLAC simulates complete two-way coupled THM processes in fractured geological media, including effects of temperature and fluid pressure on stress and strain, and effects of stress and strain on permeability.

The TOUGH-FLAC simulator was used to evaluate the cause and mechanisms of induced seismicity at the Geysers Geothermal Field. Figure 34 shows an example of simulation results of coldwater injection into an injection well Aidlin 11, Northwest Geysers. Going from left to right it is evident how the cold water injection changed pressure (a few mega pascals [MPa] increase), saturation (increased liquid saturation in fracture system), temperature (cooling by 50°C [120°F]), and the resulting microearthquake (MEQ) potential. The highest MEQ potential represent a volume where the stress field has changed in such a way that shear reactivation of pre-existing fractures are likely.

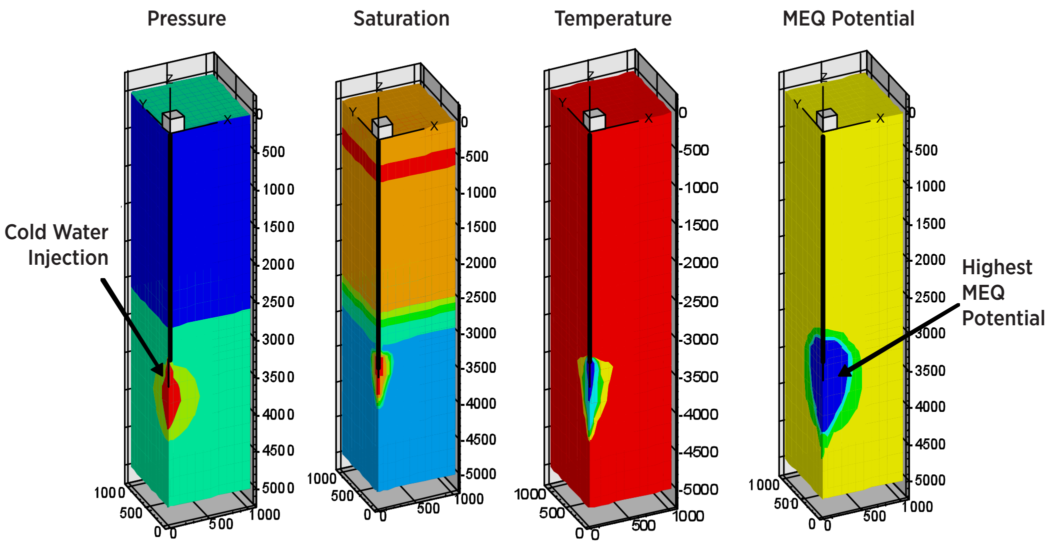


Figure 34. Results of coupled thermal-hydraulic-mechanical (THM) analysis of microearthquake (MEQ) potential associated with coldwater injection at Aidlin 11, Northwest Geysers, California

The concepts that developed in the early 1980s for the TOUGH family of codes have proven to be sufficiently flexible to accommodate many useful enhancements. The general objective for the development of the codes was to improve the power and utility of geothermal reservoir simulation as a robust and practical engineering tool. By making state-of-the-art simulation capabilities widely available to the geothermal community, DOE hoped that uncertainties in geothermal reservoir delineation and evaluation would be significantly reduced.

4.5 Wellbore Models

Because geothermal wells often draw fluids from different feedzones, it is necessary to accurately simulate the interaction between the boreholes and the reservoir formation. As part of its geothermal reservoir engineering studies, DOE funded development of wellbore modeling codes that simulate transport of heat and fluid from the geothermal reservoir (or feedzones) to the wellhead. Coupling between the borehole and surrounding rocks is included in the calculations. In some cases, brine chemistry was considered in the analysis.

DOE supported the development and improvement of several geothermal reservoir-wellbore simulators, primarily through work at LBNL.[147-149] In a few cases, reservoir and wellbore models were run interactively to more realistically simulate the interaction between underground and surface conditions.[150]

4.6 PetraSim Graphical User Interface

DOE supported early development of the software program PetraSim[151] through the Small Business Innovation Research (SBIR) program. PetraSim is a graphical user interface for TETRAD and the TOUGH2 family of codes. These simulators are recognized for their powerful modeling capabilities involving fluid flow and heat transfer in porous and fractured media. The TETRAD and TOUGH2 codes have been applied to a multitude of problems, including geothermal reservoir engineering, hydrogeology, geologic radioactive waste disposal, multi-component environmental remediation, and geologic CO_2 sequestration.

PetraSim has four key features that helped to speed and simplify the use of TETRAD and TOUGH2 codes:

1. Use of a high-level mode description based on geometric features of the reservoir;
2. Presentation of required input options grouped in a logical format with appropriate default options activated;
3. Automatic writing and execution of input files; and
4. Rapid access to visualization of results.

Figure 35 shows an example of an iso-surface plot of temperature done using PetraSim.

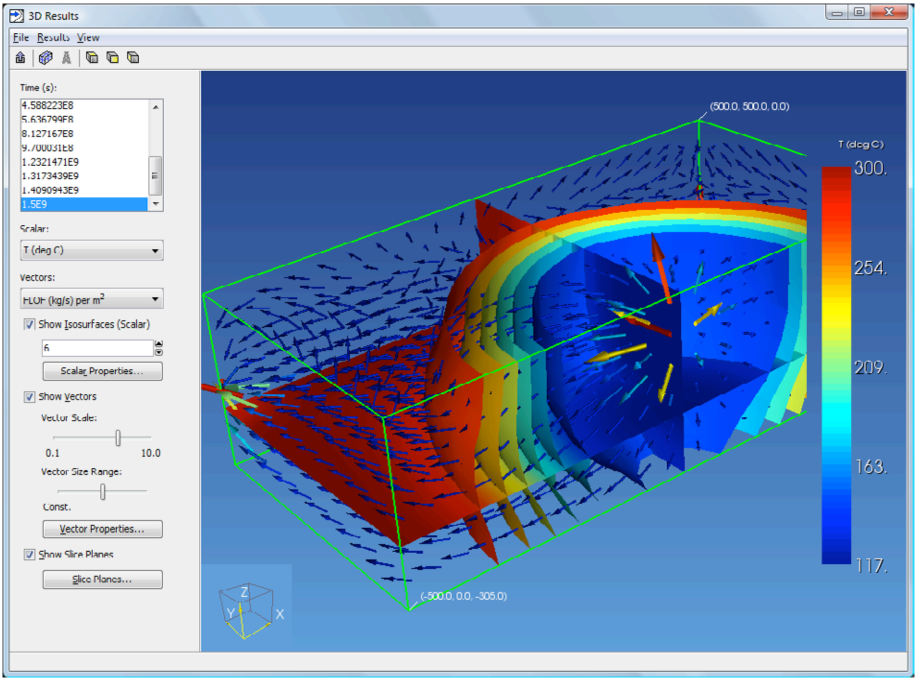


Figure 35. Iso-surface plot of temperatures using PetraSim

The primary impact of PetraSim involved the dissemination of technology developed by LBNL in the TOUGH2 codes to a much larger audience than would otherwise be possible. Programs for computing properties of multicomponent, multiphase fluids have been developed and made available to the public through the Internet.[152]

While there has been some use of TOUGH2 for geothermal analysis, applications of PetraSim and corresponding TOUGH2 codes also made a substantial impact beyond the geothermal community in areas such as nuclear waste isolation,[153] environmental remediation,[154-155] and more recently, the geologic storage of greenhouse gases[156] and recovery of methane from hydrate deposits.[157]

5.0 Geoscience Support Projects

The following is a summary of several important geoscience projects that were judged to have had a lasting impact on geothermal technology.

5.1 Tracer Development

A tracer is a distinctive substance injected into a volume of fluid for the purpose of characterizing or "tracing" the flow of that fluid. Tracer compounds can be divided into two groups: 1) chemically inert and 2) physio-chemically reactive. Inert tracers are useful in providing model-independent information, such as the degree of well-to-well connectivity, dispersive characteristics, and fracture volume. Temperature-sensitive, chemically reacting, or adsorbing tracers can provide insight into heat extraction efficiency along a flow path, leading to construction of detailed reservoir models with predictive capabilities.

Since 1981, the DOE Geothermal Program has sponsored research for the development and use of tracers in geothermal reservoirs. The work was focused on three main areas:

1. Development and application of analytical and numerical models to determine well-to-well connectivity and flow rates,[158] dispersion,[159-160] flow impedance, heat transfer, and fluid sweep volumes[161-163] using breakout and return data.
2. Laboratory studies to identify and test chemical tracers appropriate for the high temperatures encountered in geothermal environments, in order to infer both liquid and gas flow through the system and to provide a wide diversity of tracers to allow for multiple injections into different wells without cross contamination.[164-169]
3. Field tests to verify the laboratory, modeling, and numerical studies.[168-175]

Success of the effort was driven by an effective integration of the various analytical, laboratory, numerical, and field studies. The research was carried out by several groups, most notably the Energy& Geoscience Institute (EGI) of the University of Utah, Stanford University, Massachusetts Institute of Technology (MIT), and National Labs including INL, LBNL, and LANL.

In the early stages of tracer development studies, researchers established that some chemical compounds routinely used in groundwater tracing lacked the requisite stability at the higher temperatures encountered in most geothermal systems. Therefore, early laboratory work focused on the decay kinetics of these compounds, determining which chemical characteristics were responsible for providing thermal stability (inert tracers), and quantifying temperature-dependent reaction rates (chemically reactive tracers). A sampling of the various types of tracers, how they were used, and what could be learned from well-designed tracer tests was published in 2001.[176]

The ideal tracer compound should be inexpensive for use in large quantities, environmentally benign, detectable at very low concentrations (less than 1 parts per billion [ppb]) to accommodate large dilution factors, and preferably absent from natural geothermal fluids. Some tracers that occur naturally, however, have shown promise (e.g., the chemically inert noble gases). Tracers available to the community prior to the DOE R&D program, as well as their advantages and disadvantages are listed in Table 11.[166] (Activable tracers are stable chemical elements whose analysis is done by neutron activation of them, allowing the advantages of detection in low concentrations through radioactive counting without actually putting radioactive material in the ground.)

Table 11. Advantages and drawbacks of tracers used in geothermal systems

Tracer	Advantages	Disadvantages
Halides (e.g. (Cl-)	Stable Inert	High natural backgrounds
Radioisotopes (e.g. ^3H)	Detectable at low concentrations	Toxicity (radioactive halides) Natural background (^3H)
Activable	Detectable at low concentrations	Low and poorly defined stability
Fluoroscein	Well-defined kinetics Detectable at low concentrations Simple field analysis	Decays rapidly at temperatures > 260°C (500°F)

The tracers described in Table 11 have almost entirely been replaced in the United States and around the world by a new family of geothermal tracers—the naphthalene sulfonates.[177] These compounds owe their excellent thermal stabilities to their condensed aromatic ring structure and to the strength of the aryl-sulfonate bond. Eight naphthalene sulfonates that have been tested in the laboratory and the field and are available in bulk.[178-183]

Decay kinetics studies showed that all of the naphthalene sulfonate compounds are suitable for use in reservoirs with temperatures up to 330°C (626°F). Some are suitable for use in reservoirs as hot as 350°C (662°F). In addition to possessing excellent thermal stability, these compounds, being fluorescent, are detectable to approximately 100 parts per trillion by conventional high-performance liquid chromatography (HPLC). Such low detection limits mean that relatively small quantities of tracer are needed for interwell tracer testing. In addition, these compounds have been shown to be both environmentally benign and resistant to biodegradation.[184-185]

Significant advancements were also made in the use of short-chain aliphatic alcohols,[186] enabling tracer studies within two-phase liquid-vapor systems. The development of a novel solid-phase micro-extraction (SPME) method of analysis allowed for the significant reduction in detection limit for this class of tracers, thus greatly reducing the quantity required and thereby rendering them affordable for use as an interwell tracer.[187-188] Numerous tracers developed under DOE funding at EGI were deployed and tested in close collaboration with industry partners and have gained wide acceptance throughout the world.

Parallel to the tracer development research, significant advancements were made in the development and testing of models for extracting relevant information from tracer returns and break-out curves.[189-196] These advancements are discussed in greater detail in Section 5.2 below.

The tracers and tracer technologies developed under the DOE Geothermal Program are being used throughout the industry for field and reservoir characterization. The tracers enable estimates of inter-well connectivity, inter-well flow rates, sweep volumes, etc. The development of new and more robust tracers also led to improved interpretation technologies (see Section 5.2). DOE-sponsored tracer development resulted in the following accomplishments:

- Detailed laboratory characterization of the thermal decay kinetics of fluorescein—the first geothermal tracer to gain widespread application in the geothermal industry.
- The characterization and testing (in the laboratory and in the field) of the first thermally reactive tracer to measure the effective temperature along an injection/production pathway.
- Detailed laboratory characterization of the thermal decay kinetics and field-testing of the naphthalene-sulfonate family of geothermal tracers. These thermally stable and detectable tracers are used extensively in geothermal fields around the world.
- The development of a new method that allows for the very sensitive detection of short-chain aliphatic alcohols to be used as tracers in two-phase liquid-vapor fields.

5.2 Tracer Interpretation

Tracers are important tools for reservoir characterization. They provide preliminary qualitative information, such as directional flow paths, relative interwell connectedness, and presence of flow barriers. Through quantitative analysis, however, additional hidden information about the reservoir properties may also be obtained. Consequently, tracer interpretation technologies are critical to maximizing the benefit that geothermal tracers can provide.[194] Both the qualitative and quantitative information gained from tracer analyses, in addition to other well testing data, can provide reservoir engineers with the information they need to develop a reliable conceptual reservoir model, which can in turn be used to predict performance during operation. By comparing the model to actual performance, an engineer can modify the reservoir management plan to obtain more efficient operation.[197]

Of particular interest to geothermal developers is a geothermal reservoir's ability to sustain adequate heat transfer rates—a key factor in determining commercial viability. As a result, significant advancements have been made in tracer interpretation to estimate fracture-matrix surface area from tracer returns and breakthrough curves.

Fracture geometry has been estimated through the use of both conservative tracers and sorbing tracers.[198-199] Conservative tracers are non-reactive with the rock matrix of the reservoir. Conversely, sorbing tracers are more interactive with the rock matrix and tend to accumulate by cation exchange, surface complexation, and other mechanisms. A tracer's reaction to a given reservoir is site-specific; a conservative tracer may behave one way in one reservoir and another way in a different reservoir. For example, fluorescein has shown sorptive and non-sorptive behaviors under varying conditions.[200]

5.2.1 Conservative Tracer Interpretation

Through the use of moment analysis, a technique was developed using conservative tracer data to estimate fracture geometry.[198] Moment analysis, a specific quantitative approach, offers a means of analyzing the temporal behavior of fluid flow to determine swept pore volume, flow geometry, fluid velocity, and an understanding of the nature of reservoir boundaries.[200] To be accurate, moment analysis requires data normalization, correction for thermal decay, deconvolution, extrapolation, and calculation of flow geometry and mean residence time.[187/200] Additionally, moment analysis assumes a steady state injection and extraction rate and that the tracer behaves ideally and is conservative, and therefore does not affect the flow properties of the reservoir or adsorb or volatize along the flow path.[195]

Through the appropriate steps of moment analysis, flow and storage capacities can be directly estimated.[201] By comparing these parameters a sense of the fracture network geometry and degree of heterogeneity can be evaluated and used semi-quantitatively to express the percentage of flow through the fracture network and the percentage of flow from the pore volume.[198] Figure 36 is an example of an F-C curve showing the relationship between flow (F) and storage (C) capacity for a four-fracture network.[198] From the analysis of F-C curves, an estimate, albeit limited in scope, of the fracture area can be made. In combination with independent estimates of fracture length and porosity, F-C curves can give a sense of the area of heat transfer.

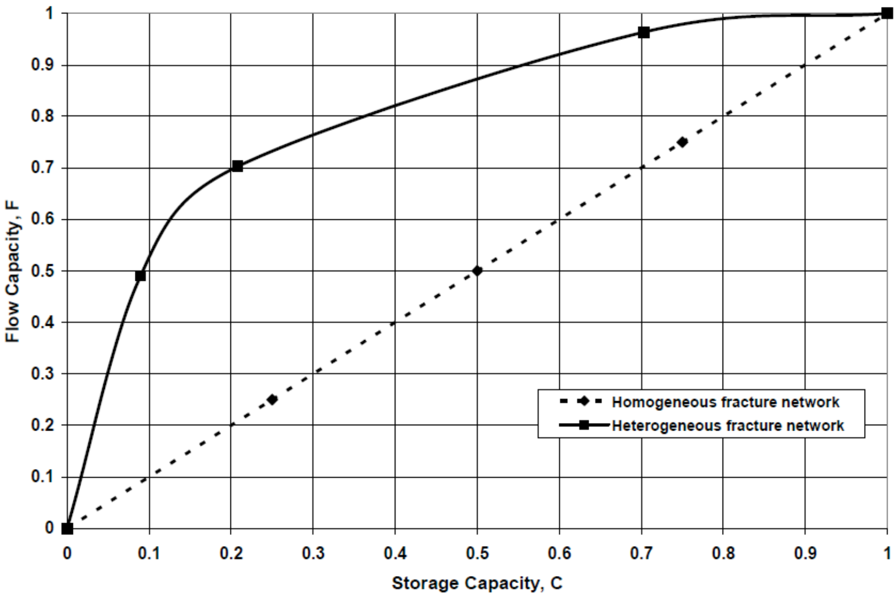


Figure 36. A flow-storage diagram for a four-fracture network

The first curve in Figure 36 is that of a uniform fracture network made up of four fractures. Because the flow and storage are uniform in each fracture, the F-C curve is a straight line. The second curve in the figure is a heterogeneous fracture network (obviously more realistic). The degree of heterogeneity is observed in the degree of departure from the uniform case. In this case, some 70 percent of the flow is from 20 percent of the fracture network pore volume.[198]

5.2.2 Sorbing Tracer Interpretation

In 2005, researchers reported that tracers subject to reversible sorption may be useful in determining the fracture matrix interface area available for heat transfer through analysis of their breakthrough curves (BTC).[199] BTCs represent the relative concentration of fluid plotted versus time. Relative concentration is the ratio of the actual concentration of a fluid (tracer) to the source concentration.

When tracers are controlled for diffusion within a reservoir, the relative concentration reaches zero over time. However, as with all realistic scenarios there will be some level of diffusion and the relative concentrations will begin to approach zero, but will not reach it. This effect seen in BTCs is known as tailing (see Figure 37).[199]

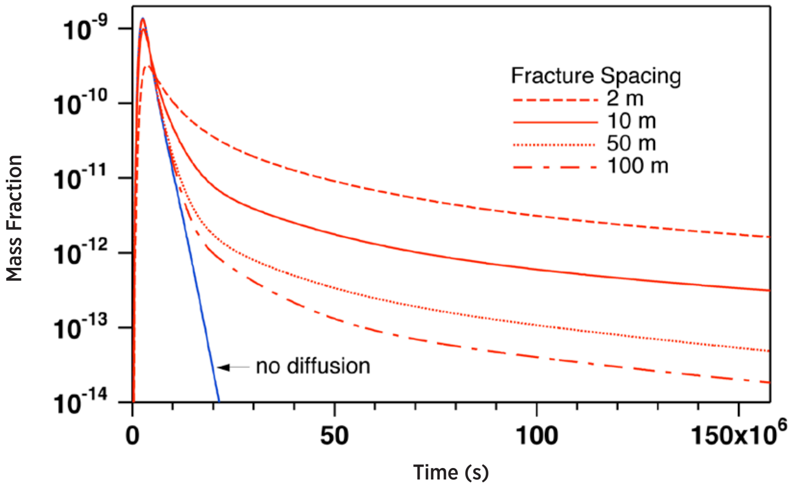


Figure 37. Tracer breakthrough curves for different fracture spacing

The presence of long tails has been identified as the key feature in tracer's BTCs and allows for estimating the fracture-matrix interface area.[199] Naturally, generating BTCs with the use of non-sorbing tracers will show less tailing effects than if sorbing tracers were used. Sorbing tracers are more likely to interact with the rock matrix, enhancing the tailing effect seen. For this reason, analyzing the BTCs of sorbing tracers provides adequate sensitivity for determining the heat transfer area of a geothermal reservoir.[201]

5.2.3 Combined Tracer Interpretation

As previously stated, conservative tracers can offer insight into calculating fracture geometry but further interpretation is restricted by their conservative nature, which prevents the acquisition of information arising from tracer-rock matrix interactions.[202]

The flow velocity of conservative tracers is not impeded as they travel through the reservoir. The velocity of sorbing tracers, however, is hindered relative to the fluid velocity by a factor related to its concentration and temperature.[202] The calculation of mean residence times for both tracers allows for the determination of the value of the retardation factor. As the retardation factor becomes known, the in situ adsorption properties can be inferred. With the known adsorption isotherm and difference in tracer resident times, reservoir engineers can calculate the reservoirs surface area.

5.3 Modeling Parameters: Physical Properties of Geothermal Reservoirs and Fluids

Data on the physical and chemical properties of geothermal reservoirs and fluids are necessary to characterize and assess the size and commercial production potential of a geothermal resource. Important properties include:

- Hydrologic and thermal parameters of the rock formations hosting geothermal systems: Permeability, porosity, relative permeability and capillary pressure; volumetric specific heat and thermal conductivity; and geometric and hydrologic parameters of fractures and fracture networks.
- Geophysical parameters of the rock formations hosting geothermal systems: Electrical conductivity, seismic properties, mechanical parameters such as elastic and shear modulus, Poisson's ratio, and others.
- Thermophysical and chemical properties of the geothermal fluids: Density, viscosity, specific enthalpy as functions of temperature and pressure; diffusion coefficients; partitioning of mass components among different fluid phases; vapor pressure; and surface tension.

Property measurements call for appropriate instrumentation, as well as testing and analytical procedures. Acquiring data in geothermal wells requires downhole tools that can withstand hostile environments of high temperatures, high pressures, and corrosive fluids.

Early efforts by the DOE Geothermal Program focused on assembling and summarizing basic information relevant to geothermal systems, especially fluid properties.[203] Aqueous solubilities of important mineral phases were studied experimentally over a broad range of temperatures.[230] A long-term program of laboratory measurements was undertaken to obtain relative permeabilities and capillary pressures of rock samples from geothermal fields, as well as analogs from different geologic settings.[204-106] Because they play an essential role in most geothermal fields, special efforts were made to gain an understanding of the relative permeability and capillary pressure behavior of fractures.[207-209]

Core drilling projects were undertaken at The Geysers field in California and Awibengkok in Indonesia, and detailed analyses of mineralogy and rock textures were made.[210-211] Permeability, porosity, and capillary pressure data were obtained on metagraywacke specimens from The Geysers.[212] Laboratory measurements of water adsorption at elevated temperatures on geothermal rock specimens were also obtained.[213-215]

Geophysical properties of geothermal rocks were measured on specimens collected at The Geysers and Awibengkok fields.[216-219] Anisotropy and fracture discontinuity effects on seismic wave propagation were used to deduce reservoir-scale fracturing geometry from MEQ data.[220] An electromagnetic logging tool for high temperature applications was developed.[221] Development of instruments capable of withstanding high temperatures was greatly facilitated by transferring technologies developed for internal combustion and jet engines.[222-223]

Laboratory studies quantified the partitioning of chloride compounds between aqueous and gas phases.[224-225] Research sponsored by DOE accomplished the first-ever measurements of two-phase flow in rock fractures with realistic wall roughness[226] and of water adsorption on rock specimens from geothermal fields at actual reservoir temperatures.[214-215] Core measurements of geophysical properties led to the recognition that illite, a common mineral phase in most geothermal reservoirs, plays a controlling role in influencing fundamental geophysical properties.[227]

Data summarized and obtained through this research have provided important inputs to quantitative models of geothermal systems. This has enhanced the acceptance and credibility of models developed for geothermal fields with different physical and chemical characteristics.

5.3.1 Laboratory Studies of Geothermal Reservoir Behavior

DOE has supported the Stanford Geothermal Program since the 1970s. Over the years, a wide variety of research tasks were undertaken by Stanford University professors, research staff, and a legion of graduate students. The Stanford Geothermal Program graduated more than 120 graduate geothermal engineers, many of whom went on to leadership roles in the geothermal industry in the United States and overseas.

While the Stanford Geothermal Program conducted experimental, theoretical, and field studies, its primary focus was laboratory-scale experiments. The program developed specific expertise in the study of multiphase flow in fractured rocks, and was instrumental in producing models for steam-water relative permeability and capillary pressure models for geothermal reservoirs.

For example, a series of projects focused on determining the fundamental flow properties of boiling steam-water transport in fractured geothermal reservoirs to better predict the performance of those reservoirs under exploitation. The properties measuredhave been used by industry in simulation of reservoir performance during project design. Increasing the certainty in forecasting reservoir performance resulted in better development decisions and a reduction in energy recovery costs.

Steam-water relative permeability and capillary pressure are important properties for geothermal reservoir engineering. They have a major influence on the performance of geothermal reservoirs under development. All numerical simulations of geothermal reservoir performance require the input of relative permeability and capillary pressure values, yet actual data on these parameters were not available prior to Stanford's R&D. In addition, in the period preceding Stanford's Geothermal Program steam-water relative permeability and capillary pressure were rather poorly understood primarily due to the great difficulty in conducting experiments in boiling flow since phase transfer makes it hard to account for the individual rates of flow. Stanford developed methods to measure relative permeability and capillary pressure in actual geothermal rock that is low permeability and fractured.

The Stanford Geothermal Program began measuring steam-water relative permeability using bench-scale experiments in the 1970s. The difficulty of accounting for individual flow rates of the steam and water phases, and in situ saturation, was addressed in a number of ways, such as the development of a capacitance probe. Nonetheless, uncertainties in the measurements placed the experiments on hold until a more accurate way of determining steam saturation could be found. This capability was realized in the 1990s with the acquisition of an X-ray computer tomography (CT) scanner.

Using the steady-state X-ray CT method, Stanford researchers measured steam-water relative permeability and capillary pressure in rock with permeability above 1 md (10^{-13} cm^2). The in situ fluid saturation was obtained simultaneously. For geothermal rock with permeability smaller than 1 md (10^{-13} cm^2), the steady-state CT method still worked, but an extremely long time was required to conduct the experiments.

A method to overcome this difficulty involved measuring steam-water relative permeability in fracture models. The apparatus is shown in Figure 38. Distributions of pressure and temperature in the fracture model were measured. Saturation could be measured by digital video analysis. The flow rates of steam and water were measured using an optical device installed at the outlet of the model. Finally, the steam-water relative permeabilities in the fracture were calculated using Darcy's Law.[228]

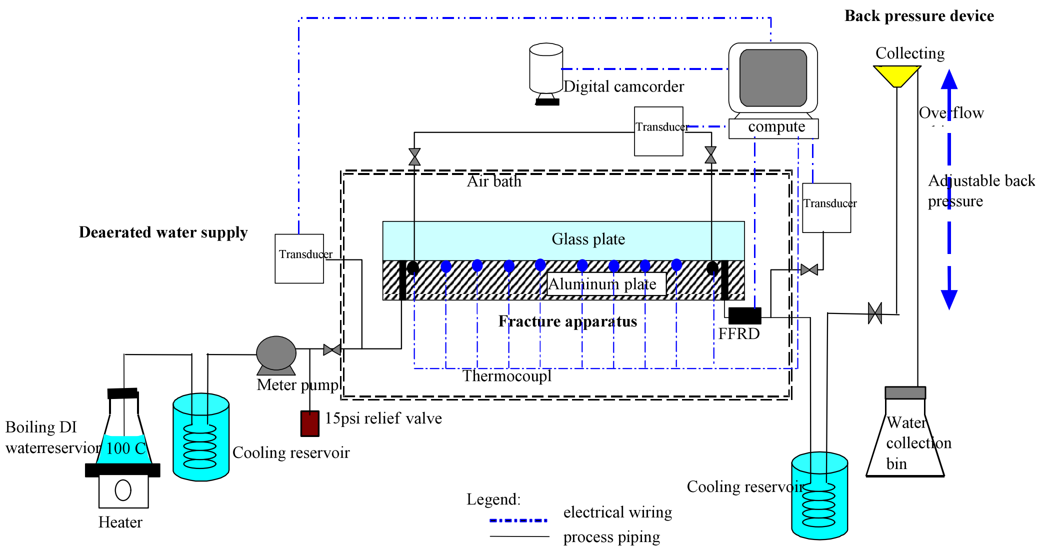


Figure 38. Process flow diagram for steam-water experiment

Stanford researchers conducted experiments in smooth-walled, homogeneously rough-walled (HR) and randomly rough-walled (RR) fractures. The experimental investigation of steam-water flow showed that steam-water flow behavior in fractures is different from that of air-water flow in aspects of relative permeability, flow structure, and residual-immobile phase saturations. From the fractures studied, most steam phase relative permeabilities surpassed air phase relative permeabilities, which is consistent with theory and most earlier studies in porous media. The generation of nucleated steam clusters was one distinct feature observed during steam-water flow in the rough-walled fractures. The clusters appeared to explain the similar relative permeability behavior in porous media obtained by earlier investigators.

By characterizing these immobile steam clusters using nucleated steam saturation (S_{gn}), Stanford incorporated the S_g in the previously suggested tortuous-channel model for air-water flow. This modified tortuous-channel model (MTCM) described not only the steam-water relative permeabilities from three fractures, but also results from earlier investigations for consolidated and unconsolidated porous media, as shown in Figure 39.[229]

The MTCM relative permeability function is expressed as:

$$k_{rw} = (1\text{-}S_{gn})(0.74S_w^{*2} + 0.26S_w^{*}) \qquad (1)$$

$$k_{rw} = 0.43S_g^{*2} + 0.38S_g^{*2} + 0.19S_g^{*} \qquad (2)$$

where S_g^* is normalized gas saturation defined as

$$S_g^* = \frac{1 - S_w - S_{gn}}{1 - S_{wr} - S_{gn}} \qquad (3)$$

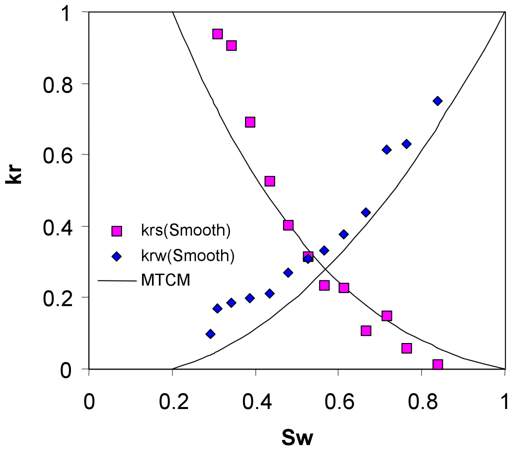


Figure 39. Interpretations of steam-water relative permeabilities using modified tortuous-channel model (MTCM): smooth-walled fracture data

Stanford's contributions to the understanding of flow in fractured rocks and multiphase flow of boiling fluids has enabled the more robust forecasting of geothermal reservoir performance by the provision of better reservoir models. The improved understanding of flow in fractures is also of central importance to the future application of EGS.

5.3.2 Fluid Chemistry: Theory, Laboratory, and Field Verification

In the early 1980s, DOE recognized that the economical use of geothermal resources required an accurate understanding of the chemical behavior of geothermal fluids and how these fluids interacted with reservoir rocks and minerals. Mineral precipitation (scaling) within production and injection well bores and surface equipment can have very costly effects on power plant operations. Mineral precipitation and dissolution along fluid flow paths in the geothermal reservoir can significantly alter reservoir porosity and impedance. Chemical models of fluid behavior can predict possible problems related to the extraction of energy from a geothermal reservoir. The accuracy of a particular model greatly depends on the validity and accuracy of the chemical equations-of-state (EOS) that drive model predictions.

The fluid chemistry R&D component of DOE's Geothermal Program looked to laboratory studies and model development for predicting geochemical and isotopic behavior in reservoirs under production. The primary objectives of fluid chemistry R&D were to:

- Develop thermodynamic models relevant to the pressure, temperature, and solute concentrations encountered in geothermal systems to facilitate the prediction of scale formation, phase equilibria, gas breakout, pH, solid-gas-liquid partitioning, and interaction of solutes and solute isotopes.
- Develop EOS and molecular simulations of the thermodynamics of geothermal fluids to support the chemical aspects of reservoir engineering studies and the history and evolution of geothermal reservoirs.
- Develop a more thorough understanding of the solubility and speciation of complex cation solutes and minerals—particularly the important aluminum-bearing phases that dominate crustal mineralogy.
- Incorporate thermodynamic data and EOS representations into publically available user-friendly software.

From the late 1980s on, Oak Ridge National Laboratory (ORNL) and the University of California at San Diego (UCSD) conducted geochemical and isotopic research that provided the input data for much of the modeling capability available to the geothermal community.

5.3.3 Physical Chemistry of Geothermal Systems

The Physical Chemistry of Geothermal Systems program at ORNL focused on three areas of research:

1. Solubility and speciation of aluminum under geothermal conditions,
2. Thermodynamics and volatility of HCl in geothermal brines during brine dry out assuming conditions relevant to The Geysers geothermal field, and
3. Partitioning of the isotopes of carbon, oxygen and hydrogen in brine-gas-mineral systems relevant to geothermal resources.

SOLUBILITY AND SPECIATION OF ALUMINUM UNDER GEOTHERMAL CONDITIONS

Aluminum is the third most abundant element in the Earth's crust, after oxygen and silicon. Aluminosilicates are the predominant mineral phases encountered in geothermal systems. Many geochemical processes in geothermal systems are strongly influenced by fluid buffering and permeability changes driven by the interaction of aluminum silicates, oxides, and hydroxides with circulating fluids. Reliable geothermal models are needed to predict these processes.

Although the thermodynamics of many aluminous minerals are relatively well known, the aqueous chemistry of dissolved aluminum is a controversial subject, due primarily to the slow kinetics of dissolution and precipitation of aluminous phases, the persistence of polymeric species in aqueous solutions, and the very low equilibrium solubility of aluminum minerals. Furthermore, the small ionic radius and high charge of Al^{3+} results in a variety of hydrolysis and complexation reactions, which can alter solubility by many orders of magnitude.

Experimental work provided the thermodynamic properties and corresponding activity coefficients of Al(OH)y3-y ions, their formation constants, and their complexation by organic and inorganic ligands. The experimental studies also determined the solubility of gibbsite, $Al(OH)_3$, and potentiometric measurements of the formation constants of $Al(OH)_{2^+}$ over a wide range of temperatures and salinities.[203]

THERMODYNAMICS AND VOLATILITY OF HCL IN GEOTHERMAL BRINES

Corrosive solutes in geothermal fluids can limit or prevent economic production from relatively high temperature geothermal resources. The classic case is the high temperature wells (over 300oC [572°F]) in the vapor-dominated resource of the northwest Geysers steam field. These wells produced very high levels of chloride (over 100 parts per million [ppm] in some cases) at the well head. The chloride-bearing vapor was extremely corrosive to piping and well casings. In severe cases, wells in the northwest Geysers were abandoned, resulting in the loss of production from a significant fraction of the field. Furthermore, the potential for production of acidic vapors in the remaining wells at The Geysers due to continued production was of great concern for the long-term viability of the resource.

The composition of coexisting liquid and vapor phases were determined for brines containing NaCl and either HCl or NaOH at temperatures from 250°C to 350°C [482°F to 662°F]. Thermodynamic partitioning constants for NaCl were determined. This enabled calculation of the HCl and NaCl concentrations in steam produced from various brines as a function of temperature and brine composition, leading to mitigation strategies for corrosive HCl bearing vapor applicable to The Geysers and similar vapor dominated systems.[231]

PARTITIONING OF THE ISOTOPES OF CARBON, OXYGEN AND HYDROGEN IN BRINE-GAS-MINERAL SYSTEMS

The time-temperature history of geothermal systems, the sources and fluxes of fluids, the extent of boiling and mineral deposition, and the temporal relationship among alteration minerals can be constrained by the isotopic compositions of oxygen, hydrogen, carbon, and other light elements which partition in a mass-dependent manner as a function of temperature and the bonding characteristics of individual phases. This research effort:

- Experimentally defined the partitioning of isotopes between geothermal waters and other phases (i.e., steam, gas, and secondary minerals) as a function of temperature, pressure, and the concentration of dissolved salts; and
- Developed models to predict the evolution of the isotopic composition of geothermal fluids and minerals under various physical and chemical conditions.

Modeling technologies were developed that increased the understanding of geothermal reservoir chemistry and chemistry-related energy production processes. Direct interpretation of these processes in terms of experimental data was often prevented by the varying and complex temperatures (T), pressures (P), and fluid compositions (X) encountered in many geochemical applications. ORNL showed—by using physical chemistry theory, equilibrium thermodynamics, and free energy descriptions—that chemical models could describe behavior in different regions of TPX space, as well as with the very high PT chemistry of deep resources that is difficult to measure with traditional experimental methods. A mathematical EOS framework and equilibrium-solving algorithms were developed to treat complex equilibria involving phase selection among many solution phases, as well as parameterization procedures that allow accurate description of the system's thermodynamics via its free energy.[232]

5.3.4 Modeling Geothermal Reservoir Chemistry and Chemistry-Related Energy Production

With funding from DOE's Geothermal Program and other agencies including the National Science Foundation (NSF) and the DOE Office of Basic Energy Sciences (OBES), UCSD researchers developed modeling technologies that increased the understanding of geothermal reservoir chemistry and chemistry-related energy production processes.[233] The group at UCSD focused on four areas of research:

1. Thermodynamic models using Pitzer-specific interaction equations,
2. High-temperature and pressure equations of state and solubility models,
3. Equation-of-state compressible mixtures near and above the critical temperature of water, and
4. Solubility models for systems with phase coexistence and temperatures below the critical temperature of water.

THERMODYNAMIC MODELS USING PITZER-SPECIFIC INTERACTION EQUATIONS

For typical geothermal operations (T < 300°C [572°F]; P ≈ 1 atmosphere) the largest variation of the free energy of hydrothermal fluids, which drives chemical evolution of fluids, comes from changes in temperature and solute concentrations (X).

Successful EOS models for these systems must be able to accurately describe changes in the dissociation state of solutes, as well as efficiently treat important mixing effects and solid-liquid-gas equilibria to high fluid concentration as a function of temperature. In order to provide the highest accuracy, the UCSD group tailored its selection of EOS to reflect the important properties of each phase in this TP range (0°C to 250°C [32°F to 482°F], pressures along the saturation line).

Solid phases were described as pure or by using Margules solution models. An ideal mixture or mixing EOS was used for the vapor phase. For the aqueous phase, the activities were based on the solution free energy equation introduced by Pitzer. Because this approach used the solution free energy, various measured properties (e.g., osmotic, electromagnetic field [emf], solvent vapor pressure, heats of solution) were consistent and could all be used as constraints in evaluating the parameters describing the free energy. Only data for systems up to ternary order were required to determine the parameters for prediction in systems of much higher complexity. The model therefore provided a means to extrapolate thermodynamic measurements taken in binary and ternary systems to the much more complex systems encountered in geothermal and other earth processes.

UCSD created an extensive software library that enables simultaneous fits to the wide range of data available for a particular system. In addition, they developed a method of optimizing the free energy of the total system that was robust and capable of selecting the optimal phase assemblage from a variety of possibilities, including the coexistence of multiple pure and solid solution phases. All these capabilities were required to correctly predict phase coexistence in natural environments that include multiple solution and pure solid phases (e.g., Na/K-feldspar solid solutions-evaporite/carbonate minerals-aqueous solution-vapor).

Considerable progress was made (see Table 12) in completing Pitzer-type models for chemical systems relavant to geothermal fluids that can calculate solution activities and solid-liquid-gas equilibria to high solution concentration in the 0°C to 250°C (32°F to 482°F) temperature range, for pressures along the saturation line. These models allowed the prediction of mineral solubility, mineral assemblage stability, and acid-base properties in the evaporite, carbonate, silicate, and aluminosilicate systems found throughout the Earth's crust—an ability that is critical to understanding important rock-water and energy production processes affecting fluid flow in geothermal systems (e.g., mineral scaling, rock permeability changes, fluid mixing, and the onset of two phase flow).

Table 12. Status of U.S. Department of Energy-Supported Pitzer Model Development

Models of Solution Activities and Solid-Liquid Equlibria	Comments
(1) Model of H-Na-K-Ca-Mg-OH-Cl-HSO_4-SO_4- CO_2-HCO_3-CO_3, -H_2O-CO_2(gas) 25°C	Harvie et al. (1984)
(2) Model of Na-K-Ca-Mg-Cl-SO_4-CO_2-$B(OH)_4$-H_2O solution activities and solid-liquid equilibria, 0°C - 250°C	Felmy and Weare (1986)
(3) Model of Na-Ca-Cl-SO_4-H_2O solution activities and solid-liquid equilibria, 0°C - 250°C	Möller (1988)
(4) Model of Na-K-Ca-Cl-SO_4-H_2O solution activities and solid-liquid equilibria, 0°C - 250°C	Greenberg and Möller (1989)
(5) Model of Na-K-Ca-Mg-Cl-SO_4-H_2O solution activities and solid-liquid equilibria, T < 0°C.	Spencer et al. (1990)
(6) Model of Na-K-Ca-Mg-Cl-SO_4-H_2O solution activities and solid-liquid equilibria, 0°C - 250°C.	Preliminary model of magnesium interactions, unpublished
(7,8) Model of acid/base H-Na-K-Ca-OH-Cl-HSO_4-SO_4-H_2O solution activities and solid-liquid equilibria,, 0°-250°C.	Christov, Möller (2004a,b)
(9) SiO_2, H_4SiO_4, H_3SiO_4 interactions added to model 5 above.	unpublished.
(10) CO_2-HCO_3-CO_3, interactions added to model #4.	Na,K interactions completed; manu-script in preparation; Preliminary addition of Ca interactions.
(11) Acid aluminum interactions in H-Al-Na-K-Cl-H_2O system, 0-120°C	Christov and Möller 2007 accepted for publication
(12) Aluminum hydrolysis model of H-Na-Al-Cl-OH-$Al(OH)^2$+-$Al(OH)_{2+}$-$Al(OH)_3°$- $Al(OH)_4$ H_2O system, 0-250°C	Manuscript in preparation
(13) Aluminum sulfate model of H-Al-Na-HSO_4-SO_4-H_2O, 25°C	Preliminary model complete

The solution activities of aqueous species containing aluminum and silica play a central role in controlling the solubility of aluminosilicate minerals, which constitute two-thirds of the minerals in the earth's crust commonly as feldspars. The complex aqueous chemistry of aluminum and its low solubility (particularly for aluminum in the near neutral pH region common to natural systems) makes model development difficult (Figure 40). Concordant with experimental work conducted at ORNL (see "The Solubility and Speciation of Aluminum under Geothermal Conditions" above), and coupled with existing literature data, it was possible to characterize the thermodynamics of Al3+ and its hydrolysis products. Figure 40 illustrates the predicted distribution of aqueous aluminum species as a function of pH and temperature in pure water at 90°C (194°F). Ultimately, this model was expanded to include the aqueous aluminum-sulfate system.

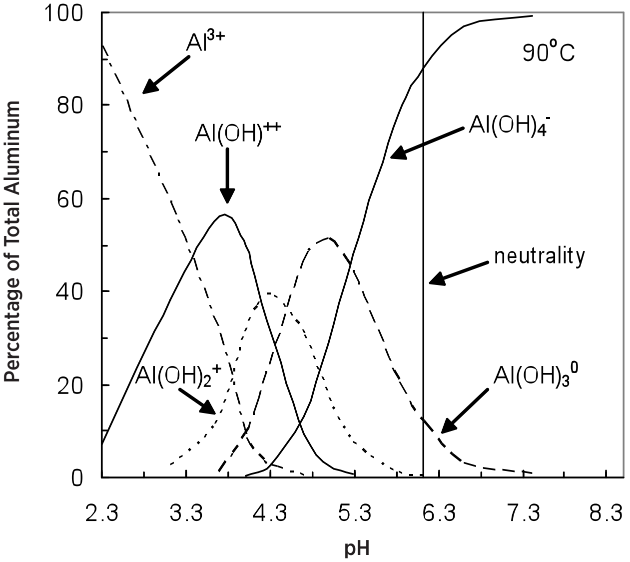


Figure 40. The prediction of the distribution of aqueous aluminum species as a function of pH and temperature in pure water at 90°C (194°F)

HIGH-TEMPERATURE AND PRESSURE EQUATIONS OF STATE AND SOLUBILITY MODELS

To develop high PT resources and low permeability reservoirs, the chemistry and physical properties of the phases in the rock formations hosting the geothermal systems must be known. However, there is little, if any, experimental data for model parameterization. To accurately reproduce the thermodynamic properties of these systems, the UCSD group developed a new EOS modeling phenomenology capable of describing systems with compressible phases and multiple phase geothermal processes, such as flashing.

Molecular-level modeling approaches, such as molecular dynamic and Monte Carlo simulations were used to assist model development by generating difficult to obtain or unavailable experimentally PVTx data (e.g., very high PT conditions). (PVTx is an EOS-based program for simulating PVT experiments used in simple process applications.) UCSD also explored the possibility of developing descriptions of geothermal fluid chemistry more closely related to first-principle theories. Such descriptions would have better interpolation and extrapolation properties and require few if any experimental data for model construction.[234-237]

EQUATION-OF-STATE COMPRESSIBLE MIXTURES NEAR AND ABOVE THE CRITICAL TEMPERATURE OF WATER

For compressible mixtures near and above the critical temperature of water (i.e., 373°C [703°F]) the most commonly applied variables are usually temperature, volume (or density), and composition. The appropriate thermodynamic function on which to base an EOS is the molar Helmholtz free energy. All other properties needed to predict behavior (e.g., enthalpy) can be derived from this function by the appropriate derivatives.

To provide optimal interpolation and extrapolation of mixing properties, the functional form of the free energy must be based on a reasonably accurate molecular-level description of the system. Thermodynamic perturbation theory was used to develop a molecular framework for generating an EOS. To achieve the necessary accuracy for quantitative description, empirical corrections were added to the EOS and this theory was successfully applied to build quantitative models of brine-insoluble gas mixtures. An example of the accuracy that can be obtained from such an approach is given in Figure 41. Note the excellent agreement of the EOS with data below the critical temperature.

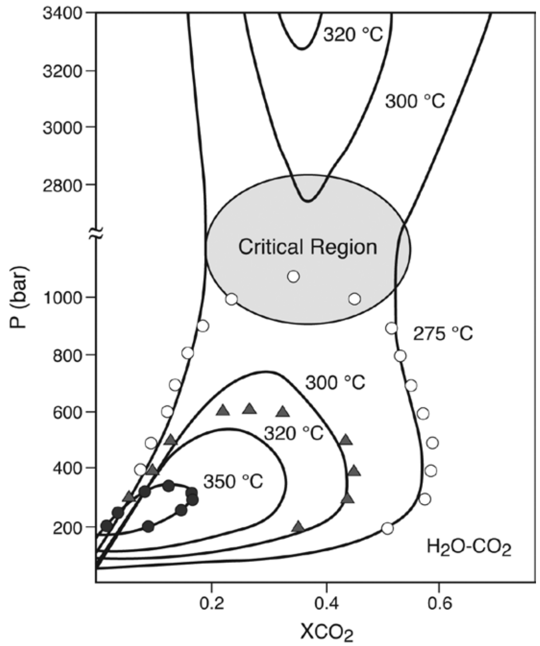


Figure 41. Pressure-composition predictions of EOS for the CO_2-H_2O system

(Courtesy of John H. Weare)

SOLUBILITY MODELS FOR SYSTEMS WITH PHASE COEXISTENCE AND TEMPERATURES BELOW THE CRITICAL TEMPERATURE OF WATER

Systems containing a significant amount of water and insoluble gas (e.g., geothermal fluids [H_2O+CO_2 mixtures]), and at temperatures below the critical point of water (373°C [703°F]) will separate into a dense fluid (mostly water) and a vapor phase (slightly soluble gases and water vapor). There often are other solutes in the systems (e.g., NaCl) that exist only in the liquid phase. For this kind of system, a generalization of Henry's Law was designed that is applicable to high T and P, and to liquid mixtures.

For low-pressure systems (total pressure less than 10 bar), the gas phase can be described by an ideal gas EOS. For higher pressure, an EOS or table must be used to calculate the fugacity of the species in the gas phase. The liquid density with solutes phase (e.g., a geothermal brine) is conveniently described by the Pitzer approach (see above). The solubility of the gas phase in the brine and the water in the gas phase may then be calculated by equating the free energies of the separate systems.

AVAILABILITY OF MODELS

The technology developed by the UCSD group was posted on an interactive website for public access and use.[238] Three packages are available:

1. TEQUIL—rock/water/gas interactions, such as scaling, flashing, and reservoir chemistry, as a function of composition to high solution concentration for temperatures below 300°C (572°F);
2. GEOFLUIDS—multiple phase processes, such as flashing and miscibility, to high T, P supercritical conditions; and
3. GEOHEAT—heat characteristics such as enthalpies of complex mixtures.

The website is accessed by users nationally and internationally. Consequently, the chemical models—which have wide application to many important problems (e.g., scaling prediction in petroleum production systems, stripping towers for mineral production processes, nuclear waste storage, CO_2 sequestration strategies, global warming)—have been incorporated into many model packages both in the United States and abroad (e.g., TEQUIL, EQ3/6NR, PHREEQ, GMIN, REACT, FLOTRAN, FREEZCHEM, ESP, TOUGHREACT [see Section 4.4.2], and SCAPE2).

6.0 Enhanced Geothermal Systems

In the summer of 1995, DOE decided to terminate the HDR Program, in particular to cease all operations at the LANL Fenton Hill site. The perception at the time was that Fenton Hill had reached a point of diminishing returns relative to the funding required to run the site. The HDR Program was the longest-lived DOE R&D program in geothermal energy, dating back to 1972 and the AEC's Plowshare Program. However, DOE recognized the national benefit of extracting heat economically from water-deficient rocks and determined that future work on heat extraction technology was desirable. Primary drivers for this determination were the exceptional size and geographic extent of the hot dry rock resource base, the perceived limitations in the availability of commercial hydrothermal resources, and the continued interest in HDR technology development by other countries.

DOE also determined that future work would not be laboratory-based but rather would involve the active participation of the U.S. geothermal industry. Subsequently, at the Department's request the Geothermal Energy Association (GEA) held a workshop in December 1995 at the offices of Unocal Geothermal Corporation in Santa Rosa, California. A broad cross section of the geothermal community attended. Several key findings and recommendations emerged from the workshop:

- DOE's decision to terminate the Fenton Hill Project was correct.
- The HDR resource was too large to ignore.
- The HDR resource could play an important role in the future of the geothermal industry.
- DOE should continue to sponsor R&D on HDR resources with industry's active involvement.
- Subsequent R&D would likely have near-term benefits for hydrothermal technology.
- The term "hot dry rock" should be abandoned in favor of a more broadly descriptive terminology.

The results of the Santa Rosa workshop were implemented with a DOE solicitation in 1997 for industry partners to assist in the planning and management of a new program in "hot dry rock." A contract was awarded to an industry team composed of Princeton Energy Resources International, LLC (PERI) and GeothermEx, Inc. The new industry team began a collaborative process with other U.S. geothermal industry representatives. One of the first recommendations of this group was adoption of the term "enhanced geothermal systems" to replace "hot dry rock." The key word "enhanced" in the new phrasing implied an improvement over a natural geothermal system using enhancement techniques to increase permeability and/or fluid content. EGS was officially introduced to the U.S. geothermal community at the DOE Annual Geothermal Program Review in the spring of 1998.

Initially, EGS was defined along resource lines to cover the continuum of rock permeabilities that occur in nature. By this definition HDR was considered the impermeable end member of the continuum while highly permeable hydrothermal resources represented the opposite end member. Resources falling between the end members were targeted as the focus of the new EGS initiative.

As time passed, EGS became both a resource-oriented term and a descriptor of the technology required to improve noncommercial resources. With some minor variations, DOE eventually adopted the following definition:

> *"Enhanced Geothermal Systems are engineered reservoirs created to extract economical amounts of heat from unproductive geothermal resources."*

Use of the word "engineered" implied that the application of some enhancement technology was required for the achievement of commercially productive reservoirs. Thus the EGS initiative evolved into a technology development program, apart from resource characterizations which had been the hallmark of other DOE resource-based programs such as geopressured-geothermal and the original HDR Program.

Over the next few years, EGS largely displaced HDR around the world as the term of art for making unproductive reservoirs productive. Briefly, the term, "hot wet rock" or HWR, was used in some European countries and Japan in recognition of the permeability continuum. A watershed for the nomenclature was reached in 2003 when the ExCo of the IEA/GIA renamed the Agreement's Hot Dry Rock task annex, "Enhanced Geothermal Systems." Afterwards, EGS quickly became a universally accepted term within the international geothermal community.

In many respects, EGS differs little from HDR (Figure 42).[239] A well drilled into hot rock with low permeability (and thus low fluid productivity) would be treated (e.g., by hydraulic stimulation) to create a network of permeable fractures. A second well would be drilled to intersect the fractured rock volume, creating a circulation loop. Water pumped down one well would become heated as it flowed through the fracture network, before being produced through the other well in the loop. After the heat energy in the water was extracted at the surface for electric power production or some other application, the water could be returned to the first well to repeat the process. The EGS reservoir could be expanded and replicated with multiple wells and circulation loops. Thus, reservoir enhancement techniques are applicable across a broader spectrum of resources than just the low-permeability HDR end-member. Further, EGS embraced a broader range of enhancement techniques, including those adapted from the oil and gas industry, which considered rocks of variable permeabilities and lithologies.

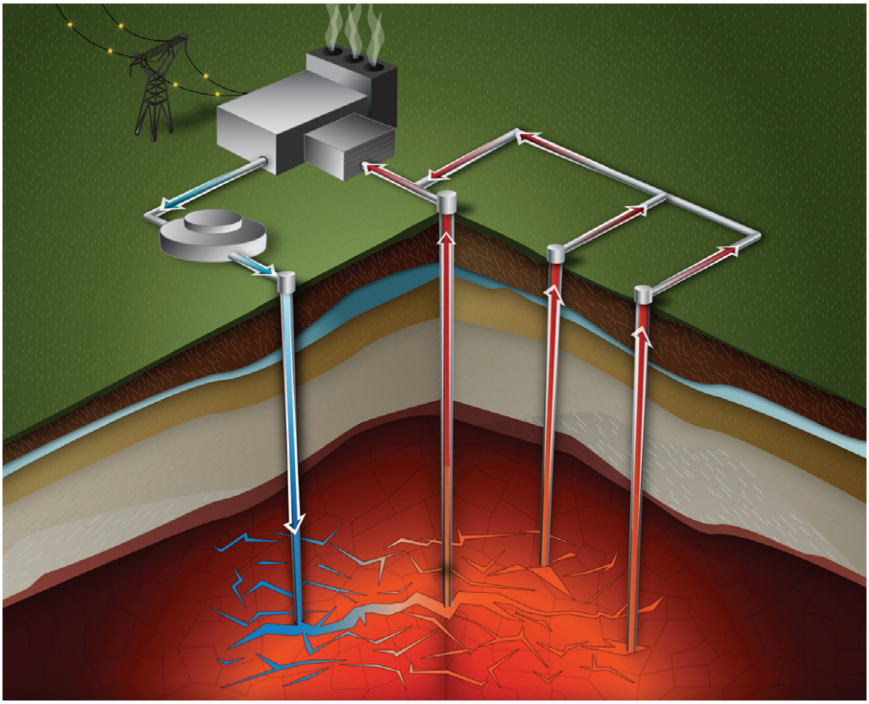


Figure 42. Enhanced Geothermal System Concept

EGS reservoirs have certain intrinsic properties that make them an attractive energy option. Since only hot rock is required to create an EGS, there is substantial flexibility in siting the wells and surface facilities. Thus, the project could be brought closer to the market access point, such as a utility's substation or transmission line. Similarly, there is flexibility in the size and number of reservoir loops so that a project at a given site can be sized to fit the market's needs. EGS can be used to increase the productivity of a natural hydrothermal field by mining the heat from low-permeability regions within and/or around the field, thereby increasing the total value of the owner's investment. Finally, since they are closed loop systems, EGS has little or no emissions to the environment.

Among the early activities of the newly formed EGS program was an evaluation of the techniques and tools developed during the course of the Fenton Hill Project, and the major lessons learned from the project itself.[240-242] In addition, a national collaborative committee—comprised mainly of U.S. geothermal companies—was formed to evaluate the barriers to EGS development and identify technologies that could be used across the spectrum of geothermal resources. A series of workshops and meetings were held in 1998–2000 that suggested avenues of investigation that would both involve the U.S. geothermal industry and advance the science and engineering of EGS. This work resulted in an "EGS Roadmap" to guide management of the EGS program.[243-244]

In 2000, after the initial formative work by PERI, DOE began actively funding the new EGS program and adopted a two-pronged implementation strategy:

1. Conduct R&D on EGS science and technology, mainly related to permeability enhancement.

2. Apply EGS technologies in partnership with industry at selected field demonstration sites.

Both strategic elements were initiated with open calls for proposals in 2000, 2002, and 2004. Research projects resulting from the first calls for proposals, as well as work at the national laboratories, are summarized in the following sections. (Note: Some of the projects were still ongoing or had just begun at the end of 2006. The projects and results reported here should therefore be considered representative of the work undertaken in EGS rather than a complete accounting.)

6.1 Science and Technology Research Projects

6.1.1 Petrophysical Properties of Fractures

This LLNL project combined laboratory experiments with computer modeling to characterize the hydraulic and geochemical properties of various rock samples. Sample characterizations are important to EGS because sustaining fracture permeability depends on variables such as rock type, fluid chemistry, temperature, local stress field, fracture strain rate, and the proximity of natural fractures to the well bore.

Laboratory experiments allowed the LLNL research team to observe the evolution of permeability during injection at geothermal pressures and temperatures and to determine the geochemical attributes that affect induced fractures in geothermal environments. Fluid flow experiments used quartz monzonite core retrieved from depths of about 1 kilometer (0.6 miles) at the Desert Peak East EGS site in Churchill County, Nevada. Experiments were performed at the representative conditions of potential EGS systems: confining pressure of 5.5 MPa, pore pressures of 1.38 MPa or 2.07 MPa, and temperatures of 167°C to 169°C (333°F to 336°F).

For these experiments, the injection fluid was saline water representative of spent geothermal brine at Desert Peak. Flow through an artificial fracture was monitored for periods up to several months. During that time, flow rates were maintained between 0.02 to 0.005 milliliters per minute (ml/min), and changes in the differential pore pressure were recorded. In addition, the effective hydraulic aperture was calculated from the variable flow rate data.

Differential pressure measurements indicated that fracture permeability in the Desert Peak samples responded to fluid injection. The pressure difference during constant flow at 166°C approximately doubled in 45 days (Figure 43). Accordingly, the calculated effective hydraulic aperture decreased in all experiments as a result of reactive transport. In some cases, the effective hydraulic aperture decreased by half the starting width.

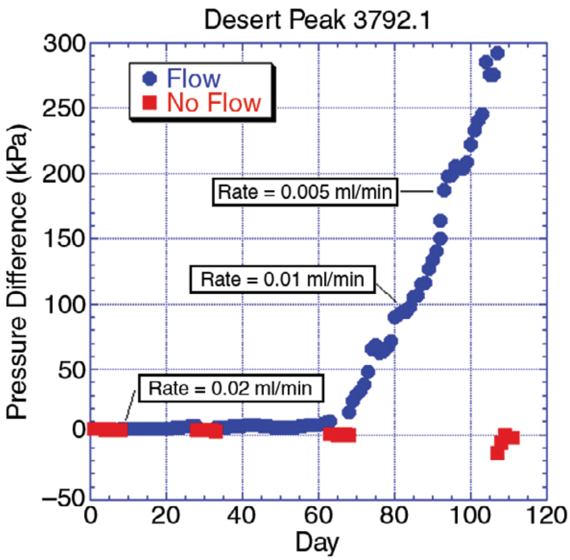


Figure 43. Evolution of fracture permeability observed on the Desert Peak core DP3972.1. Differential pressure increased over the course of the experiment. Flow rates were reduced in the latter stages of the experiment so that pressure remained within the instrumentation's measurement range.

The LLNL research team used profilometry to measure quantitative changes during the flow experiments. As shown in Figure 44, channels developed during the experiments, and the overall fracture roughness decreased. In addition, more small-wavelength variation was observed in the pre-flow fracture surfaces than in the post-flow surface. Figure 45 shows the two-dimensional (2-D) stream tubes calculated by tracking particles through the velocity field or by directly solving the 2-D stream function.

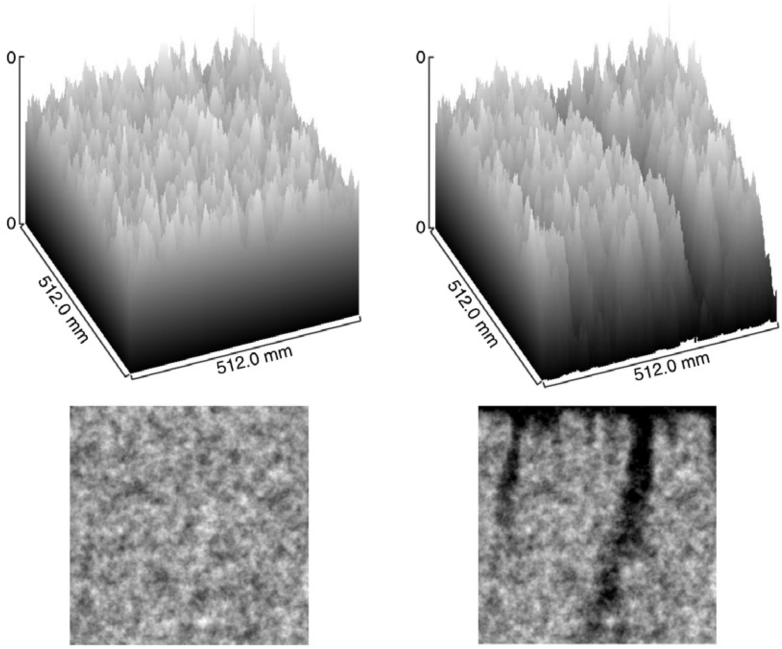


Figure 44. Surface profiles of the fracture surface (a) before and (b) after the induced flow. In the three-dimensional representations, the scale is exaggerated vertically. Note the channel development in the post-flow image.

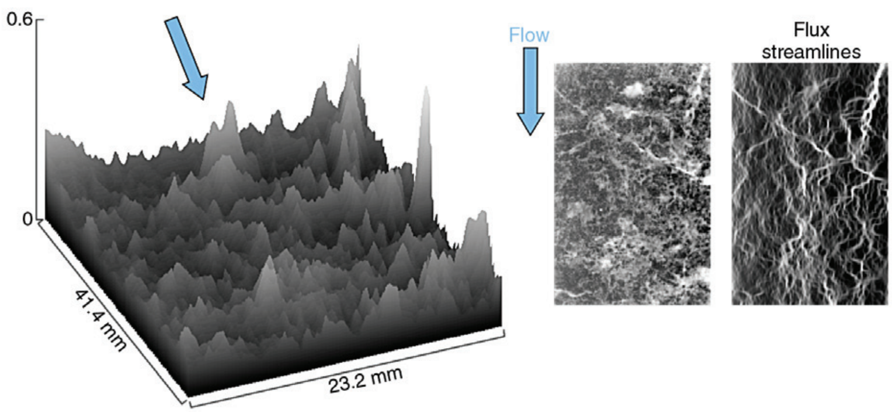


Figure 45. Calculated flow using 2-D finite difference discretization of Reynolds equation in measured aperture.

These experiments increased understanding of the effects of temperature and injection fluid chemistry on changing fracture permeability. Statistical analysis of fracture apertures for two core samples demonstrated that fractures with similar aperture distribution and spatial correlation would have different rates of permeability evolution depending on fluid composition and flow rate. Results from hydraulic modeling indicated that variations in particle residence times would affect local geochemical reaction rates.[245]

6.1.2 Stress- and Chemistry-Mediated Permeability Enhancement/ Degradation in Stimulated Critically-Stressed Fractures

Researchers at Pennsylvania State University (PSU) investigated the interactions between stress and chemistry in controlling the evolution of permeability in stimulated fractured reservoirs through an integrated program of experimentation and modeling. Flow-through experiments on natural and artificial fractures in diorite from Coso examined the evolution of permeability under paths of mean and deviatoric stresses, including the role of dissolution and precipitation.

A long-term circulation test was conducted on a calcite-filled fracture in diorite from the Coso Geothermal Field, California. Water at 20°C (68°F), then 60°C (140°F), and then 90°C (194°F) was circulated through a fracture under a near constant effective stress of 13 MPa. Through the initial stages of the test, at 20°C, the fracture aperture dropped from an initial mean hydraulic aperture of 30 μm to 0.6 μm in the first 500 hours, before reaching a steady state. This corresponded to a net reduction of 4 orders of magnitude through the initial duration of the experiment, and under constant stress. As temperature was increased, the average aperture further reduced, but a periodic change in aperture and hydraulic impedance was recorded under conditions of constant stress, temperature and pressure-controlled flow rate. The peak cyclic flow rate climbed rapidly to about 20 times the steadyrate, with a period of 6,000 minutes. This behavior was interpreted as periodic clogging and removal of mineral mass from the constricted and brecciated end of the sample. As the temperature was increased to 90°C, the flow rate, a proxy for hydraulic aperture, continued to decrease, ultimately reaching a final aperture of 1 μm at 0.03 cc/min. This low magnitude of ultimate permeability, despite visible open voids within the calcite vein, was strongly conditioned by the evolving aqueous chemistry of the sample.

The evolution of permeability in fractured rock as a function of effective normal stress, shear displacement, and damage remains a complex issue. PSU performed experiments in which rock surfaces were subject to direct shear under controlled pore pressure and true triaxial stress conditions while permeability was continuously monitored via flow parallel to the shear direction. Shear tests were performed in a pressure vessel under drained conditions on samples of novaculite (Arkansas) and diorite (Coso geothermal field, California). The sample pairs were sheared to 18 millimeters (mm) of total displacement at 5 μm/sec, under room temperature conditions, and with effective normal stresses on the shear plane ranging from 5 to 20 MPa. Permeability evolution was measured throughout shearing via flow of distilled water from an upstream reservoir discharging downstream of the sample at atmospheric pressure. For diorite and novaculite, initial (pre-shear) fracture permeability was 0.5 to 1×10^{-14} m^2, and largely independent of the applied effective normal stresses. These permeabilities correspond to equivalent hydraulic apertures of 15 to 20 µm. Because of the progressive formation of gouge during shear, the post-shear permeability of the diorite fracture dropped to a final steady value of 0.5×10^{-17} m^2. The behavior was similar in novaculite, but the final permeability of 0.5×10^{-16} m^2 is obtained only at an effective normal stress of 20 MPa.

PSU coupled the thermal (T), hydrologic (H), and chemical precipitation/dissolution (C) capabilities of the TOUGHREACT model with the mechanical (M) framework of FLAC^{3D} to examine THMC processes in deformable, fractured porous media. Analytical comparisons confirmed the capability of the model to represent the rapid, undrained response of the fluid-mechanical system to mechanical loading. PSU examined a prototypical EGS for the temporal arrival of hydro-mechanical versus thermo-mechanical versus chemical changes in fluid transmission as cold water (70°C [158°F]) was injected at geochemical disequilibrium within a heated reservoir (275°C [527°F]).

For an injection-withdrawal doublet separated by 670 m, the results demonstrated: 1) the strong influence of mechanical effects in the short term (several days); 2) the influence of thermal effects in the intermediate term (less than 1 month); and 3) the long-term (greater than 1 year) influence of chemical effects, especially close to the injection well. In most of the reservoir, cooling enhances permeability and increases fluid circulation under pressure-drive. Thermo-mechanical permeability enhancement in front of the advancing thermal sweep was observed and counteracted by the re-precipitation of minerals previously dissolved in the cool injection water. Near the injection well, calcite dissolution is capable of increasing permeability by nearly an order of magnitude, while precipitation of amorphous silica onsets more slowly and can completely offset this increase over the very long term (greater than 10 years). With the reinjection of highly-silica-saturated water, amorphous silica is capable of drastic reduction in permeability close to the injection well. Given combined action from all mechanisms, permeability varies by two orders of magnitude between injection and withdrawal.

6.1.3 Experimental and Analytical Research on Fracture Processes in Rock

As a part of the continued efforts to expand research and development on fracture processes for geothermal systems, a number of studies were conducted at MIT beginning in June, 2006. The research, attempted to address the following areas: 1) Fracture Formation and Growth and 2) Fracture Evolution, in the context of EGS technology development. As is well known, water flow through fractures is used as the major process to extract heat in EGS. Creating new fractures in geothermal reservoirs is essential in EGS development as natural fracturing is often insufficient for the creation of an operable EGS system. On account of the need to create fractures manually, a thorough understanding of the fracture process is quintessential for EGS development. The work conducted in this research consisted of experimentation on crack propagation and coalescence in granite.

Unconfined compression tests on granite with different flaw (existing crack) geometries were conducted in the laboratory. The fracturing process showed similar phenomena as earlier tests on marble and to some extent on gypsum[246]: white patches or "process zones" developed. In the study of fracture formation using an applied uniaxial stress on rock samples under certain conditions, macroscopic white patches or "process zones" form when the two sides of a crack slide against each other. Process zones are now known to consist of very tiny cracks that coalesce to form macroscopic shear or tension cracks. Two categories of white patches were observed in this study: diffuse and linear. This was different from marble where only linear patches were observed.

Tensile cracks often, but not always, developed in the white patch zones; they grew and propagated very quickly. They often initiated in zones having some white patches. Tensile cracks normally followed grain boundaries as they propagated. Tensile wing cracks did not always initiate at the tips of flaws, but rather in zones of white patching above or below flaw tips. These small tensile cracks then extended and connected with the nearest tip of the other flaw.

Shear cracks developed usually unrelated to the white patch zones and generally occurred in conjunction with surface spalling—probably indicating a compressive state of stress. Diffuse grain lightening often preceded longer shear cracks. In observable shear cracks, they generally initiated and propagated along grain boundaries, although some grain breakage was observed.

The project continued well after the period of this history. Further information on the results and more details on the major experiments have been published.[247]

6.1.4 Fracture Propagation under Poro-Thermoelastic Loads and Effects of Silica Precipitation on Fracture Permeability

Important coupled processes that control flow and heat extraction in an EGS reservoir include:

- Fracture closure/opening in response to changing effective normal stress,
- Fracture shear dilation during stimulation and circulation,
- Thermoelastic effects in stimulation and circulation operations, and
- Chemical dissolution and precipitation during circulation.

The objective of this project, conducted at the University of North Dakota (and subsequently at Texas A&M University), was to develop advanced two-dimensional, thermo-mechanical models that allow investigation of these processes in a geothermal environment. Rock mechanics models were formulated that considered significant hydraulic and thermo-mechanical processes and their interaction with the in situ stress state. The number and complexity of the processes involved in drilling, stimulation, and circulation precluded development of a single model for treatment and analysis of various problems. Thus, a number of analytic and numeric models were developed.

The research demonstrated the relative importance of thermal and poroelastic processes in EGS development. For long-term circulation operations, thermoelastic effects dominate poroelastic ones. However, the poroelastic effects contribute to injection pressure increases at early times due to induced fracture closure. In addition, changes in fracture permeability under poro-thermoelastic loads and silica reactivity were studied. The governing equations of the model were solved analytically to investigate fracture aperture changes caused by low-temperature fluid injection and fluid leak-off into the formation.

The corresponding pressure profiles were also calculated. Both solute reactivity along the fracture and diffusion into the rock-matrix were considered using temperature dependent reaction kinetics for a single component (silica). The results indicated that for longer injection times the circulating fluid attains saturation farther away from the injection point. Undersaturated fluid injectate has a tendency to increase the aperture, while supersaturated fluid leads to fracture closure. Similarly, fluid leak-off can influence silica dissolution/precipitation by a considerable amount over long injection times. Although fluid leak-off does not change the fracture aperture significantly, it can lead to an increase in pore pressure.

In a related DOE-funded project, a 3-D boundary element model for heat extraction/thermal stress was coupled with a 3-D elastic displacement discontinuity model to investigate the fracture opening and slip in response to fluid injection 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 were estimated. Not only did tensile stresses develop due to cooling, but compressive stresses were generated just outside the fracture or the fluid front, consistent with strain compatibility. This mechanism is similar to the poroelastic effect used to explain earthquakes triggered on the flanks of petroleum reservoirs due to fluid extraction. Displacement analysis indicated that under typical field conditions at Coso, a substantial increase in fracture slip was observed when thermal stresses are taken into account.

For conditions similar to the Coso geothermal field, the predicted slip was of the order of a centimeter for a few months of injection/extraction. This slip can be accompanied by seismicity; it would also result in redistribution of stresses in the rock mass that may induce slip and seismicity elsewhere in the reservoir. The temporal distribution of the thermal stresses also suggests that their contribution to rock mass deformation will not stop upon cessation of water injection and can be a factor in delayed or recurrent seismic activity.

UND also investigated the dynamics of magma-chamber fault interactions with reference to the Coso system. A 2-D, poro-viscoelastic, finite element, geomechanics model with damage mechanics was developed for predicting zones of fluid accumulation and deformation-induced fluid flow and migration. The geologic setting of the Coso field was interpreted as a releasing bend, step-over structure formed by the Airport Lake and Owens Valley dextral strike-slip fault system (Figure 46). The role of the Coso volcano-magmatic center in the development of the "over-step" structure was examined by treating the magma chamber as a liquid inclusion in a viscoelastic crust containing a fault (Airport Lake). The problem was numerically solved using a 2-D viscoelastic finite element model with thermally activated viscosity to account for thermal weakening of the rock. The temperature distribution around the magma body was calculated based on a 3-D steady-state approach and using the mesh-less numerical method. The fault was modeled as a frictionless contact. The simulated distributions of stress and strain around the inclusion display a rotation caused by the shearing component of the applied transtension. The results indicated that the fault tends to overstep the chamber in a geometric pattern similar to a step-over. There was good agreement between the computed distributions of the maximum shear stress in the vicinity of the magma chamber and the map of earthquake epicenters at a depth of 7-10 kilometers (4-6 miles).

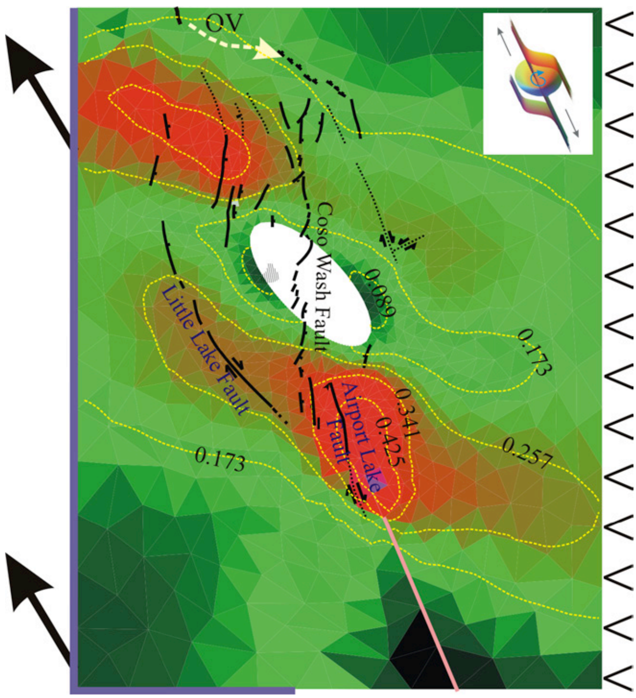


Figure 46. Shear slip (m) in the y-direction in the absence of thermal stresses

6.1.5 Magnetotelluric Imaging of EGS Reservoir Zones

Significant advances in the application of the magnetotelluric (MT) method to geothermal systems were made under the EGS program. Under DOE and U.S. Navy sponsorship, the University of Utah (UU) acquired 101 high-quality sensor soundings in the Coso geothermal field of southeastern California.[248] To achieve this quality, which heretofore was not possible, novel techniques of remote referencing were developed to suppress non-planar EM interference from power production in the Coso field and from the giga-watt scale Bonneville Power Authority (BPA) transmission line running alongthe west side of the field. These techniques included adaptation of the archived time series from the Parkfield (California) MT observatory for the first 40 percent of the survey stations, and then establishment of a dedicated remote reference 600 mi to the east near Socorro, NM, linked with Coso through the UU via fast file transfer protocol (FTP) (Figure 47). UU demonstrated the far reach of possible EM interference; merely placing the reference at a location where the noise sources have become plane-wave is insufficient.

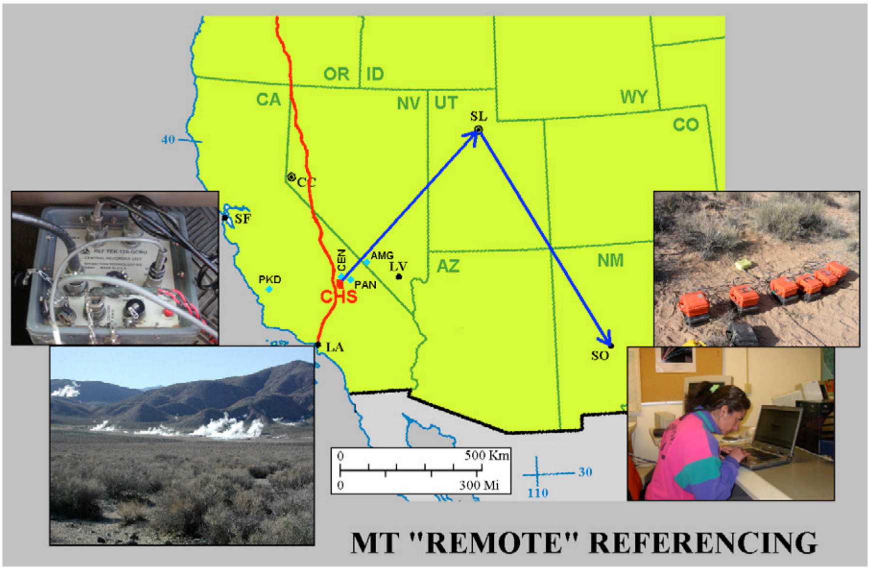


Figure 47. Schematic illustrating logistics of ultra remote referencing applied to magnetotelluric (MT) data collection at the Coso geothermal field. Reference stations even as far as Amargosa Desert (AMG) in Nevada were insufficient to cancel noise from the BPA DC transmission line (red). Noise cancellation was achieved by applying observatory data at Parkfield (PKD) and using a reference at Socorro, New Mexico.

Improvements in 3-D MT resistivity inversion capability and interpretation of the Coso data set were carried out. UU was able to substantially modify an existing Gauss-Newton, finite–difference, 3-D inversion algorithm from Kyushu University for better efficiency and convergence on desktop computers. The inversion of the Coso data (Figure 48) showed a steeply dipping conductor under the western portion of the East Flank area that tentatively correlated with the reservoir zone. The conductor's position was corroborated by 2-D MT mode inversion of a coincident dense MT array profile. When deepened, well 34-9RD2 encountered pronounced lost circulation at depths corresponding to the eastern edge of this conductor. The information content of UU's 3-D model was essentially equivalent to that produced from a massively parallel inversion calculation using a huge amount of computing power.[249]

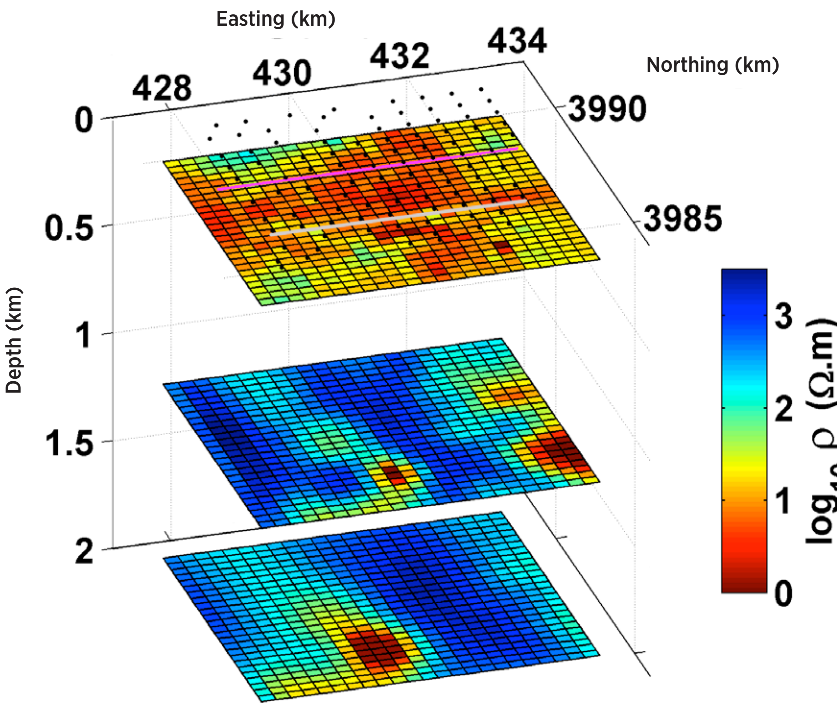


Figure 48. Plan view slices at depths of 150, 1,200 and 2,000 meters, showing the model parameters recovered from 3-D MT inversion[250].

The MT station locations are shown without topography. The gray line indicates the approximate location of the 9-station 2-D profile shown by[250]. The magenta line shows approximate location of a dense array MT line. The color bar is clipped at 1Ω.m and 3200 Ω.m.

6.1.6 Evaluating Permeability Enhancement Using Electrical Techniques

EGS techniques seek to increase flow capacity by hydrofracturing hot, impermeable rock by pumping high-pressure fluid into one or more injection wells and enhancing permeability by opening pre-existing sealed fractures and/or creating new ones. Although there is little question that fracturing rock and creating permeability in this way will often be feasible, the real difficulty is appraising, in detail, the permeability structure of the induced fracture network. The hydraulic connections between the production and injection wells should be neither too poor (resulting in no fluid flow) nor too good (resulting in "short-circuiting" and rapid cooling). Unless the permeable fractures can be accurately mapped, the cost of subsequent trial-and-error drilling to establish a suitable fluid circulation system is likely to dominate project economics and render EGS noncompetitive in the energy market for the indefinite future.

The current state of the art in hydrofracture evaluation and characterization is MEQ monitoring, but this technique, by itself, does not provide sufficient precision concerning fracture locations and cannot distinguish permeable fractures (connected to the fracture network) from impermeable (isolated) ones. But combining microearthquake monitoring with downhole self-potential electrical monitoring has the potential to provide more information than either technique alone.

This project arose out of a preliminary feasibility study carried out in 2003-2004 and later reported at the 2005 World Geothermal Congress in Turkey.[251] Subsequently, under DOE sponsorship, a multi-year effort was undertaken by SAIC to: 1) elaborate and generalize the theoretical feasibility study results,[252] 2) carry out laboratory testing of relevant rock samples from candidate EGS sites to obtain pertinent electrical properties, 3) design the in situ sensors required for subsurface electrical monitoring,[253] and 4) devise computer simulation software useful for interpretation of the transient electrical signals caused by fracture pressurization.[254] The resulting software and documentation were completed after 2006.[254]

6.1.7 Real-Time Fracture Monitoring In Engineered Geothermal Systems with Seismic Waves

Shear-wave splitting (SWS) occurs when a seismic wave travels through stress-aligned, fluid-filled fractures or other inclusions in the upper part of the earth's crust. SWS is emerging as a useful exploration tool for geothermal reservoirs as it can detect the geometry of the fracture system, the intensity of cracking and possibly changes in fluid pressure within the reservoir. The method is based on the observation that a shear-wave propagating through rocks with stress-aligned microcracks (also known as extensive dilatancy anisotropy or EDA-cracks) will split into two waves: a fast one polarized parallel to the predominant crack direction, and a slow one polarized perpendicular to it. Thus by measuring the fast shear-wave polarization (φ) and time delay (δt) from local microearthquakes, one can detect the orientation and intensity of fracturing in fracture-controlled geothermal fields.[255-257]

Based on research at several geothermal fields in California and Iceland sponsored by DOE, the University of North Carolina (UNC) formulated a number of algorithms that can, in principle, make real-time monitoring of subsurface fracture systems possible in geothermal fields. Seismic data are collected from an array of three-component seismic sensors, which record both natural and induced local seismic events. When a seismic event is detected it will be readily located, provided the record is available at no less than four seismometers. If shear-wave splitting is detected for an event, both SWS parameters (φ and δt) will be automatically measured using a newly developed method based on the analysis of multiple time windows. In this method an automated SWS algorithm is applied to a series of time windows to yield a series of estimated pairs of φ and δt. A cluster analysis applied on these estimated pairs determines the best estimate of polarization and time delay. Then, if the event is within the shear-wave window of any recording seismic station, the measured parameters will be combined with previously measured shear-wave splitting parameters within the shear-wave window of the same station and inverted for the orientation (in terms of strike and dip) and intensity of cracks in the vicinity of that station.

6.1.8 Microearthquake Data Analysis Tools for Enhanced Geothermal Systems

Foulger Consulting, in conjunction with the USGS conducted two analytical studies of MEQs as a means of characterizing EGS reservoirs. Those studies were: Seismic (MEQ) Characterization of EGS Fracture Network Lifecycles and Micro-earthquake Technology for EGS Fracture Characterization.

Both projects were aimed at 1) developing improved seismic data processing techniques to extract the most accurate possible parameters of use in EGS operations, 2) applying those techniques to case histories in an effort to develop an operational geophysical tool, and 3) transferring the results to the public sector.

EGS development projects aim to hydrofracture hot, low-permeability rock formations in order to create fracture networks through which fluid can be circulated in order to extract heat. Mapping the exact location and orientation of the fractures is critical to the success of such projects. Essentially the only way of measuring the fractures is to locate the MEQs generated by hydrofracturing operations very accurately. A significant part of the work focused on developing better techniques for calculating absolute and relative MEQ locations using 3-D crustal models, enhanced relative relocation techniques, and waveform cross correlation.

Knowing the mode of faulting during fracture creation is also potentially useful, in particular crack opening and closing components. These can be calculated from general moment tensors, which give the earthquake focal mechanisms including volumetric components. Thus, crack-opening-type earthquakes can be distinguished from shearing types. Under the two DOE grants, existing methods for calculating moment tensors were tailored for the type of data typically collected in EGS projects.

6.1.9 Chemical Stimulation of Engineered Geothermal Systems

The objective of this project, performed by EGI at the University of Utah, was to design, develop and demonstrate methods for enhancing the permeability of candidate EGS reservoirs through the use of mineral dissolution agents.

In many candidate EGS reservoirs, there is a pre-existing fracture network, but the fractures are impermeable. Minerals have deposited on the fracture walls, blocking the natural flow of fluids through the fractures. The implementation of a successful chemical approach for stimulating candidate EGS reservoirs could provide a significant cost savings over conventional hydraulic stimulation by enhancing permeabilities—especially in near-wellbore formations. EGI conducted the project in a series of steps:

- Identify a set of candidate chemical compounds capable of dissolving minerals commonly found in near-wellbore EGS formations.
- Screen each candidate for thermal stability and reactivity.
- Conduct a detailed analysis on each compound that emerges from the screening tests in order to characterize its decay kinetics and reaction kinetics as functions of temperature and chemical composition.
- Develop numerical simulation models of laboratory flow reactor data and extend those models to predict full-scale EGS experiments.
- From among the compounds emerging from the laboratory studies, conduct a field study in order to demonstrate the process under real-world conditions.

Two chelating agents, ethylenediaminetetraacetic acid (EDTA) and NTA emerged from the screening studies and were subjected to detailed kinetics analyses. These compounds were shown to be effective in dissolving calcite and other calcium-bearing minerals at the high temperatures present in geotheremal formations. Furthermore the dissolution kinetics of the chelating agents was shown to be more appropriate than those of strong mineral acids, allowing for more complete coverage of the near-wellbore formation. Caustic solutions were shown to be effective for dissolving silica and silicate minerals. In addition, solutions of chelating agents at high pH and high temperature were capable of simultaneously dissolving calcite, silica, and silicates. Numerical models were generated to successfully simulate the bench scale dissolution reactor experiments. A field experiment at the Coso geothermal field using the chelating agent NTA at high pH resulted in the full restoration of flow of a previously occluded production well.[258]

6.1.10 Isotopic Evaluation of Fluid/Heat Transfer Efficiency

The objective of this LBNL project was to determine the effects of fluid injection on in situ and produced gas compositions and isotopic ratios of an EGS reservoir.

The study examined heat and mass transfer between fractures and the rock matrix along with mineral-water-gas reactions. The TOUGHREACT code, which had been used previously to model the reactive-transport behavior of CO_2, ^{14}C, and $^{18}O/^{16}O$ in boiling unsaturated systems, was used for geothermal reservoir analysis. The methodology would be relevant for evaluating and predicting: 1) the effects of injection on existing geothermal fields, and 2) the efficiency of heat transfer in EGS reservoirs. Because the methodology employed an available reactive-transport code (TOUGHREACT), field-scale problems could be readily tested.

A reactive-transport model for ^{14}C was developed to test its applicability in a geothermal system. The system selected was that supplying the Aidlin power plant at The Geysers, located in an isolated section in the northwest portion of the field. Using TOUGHREACT, LBNL developed a 1-D grid model to evaluate the effects of water injection and subsequent water-rock-gas interaction on the compositions of the produced fluids. A dual-permeability model of the fracture-matrix system was used to describe reaction-transport processes. The geochemical system included the principal minerals (K-feldspar, plagioclase, calcite, silica polymorphs) of the metagraywackes that comprise the geothermal reservoir rocks.

Initial simulation results predicted that gas-phase CO_2 in the reservoir would become more enriched in ^{14}C as air-equilibrated injectate water (with a modern carbon signature) was added to the system. These changes would precede accompanying decreases in reservoir temperature. The effects of injection on ^{14}C in the rock matrix would be lessened somewhat because of the dissolution of matrix calcite containing ^{14}C-depleted carbon.

Viability of the model was tested through a monitoring program initiated at an isolated section in the northwest portion of The Geysers, California at the Aidlin plant and beginning in 1996. Noncondensable gases and condensate were periodically sampled from the production and injection wells. The Aidlin portion of the field is characterized by high reservoir temperatures (260°C to 290°C [500°F to 554°F]) and elevated noncondensable gas contents. Since production began at Aidlin in 1989, injection consisted primarily of relatively limited volumes of steam condensate at rates of 750 l/min, with variable seasonal contributions of surface and well waters.

Beginning in November 2005, more extensive injection using reclaimed water from the Santa Rosa–Geysers Recharge Project[259] was initiated at the Aidlin area, with the goal of increasing steam production and reducing problems associated with the high gas contents of the produced fluids. This provided an excellent EGS analog for studying the potential impact of increased injection on fluid-rock interactions and how chemical and isotopic compositions may define the interactions. The reclaimed water contained natural tracers, such as ^{14}C, that was monitored to study the movement of injectate throughout the Aidlin field.

The combined results of the field chemical monitoring and the reactive transport modeling suggested that ^{14}C could serve as an effective tracer for the injection of reclaimed water within the Aidlin geothermal reservoir and presumably throughout The Geysers. With injection, the movement of ^{14}C occurs more rapidly through the simulated reservoir than the temperature decline that accompanies injection. The analytical results from field sampling conducted prior to and after injection of reclaimed water at Aidlin were used to constrain and refine the reaction models.[260-261]

6.1.11 Geochemical and Isotopic Studies Related to Enhanced Geothermal Systems

The efficiency of heat extraction from geothermal reservoir rocks is limited by chemical processes and the physical characteristics of the reservoir. Specifically, mineral dissolution and precipitation and the geometry of heat and mass exchange between fluids and the reservoir rocks define the long term efficiency of heat extraction. But the geochemical reactions are difficult to quantify and therefore predict. A project by LBNL studied water-rock isotopic exchange in geothermal systems to facilitate decisions about the management of natural and enhanced geothermal systems.

The chemical composition of a geothermal fluid comprises the net product of mineral dissolution and precipitation. Isotopic systems, such as oxygen and strontium (a trace element in natural waters), can provide additional information about the processes occurring as a result of water-rock exchange. Evidence has been found that calcium, a major cation in most natural waters, can be fractionated during the precipitation of calcite.[262] In this case, the precipitated calcite is depleted in the heavier isotopes of calcium while the residual Ca in the fluid is enriched in those isotopes. Therefore, calcium isotope data may preserve a record of mineral precipitation.

The project focused on combined isotopic systems to evaluate their ability to quantify and constrain both dissolution and precipitation of major and secondary mineral phases along the flow paths of geothermal fluids.

Two field studies were conducted. In the first, baseline chemical and isotopic data were collected from production wells at the Coso Geothermal Field, California, in preparation for the planned EGS stimulations at Coso. Sampling focused on the East Flank area of the field where stimulation was initially planned for well 34-9RD2. Fluids were sampled from nine wells and two fumaroles. There was a surprising amount of variability in fluid chemistry over this relatively small production area, and while some of this variation can be explained as exploitation effects, seemingly clear evidence of compartmentalization of production zones was found.

Nearly all of the wells studied showed evidence of having tapped high-temperature inflows at some time in the past, based on the different geo-indicators applied in this study. Given that the various equilibria that were applied are kinetically controlled, these apparent inconsistencies almost certainly relate to how the system evolved in the recent geologic past and how it was now responding to current exploitation (e.g., conversion to a two-phase vapor-liquid or, in time, even a vapor-static regime).

The highest indicated temperatures from $^{13}CO_2$-$^{13}CH_4$ fractionation point to values as high as 400°C [752°F] that reach and even exceed those of the plastic-brittle transition for silicic rocks. Gases carrying these highest signatures derive from feed zones supplying wells 51A-19, 38A-9, and 64-16-RD2. The high-temperature feedstocks carrying such signatures into these wells should be considered as the most direct conduits to the heat source.

$^3He/^4He$ isotope ratios showed evidence of matrix-fracture transfer of radiogenic ^4He, which is most likely a result of exploitation-induced reservoir boiling. While this mechanism has been proposed to explain similar changes in other producing geothermal systems, this also has interesting ramifications for natural systems which undergo depressurization due to dry out.

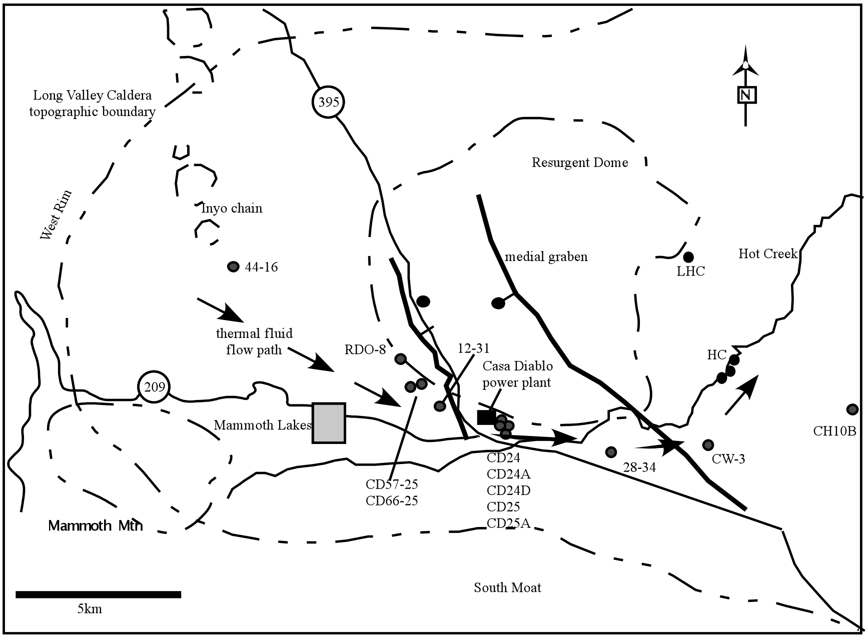


Figure 49. Map of Long Valley Caldera showing the proposed flow path of the Long Valley hydrothermal fluid (arrows) that emerges in the west moat near well 44-16 and locations of geothermal well samples (black filled circles)

The second field project focused on samples collected from ground water monitoring and geothermal production wells along the presumed flow path across the geothermal system in Long Valley Caldera, California (Figure 49).[263] The site was selected as an analog for EGS systems to study the impact on fluid isotopic structures induced by water-matrix interaction along a fluid flow path. Available literature data provided constraints on flow paths, flow rates, and matrix lithologies and secondary mineral compositions. Samples were analyzed for the isotopes of water, Sr, Ca, noble gases, the concentrations of major cations and anions and total CO_2.

The data confirmed earlier models in which the variations in water isotopes along the flow path reflect mixing of a single hydrothermal fluid with local groundwater. Correlated variations among total CO_2, noble gases and the concentration and isotopic composition of Ca suggested progressive fluid degassing driving calcite precipitation as the fluid flows from west to east across the caldera. This was the first evidence that Ca isotopes may provide definitive evidence of calcite precipitation along fluid flow paths in geothermal systems.

6.2 Industry Field Demonstration Projects

Field demonstrations resulting from DOE's solicitations of 2000 and 2002 were largely focused on sites within or on the periphery of existing commercial hydrothermal fields. This focus reflected a strategy of first applying EGS technology within operating fields, then moving to the periphery of operating fields, and finally developing a greenfield (an area without prior geothermal development). The intent was to win industry support for EGS by first demonstrating the technology at well-characterized fields.

From the solicitation in 2000, nine field demonstration projects were selected for further study. The projects were winnowed down to three through a systematic process of elimination. Those projects were located at: 1) Coso, California; 2) Desert Peak East, Nevada; and 3) Glass Mountain, California. Coso represented a project within an operating field; Desert Peak East was on the periphery of an operating field; and Glass Mountain potentially represented a greenfield project. The project at Glass Mountain was stymied by continued protests over geothermal development at Medicine Lake. DOE's industry partner, Calpine, requested that the project be moved to The Geysers—specifically the Aidlin plant, which had been experiencing production problems due to acidified steam. The project was officially moved, but DOE and Calpine could not agree on how to proceed, and the partners eventually decided to terminate the project. The other two projects are described briefly in the following sections.

6.2.1 Coso Hot Springs, California

Coso Hot Springs is a commercial geothermal field in southern California with an installed capacity of 270 MW. The objective of the EGS project was to stimulate one or more low permeability injection well(s) through a combination of hydraulic, thermal and chemical methods and to connect the injector(s) hydraulically to at least one production well in the field. Thus, the goal was not only to design and demonstrate the feasibility of creating an EGS in an existing geothermal reservoir, but also to understand that process in order that it might be applied wherever appropriate geological conditions exist. The project was a collaborative effort with EGI (UU), USGS, and Coso Operating Company. EGI was the lead organization.

The approach taken by the project was to collect as much scientific and technical information as deemed necessary to understand the reservoir system and subsequent stimulation experiments. In this respect, the project was intended to be a model for future EGS experiments. The geothermal resource was characterized by applying a set of analytical geological tools. These tools included borehole image-log analysis for imaging fractures and determining regional stresses, petrographic and petrologic analyses of borehole cuttings, petrophysical measurements of core samples, and geophysical methods, particularly microseismicity and MT studies.

Models of geomechanical processes, fluid-mineral interactions, and fluid flow processes were to be developed and subsequently calibrated using data obtained from hydraulic stimulation field experiments. Updated and calibrated models could then be used to predict the success of future EGS projects in any geological setting. A detailed analysis was required in order to develop a geomechanical model of the reservoir, to determine which fractures were optimally oriented and critically stressed for shear failure, and to determine their role in reservoir permeability. The geomechanical model included pore pressure, uniaxial compressive rock strength, and the magnitudes and orientations of the principal stresses including the maximum horizontal stress, the minimum horizontal stress, and the vertical stress. These were 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.

Petrographic and petrologic studies were implemented in order to construct the overall geologic framework of the east flank of the Coso field, document and characterize geothermal and older fluid flow paths, and aid in the interpretation of formation microscanner (FMS) and borehole televiewer (BHTV) logs.

The purpose of the microseismicity task was to improve 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 EGS. To do this, modern seismological methods were applied in order to determine complete earthquake mechanisms, high-resolution hypocenter locations, and four-dimensional (time-varying three-dimensional) structure. The information 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, and pore-fluid state.

A hydraulic stimulation experiment was conducted under very low well head pressures on injection well 34A-9 in an attempt to increase near-reservoir permeability. During these experiments, steam condensate was injected in large volumes at pressures well below the least principal stress. The experiment was very successful as the otherwise failed well was turned into a highly permeable injector. A subsequent circulation test showed that the newly stimulated well had a connection with nearby production wells.

During the workover of the target injection well 34-9RD2, the lower portion of the well was redrilled. During this redrill, a modestly permeable fractured zone was penetrated whose permeability was greatly enhanced by drilling fluids pouring into the fractured zone. Seismic activity resulting from this process was monitored. An analysis of the microseismic data indicated that hydraulic fracture(s) had been created and monitored during the redrilling process. This represented the demonstration of a real, if accidental, stimulation of an EGS formation at the Coso geothermal field.[264-265] The results of this research have been published.[266]

Since the target well was no longer suitable, the project team selected a new well, 46A-19RD, in the southwest quadrant of the field. The well had been drilled in 1994 to a depth of 3,864 meters (12,678 feet) and a bottom-hole temperature in excess of 350°C (660°F). However, attempts to retrieve the well's liner during workover operations were unsuccessful, and by mutual agreement, the project was terminated.

6.2.2 Desert Peak, Nevada

As a result of the solicitation in 2004, Ormat Technologies Incorporated conducted an industry-DOE cost-shared field project to evaluate the technical feasibility of developing an EGS power generation project at the Desert Peak geothermal field in Churchill County, Nevada. The Desert Peak field produces 15 MW of power from a conventional geothermal (i.e. hydrothermal) reservoir.[267] GeothermEx, an independent consulting firm, served as the technical manager of the project. The focus of Phase I of the project was an existing "well of opportunity" (DP23-1), drilled just east of the Desert Peak field. The well is located in a part of the thermal anomaly that is non-productive, within a potential EGS area covering about two square miles. A number of preliminary studies were conducted (e.g., petrographic analyses, image logs, seismic network installation) during Phase I.

Plans were made to re-complete well DP23-1, casing off zones that were either mechanically unstable or otherwise unfavorable for hydraulic stimulation. The workover plan included collecting cores from bottom-hole for geological evaluation and mechanical testing, and conducting a "mini-frac" to determine the magnitude of the least principal stress, a critical parameter for designing the hydraulic stimulation that would be conducted in Phase II of the project. However, due to major problems during workover, this plan could not be carried out, and the well had to be abandoned. Subsequently, the project was shifted to another non-commercial well (DP 27-15) located within the hydrothermal portion of the field.

In Phase II of the project, Ormat planned to undertake chemical and/or hydraulic stimulation of DP27-15, post-stimulation production, injection, tracer and long-term interference testing to evaluate the new hydraulic configuration of the reservoir, and to update the numerical model and its forecasts of the long-term behavior of the Desert Peak field. The project was ongoing as of the end of 2006.[268-270]

6.3 Induced Seismicity

One controversial issue concerning EGS projects is the potential impact of induced seismicity normally associated with EGS operations. This phenomenon has been the cause of delays and threatened cancellations of at least two EGS projects worldwide. Although MEQs from EGS operations have had few, if any, adverse physical effects on the site or on those living near the site, there remains a strong public concern over the amount and magnitude of the seismicity that may be associated with EGS operations.

To a certain degree, induced seismicity has been an issue at many geothermal fields, especially those involving the injection of fluids. In the late 1970s DOE sponsored studies of induced seismicity associated with injection at The Geysers (see Section 1.1.2). Those studies proved conclusively that the observed seismicity was linked directly to injection, but the magnitudes of the earthquakes were such that the issue was not considered serious. That conclusion changed with the addition of treated wastewater to the injection stream in the late 1990s. The increased volumes and rates of injected fluids brought about a concomitant increase in the magnitude and frequency of induced seismic events.

By the very nature of EGS reservoir creation and production, induced seismicity is virtually unavoidable. In fact, microearthquakes associated with EGS fracture stimulation are essential to the identification and mapping of fractures within the rock mass targeted as a potential reservoir. Induced seismicity allows operators to monitor the effectiveness of EGS operations and sheds light on geothermal reservoir processes.[271] Consequently, DOE sought to address induced seismicity in an EGS context.

The primary objectives of the EGS induced seismicity study, led by LBNL, were to present an up-to-date review of what was already known about the seismicity induced during the creation and operation of an EGS, and identify knowledge gaps that, once addressed, should lead to an improved understanding of the mechanisms generating the events. Case histories were investigated to illustrate a number of technical and public acceptance issues. The study concluded that EGS-induced seismicity need not pose a threat to the development of geothermal energy resources if site selection is carried out properly, community concerns are properly handled, and operators understand the underlying mechanisms causing the events.[16]

As an initial starting point for the project, three international workshops were organized with participants from a variety of backgrounds, including experts in seismic hazards analysis and other relevant specialties. The workshops were held during the Annual Meeting of the Geothermal Resources Council, Reno, Nevada, in October 2005, and the annual Workshops on Geothermal Reservoir Engineering, Stanford University, Palo Alto, California, in February 2005 and February 2006.[271-272]

The project culminated with a peer reviewed white paper and a recommended protocol for dealing with induced seismicity.[16] The white paper and protocol were subsequently accepted by the Executive Committee of the Geothermal Implementing Agreement under the International Energy Agency. An additional paper on seismicity at The Geysers was also published.[273] However, subsequent induced seismic events at Basel, Switzerland, where an event of local magnitude of approximately 3.4 occurred in late 2006, and Soultz sous Forêts, France, where events up to local magnitude 2.9 occurred in 2003, increased the public's concern about this issue.

Despite the publicity over the earthquakes at Basel and Soultz, there has been no known instance of a seismic event associated with an EGS project causing any major damage or injury. But that is not reason for complacency in managing the EGS-induced seismicity issue. The occurrence of felt events may be a characteristic of EGS operations. How EGS reservoirs behave seismically over the long term remains to be seen. This is uncharted territory since no EGS project has gone into long-term production. Public education and acceptance and the application of accepted best practices are required to prevent induced seismicity from delaying or preventing EGS development.

6.4 Is EGS the Future of Geothermal Energy?

By 2004, the priorities of energy R&D within DOE had changed. Considerable emphasis was placed on a hydrogen economy and the technologies needed to bring that economy to market. Geothermal energy was hampered by lack of growth in the U.S. geothermal industry. Indeed, there had been little new construction of domestic geothermal plants for well over a decade, and some analysts felt that new growth was unlikely. Resource development appeared to be capped and limited to the expansion of existing fields. This stagnancy contrasted with other renewable resources which were reinvigorated after the slow growth period of the 1990s.

Incentives, such as a Production Tax Credit (PTC) and state-imposed Renewable Portfolio Standards (RPS) helped fuel a resurgence in the renewable energies; geothermal energy benefited as well. However, the PTC only had marginal impact on geothermal development due to the law's sunset or termination provisions that limited the period over which a facility would be eligible to apply for the credit.

Geothermal facilities, which normally take three to five years to build, would not be able to meet the eligibility requirements in the time allotted. And the high risk of geothermal resource exploration and discovery continued to hamper access by developers to investment capital.

The Geothermal Program responded to the challenge posed by the perceptions of geothermal energy within the Government by instituting several projects to evaluate the resource's potential. DOE negotiated a memorandum of understanding with the USGS to conduct a new national resource assessment. The last assessment had been done in the late 1970s and had remained the definitive reference for geothermal resources despite being outdated. In addition, a program-wide roadmapping effort was begun to help redirect the Program. However, the project that would prove to have the most lasting impact was a feasibility study sponsored by DOE and managed by INL and performed by MIT.

With the realization at the time that EGS technology was the best means for geothermal energy to make a significant addition to the nation's energy supply, DOE asked MIT to conduct a feasibility study of EGS. The study, which began in the summer of 2005, considered three aspects of feasibility:

1. **Resource feasibility**: Was the geothermal resource base large enough and widespread enough to merit development with EGS technology?
2. **Technical feasibility**: What were the technical barriers to EGS development and how could they be overcome? Were there any "show stoppers"?
3. **Economic feasibility**: Could the costs of EGS development become competitive in future energy markets?

MIT organized a panel of experts to consider these questions. The panel met during the remainder of 2005 and early 2006, culminating in a draft report. DOE conducted an independent peer review of the draft which was finalized over the summer of 2006. DOE senior management was briefed on the report in July 2006, and the report's findings were released to the geothermal community at the 2006 annual meeting of the Geothermal Resources Council. The final report—"The Future of Geothermal Energy–Impact of Enhanced Geothermal Systems on the United States in the 21st Century"—was published by MIT in late 2006.[247]

In essence, the study found that the geothermal resource was indeed as large as indicated in earlier estimates by the USGS and others. There were technical barriers that prevented that resource from being exploited with EGS technology, but those barriers could be overcome with a relatively modest infusion of research capital by government and industry. Finally, EGS technology could become economically competitive within a short period of time due to technology improvements, learning experience, and market incentives.

The report concluded that EGS could account for 100,000 MWe of new power production at economical costs within 50 years. The report had an immediate and lasting impact on the perception of decision makers and the public at large about the efficacy and benefits of geothermal energy. This led to a revival of interest and renewed emphasis on geothermal technology development within DOE. That revived interest promises to carry the Geothermal Program forward into a new era of advanced research and development that will enable geothermal resources to fulfill their potential as a major energy source.

Conclusion

At the beginning of DOE's geothermal R&D program, the U.S. geothermal industry was small and struggling to gain acceptance from utilities and financial institutions, which had only a rudimentary understanding of the costs and risks associated with geothermal energy projects. There was little solid data in the public domain on which reliable analyses of geothermal reservoirs as viable energy resources could be based. Reluctance to support geothermal projects financially was causing stagnation in the nascent geothermal industry. In addition, there was only limited understanding of the nature of geothermal systems and of how they could be gainfully used.

The DOE-funded research on reservoir engineering described in this report—along with the work described in companion reports on Drilling, Energy Conversion, and Exploration—had an immediate and profoundly positive effect by stimulating development of the modern geothermal industry. This achievement was realized through performance of collaborative projects in which DOE-funded scientists and engineers from the national laboratories, academic institutions, and the private sector worked with colleagues in companies, other government agencies, and institutions in other countries to address the full range of problems inhibiting economic geothermal development. Research priorities were continually assessed and updated in close collaboration with industry to ensure that project results would be of practical use. The success of DOE's program can be seen in today's vital and progressive geothermal industry.

Over three decades, from 1976 to 2006, the Department's support of reservoir engineering R&D focused on such major research areas as field case studies of The Geysers and other geothermal reservoirs; the Geothermal Reservoir Well Stimulation Program; the Hot Dry Rock Program at Fenton Hill, New Mexico; the Geopressured-Geothermal Energy Program in the Gulf Coast states of Texas and Louisiana; reservoir modeling and simulation, tracer development and interpretation, and the Enhanced Geothermal Systems Program. In addition to contributing to a decrease in the cost of geothermally-generated electricity, much of this work also resulted in the commercialization of Government-supported technologies by the U.S. geothermal industry and others.

The Department continues to support research and development activities and industry partnerships to encourage and help the U.S. geothermal community to meet these challenges, building on the technical research base of the past 30 years. This technical base provides the information and understanding necessary to create more efficient, reliable, and economic technologies, enabling the U.S. geothermal industry to compete for baseload electricity generation. It is hoped that this summary of prior work in reservoir engineering R&D will allow future geothermal developers and researchers to translate past efforts into future accomplishments.

Appendix A:
Budget history of the federal geothermal research program, 1976 – 2006

Notes on Budget Table

The following discussion is provided to clarify the meaning and intent behind the estimates given in the Geothermal Program budget table (Fiscal Years 1976 – 2006). Despite the precision of the table, the reader is cautioned not to accept the amounts quoted in any single fiscal year as a fully accurate representation of the funds spent on a given technical area. The reasons for this caution will become apparent from the notes. However, over the entire period covered by this history, the totals are considered reasonably accurate.

1. The funding history covers FY 1976 through FY 2006 inclusive. FY 1976 includes funding for the "transition quarter" in which the Federal fiscal year was advanced three months from June 30 to September 30. All funds are in current year dollars in thousands; no adjustments were made to cover the time value of money.

2. The Program budgets were divided among the four major technical research topics comprising the focus of the history: Exploration, Drilling, Reservoir Engineering, and Energy Conversion. For convenience, subsets of Reservoir Engineering---Geopressured-Geothermal, Hot Dry Rock and Enhanced Geothermal Systems—are listed separately to identify funds spent on those topics versus Hydrothermal Reservoir Engineering. The technical areas covered by these research topics are summarized in the Table of Contents of each history.

3. Additional line items are included for completeness. They lie outside the four research areas as defined, but they appear in the Program budget for extended periods. Those line items are mentioned briefly here:

    - **Capital Equipment** – Tools and equipment needed to carry out research, typically at the national laboratories, are identified as capital equipment. Over time, this line was either reported independently within each program area (e.g., equipment for Geopressured Resources) or included as an aggregate total for the entire program. The aggregate total is used in this budget table. In some instances this may lead to discrepancies in budget amounts between what is listed here and amounts given by other sources. The differences are minor, since capital equipment was typically a small percentage of the total budget for any line item.

    - **Program Direction** – This line covers the personnel expenses of DOE staff used to plan, implement, and manage the Geothermal Program. After FY 1995, Program Direction was aggregated at the level of the Office of Energy Efficiency and Renewable Energy, eliminating this line from the Program budget.

- **Baca Demonstration Plant** – This major project was planned as the first commercial-scale (50 MWe) liquid-dominated hydrothermal power plant in the U.S. The project was located at the Valles Caldera, New Mexico, as a government-industry partnership. The industry partners were Unocal Geothermal and Public Service of New Mexico. The project was canceled in 1983 after attempts to find adequate hydrothermal resources to support the 50 MWe plant were unsuccessful.

- **Environmental Control** – During the formative years of the Program, research was sponsored on a number of environmental topics that could have a detrimental impact on geothermal development. Topics studied to varying degrees included: hydrogen sulfide emissions, other non-condensible gas emissions, liquid effluents, land use, noise, induced seismicity, and subsidence. Environmental monitoring networks were established, notably at The Geysers, Imperial Valley, and the Gulf Coast, to collect data on subsidence and seismicity. Research was performed on environmental mitigation technology, especially hydrogen sulfide abatement.

- **Geothermal Heat Pumps** – While use of heat pumps had been a minor secondary topic for much of the Program's history, the topic became a major program element for a five-year period (FY 1995 – FY1999) when a large education and outreach effort was conducted to acquaint the public with the environmental and efficiency benefits of this technology. Research on heat pump technology was limited but did include advancements in impervious grouts and improved performance models.

- **GeoPowering the West** – This was an education, outreach, and technical support effort, launched in 2000 and patterned after the successful Wind Powering America initiative.

- **Other** – A potpourri of activities not covered elsewhere are included here, such as policy, planning, and analysis done by the Program and short-lived projects such as non-electric (direct use) demonstrations. These activities are not covered in this history.

4. The source of the budget amounts reported here is the annual DOE budget request to Congress, often referred to as the President's Request or the Congressional Budget Request (CBR). In most cases, the amounts shown are "Actual" funds budgeted for a given line item as stated in the CBR. The "Actual" funds are not necessarily the amounts appropriated by Congress for that fiscal year---differences can arise due to reductions, rescissions, or other adjustments to the budget subsequent to initial appropriations.

5. The CBR is submitted early in the calendar year, shortly after the President's State of the Union message, in order to give Congress the time needed to prepare appropriations bills before the start of the new fiscal year on October 1. Due to this scheduling of the CBR, "Actual" expenditures are reported with a two-year lag. For example, if we wished to know the actual amounts budgeted in FY 1989, they would be found in the FY 1991 CBR. FY 1989 would have ended on September 30, 1989, four months before the submission of the FY 1991 CBR to Congress. Sufficient time would have elapsed to allow a final accounting of FY 1989 expenditures, in most cases to the nearest dollar. This explains why the funds are typically reported to 4-5 significant figures, rounded to thousands. Note

that in this example the FY 1990 CBR would not be a source of complete information about FY 1989 expenditures because the FY 1990 CBR would have been submitted in early 1989, before the end of FY 1989. Therefore, the "Actual" funds reported in the CBR are considered the best source of expenditures for the fiscal year in question.

6. A major problem in using "Actual" CBR amounts stems from the fact that neither the Program nor the CBR were constant over the course of time. The Program's organization changed on a number of occasions during its 30-year history, and the format and content of the CBR changed as well. Probably the greatest impact on recreating the budgets for the topical research areas was the fact that in many cases the amounts spent on exploration, drilling, reservoir engineering, and energy conversion were aggregated under some generic title. For example, during the 1980s the major categories of Geothermal Program funding were: Hydrothermal Industrialization, Geopressured Resources, and Geothermal Technology Development. Hydrothermal Industrialization included sub-topics such as field demonstrations, test facilities, state resource assessments, and industry-coupled drilling. Technology Development covered many diverse research sub-topics such as hot dry rock, advanced drilling, geochemical engineering and materials, energy conversion, and geoscience. In some cases, the expenditures for these topical areas (e.g., hot dry rock) were reported, and the budgeted amounts could be properly allocated. However, the CBR did not always report "Actual" expenditures to that level of detail, and the amounts had to be inferred from the "Request" amount given in the CBR for the fiscal year in question. These amounts could become problematic when CBR formats changed or major programmatic reorganizations were instituted between the year of the "Request" and the "Actual" reporting year.

7. Another complicating factor was the merging of technical areas under a generic topical area. For example, the line item, "Geoscience Technology," subsumed the research topics of exploration and reservoir engineering. The amount of budget devoted to each element was usually not specified in the CBR. The problem is particularly vexing for budgets dating from FY 1999 when budget line items such as "University Research", "Core Research", "Technology Deployment", and "Systems Development" came into use. Fortunately, Program budget records apart from the CBR for this period are fairly complete, allowing assignment of funding to the appropriate research areas.

8. Despite the aforementioned caveats, many of the budget estimates are judged to be accurate. Geopressured-Geothermal was a unique line item in the budget that could be easily tracked from year to year in the CBR. Funding for Hot Dry Rock was reported separately for the life of that program. The same can be said for Capital Equipment, Program Direction, Baca Plant, and Geothermal Heat Pumps. Of the four research topical areas, Drilling Technology had the best record of budget representation over time, followed by Energy Conversion. Due to their technological similarities, Exploration and Reservoir Engineering could be difficult to distinguish. As stated above, the funding for the topical areas in any given year may reflect some uncertainty, but the aggregate totals over 30 years do provide a good estimate of relative funding levels.

Geothermal Program Annual Budget *($000)*

	Exploration	Drilling	Reservoir Engineering	Hot Dry Rock	EGS	Geopressured-Geothermal	Energy Conversion
1976	$6,280	$4,206		$5,274		$1,182	$21,209
1977	$9,000	$3,500		$5,280		$6,620	$22,350
1978	$17,600	$2,870		$5,400		$17,100	$40,630
1979	$31,270	$9,000	$8,500	$15,000		$26,600	$33,169
1980	$15,506	$8,800	$5,100	$14,000		$35,700	$30,294
1981	$25,224	$12,545	$6,547	$13,500		$35,600	$24,920
1982	$3,450	$3,036	$2,650	$9,700		$16,686	$28,858
1983	$2,360	$1,710	$400	$7,500		$8,400	$29,641
1984	$2,713	$2,640	$10,172	$7,540		$5,000	$1,105
1985	$3,215	$3,585	$5,623	$7,444		$5,226	$2,280
1986	$4,094	$2,415	$5,497	$7,631		$4,426	$1,250
1987	$0	$1,350	$5,595	$8,000		$3,940	$1,065
1988	$455	$1,775	$5,355	$5,770		$4,955	$1,580
1989	$0	$2,250	$4,085	$3,500		$5,930	$1,935
1990	$0	$2,140	$3,761	$3,290		$5,523	$1,601
1991	$6,925	$2,435	$5,543	$3,627		$5,884	$2,155
1992	$1,300	$2,700	$7,100	$3,600		$4,916	$5,300
1993	$2,080	$5,635	$5,517	$3,600			$4,520
1994	$2,597	$3,400	$6,466	$1,300			$6,403
1995	$5,977	$6,267	$4,620	$4,000			$5,090
1996	$8,700	$5,899	$0	$1,900			$5,200
1997	$9,818	$5,030	$0	$400			$5,900
1998	$5,600	$6,900	$4,387				$5,119
1999	$4,084	$4,934	$6,782				$4,150
2000	$1,475	$5,500	$7,025		$3,049		$3,405
2001	$2,700	$5,500	$5,600		$1,700		$4,745
2002	$3,000	$5,084	$5,336		$1,580		$4,111
2003	$4,163	$5,717			$5,915		$8,111
2004	$3,000	$6,000			$6,680		$5,226
2005	$3,534	$4,060			$6,788		$5,180
2006	$3,734	$4,128			$5,928		$3,592
Total	$189,854	$141,011	$121,661	$137,256	$31,640	$193,688	$320,094

Capital Equipment	Program Direction	Baca	Environmental Control	Geothermal Heat Pumps	Geopowering the West	Other	TOTAL
$704			$1,301			$2,958	$43,114
$1,500			$2,500			$2,300	$53,050
$2,500		$12,000	$3,600			$4,500	$106,200
$3,000	$663	$7,450	$516			$10,500	$145,668
$3,200	$1,100	$20,500	$1,300			$12,200	$147,700
$1,310	$2,376	$12,050	$2,600			$19,959	$156,631
$860	$1,600	$2,124	$500				$69,464
$250	$1,250					$5,963	$57,474
$0	$1,000					$100	$30,270
$400	$1,025					$900	$29,698
$481	$701						$26,495
$0	$780						$20,730
$0	$835						$20,725
$795	$826						$19,321
$426	$782						$17,523
$401	$889					$2,479	$30,338
$821	$1,000			$200			$26,937
$900	$1,000						$23,252
$873	$970		$1,000				$23,009
$886	$1,000		$967	$5,000		$4,000	$37,807
				$5,300		$2,400	$29,399
				$6,482		$2,000	$29,630
				$6,400		$288	$28,694
				$6,420		$1,780	$28,150
						$2,882	$23,336
					$1,600	$4,778	$26,623
					$3,200	$4,724	$27,035
					$3,521	$963	$28,390
					$2,738	$981	$24,625
					$3,128	$2,666	$25,356
					$2,658	$2,722	$22,762
$19,307	**$17,797**	**$54,124**	**$14,284**	**$29,802**	**$16,845**	**$92,043**	**$1,379,406**

Abbreviations & Acronyms

2-D	Two-dimensional
3-D	Three-dimensional
AEC	Atomic Energy Commission
AMG	Amargosa Desert
atm	Atmospheres
B/D, Bpd	Barrels per day
BHA	Bottom-hole assembly
BHT	Bottom-hole temperature
BHTV	Borehole televiewer
BPA	Bonneville Power Authority
BPM	Barrels per minute (1 barrel = 42 gallons)
BTC	Breakthrough curve
CCPA	Central California Power Agency
CFE	Comisión Federal de Electricidad (Mexico)
CT	Computer tomography
DAT	Division of Applied Technology, Atomic Energy Commission
DC	Direct current
DOE	United States Department of Energy
DOE BES	United States Department of Energy Office of Basic Energy Sciences
DOE/DGE	Division of Geothermal Energy of the United States Department of Energy
DVPP	Dixie Valley Power Partners
EDTA	Ethylenediaminetetraacetic acid
EGI	Energy & Geoscience Institute, University of Utah *(formerly the Earth Science Laboratory, University of Utah Research Institute)*
EGS	Enhanced Geothermal Systems
Eh	Oxidation/reduction potential
ELTF	Engineered-Lithology Test Facility
EM	Electromagnetic
Emf	Electromagnetic field
ENEL	Ente Nazionale per l'Energia Elettrica (Italy)
EOS	Equation-of-state
EPDM	Ethylene-propylene-diene monomer
EPRI	Electric Power Research Institute
ERDA	Energy Research and Development Administration
ESL/UURI	Earth Science Laboratory, University of Utah Research Institute *(now the Energy & Geoscience Institute)*
ESTSC	Energy Science and Technology Software Center, U.S. Department of Energy
ETCP	Energy Technology Collaboration Program, International Energy Agency
ExCo	Executive Committee, International Energy Agency
FMS	Formation microscanner
FTP	File transfer protocol
GEA	Geothermal Energy Association
GIA	Geothermal Implementing Agreement, International Energy Agency
gpm	Gallons per minute
GRC	Geothermal Resources Council
GRWSP	Geothermal Reservoir Well Stimulation Program
GTO	Geothermal Technology Organization
GTP	Geothermal Technologies Program
HDPE	High-density polyethylene
HDR	Hot Dry Rock
HEGF	High-energy gas fracturing
HPLC	High-performance liquid chromatography

HPS	Hybrid Power System
HR	Homogeneously rough-walled
HRDF	Hard-Rock Drilling Facility
HT	High-temperature
HTR	High-temperature reservoir
HWR	Hot wet rock
IA	Implementing Agreement
ICFT	Initial Closed-Loop Flow Test
IEA	International Energy Agency
IEA/GIA	International Energy Agency/ Geothermal Implementing Agreement
IFD	Integral Finite Difference
IGA	International Geothermal Association
IGT	Institute of Gas Technology *(formerly the Gas Research Institute)*
INL	Idaho National Laboratory *(formerly called INEL and INEEL)*
kh	Permeability-thickness product
kW	Kilowatt
L/s	Liters per second
LANL	Los Alamos National Laboratory
lb/ft	Pound per foot
lb/hr	Pound per hour
lb/yr	Pounds per year
LBNL	Lawrence Berkeley National Laboratory
LCTF	Lost Circulation Test Facility
LLNL	Lawrence Livermore National Laboratory
LTFT	Long-Term Flow Test
m	Meter
M	Magnitude
md	Millidarcy
MEQ	Microearthquake
mg/l	Milligrams per liter
MGD	Million gallons per day
MHF	Massive Hydraulic Fracturing
MIT	Massachusetts Institute of Technology
ml/min	Milliliters per minute
mm	Millimeter
mol%	Moles solute/100 moles of solution
MPa	Mega Pascal
MRFM	Modified rolling float meter
MT	Magnetotelluric
MTCM	Modified tortuous-channel model
MTR	Membrane Technology Research
MW	Megawatt
MWe	Megawatt-electric
MWt	Megawatt-thermal
NAPL	Nonaqueous phase liquid
NCEDC	Northern California Earthquake Data Center
NCG	Noncondensable gas
NCPA	Northern California Power Agency
NEDO	Japanese New Energy and Industrial Technology Development Organization
NCSN	Northern California Seismic Network
NSF	National Science Foundation
NTA	Nitrilotriacetate
ORNL	Oak Ridge National Laboratory
OSTI	Office of Scientific and Technical Information, United States Department of Energy
PBR	Polished bore receptacle
PERI	Princeton Energy Resources International, LLC
PEST	Parameter ESTimation
pH	Acidity
PKD	Parkfield (California)

ppm	Parts per million
psi	Pound per square inch
pss	Pseudo-steady state
PSU	Pennsylvania State University
PTC	Production Tax Credit
R&D	Research and Development
RPS	Renewable Portfolio Standard
RR	Randomly rough-walled
RVFT	Reservoir Verification Flow Test
SAIC	Science Applications International Corporation
SBIR	Small Business Innovation Research
SBTF	Single-Blow Test Facility
SC	Supercritical
scf	Standard cubic foot
SCF/STB	Standard cubic feet/Standard barrel
SE	Southeast
SEGEP	Lake County-Southeast Geysers Effluent Pipeline
SNL	Sandia National Laboratories
SP	Self-potential
SPME	Slid-phase micro-extraction
SRGRP	Santa Rosa Geothermal Reinjection Project
SWS	Shear-wave splitting
T	Temperature
T2STR	TOUGH2 code
Tcf	Trillion cubic feet
TD	Total depth
TDS	Total dissolved solids
TEOR	Thermal Enhanced Oil Recovery
Th	Thorium
THCM	Thermal-Hydro-Chemical-Mechanical
THM	Thermal-Hydraulic-Mechanical
THMC	Thermal–Hydrologic–Mechanical–Precipitation/dissolution
TVD	True vertical depth
UCSD	University of California at San Diego
UNC	University Of North Carolina
USGS	United States Geological Survey
UU	University of Utah
UURI	University of Utah Research Institute *(now the Energy and Geoscience Institute)*
VOC	Volatile organic compound
WBHX	Wellbore heat extraction
wt %	Weight percent

References Organized by Major Research Project Area

Literature developed from DOE's Geothermal Exploration Research program is very extensive, going well beyond the references cited herein. A complete listing is beyond the scope of this report, and has not been attempted. Instead, selected additional references organized by major research area are listed below.

Field Case Studies

Allis, R.G., Gettings, P., Isherwood, W.F., Chapman, D.S., 2001. Precision gravity changes at The Geysers geothermal reservoir, 1975 – 2000. In: Proceedings of the 26th Geothermal Reservoir Engineering Workshop, Stanford University, 10 pp.

Blackwell, D.D., Smith, R.P., Bergman, S., Goff, F., Kennedy, M., McKenna, J., Richards, M., Waibel, A., and Wannamaker, P., Description, Synthesis, and Interpretation of the Thermal Regime, Geology, Geochemistry and Geophysics of the Dixie Valley, Nevada Geothermal System; Nevada Bureau of Mining Geology Open File Report, 250 pp., in preparation 2009.

Blackwell, D.D., Smith, R.P., and Richards, M.C., Exploration and development at Dixie Valley, Nevada, Summary of DOE Studies, Proceedings of 32nd Workshop on Geothermal Reservoir Engineering, Stanford University, 83-98, 2007.

Bodvarsson, G.S. and Benson, S.M., 1983. A Summary of Well Testing at Lawrence Berkeley Laboratory, 1975-1982, Geothermal Resources Council Transactions, 7, 397-402.

Brikowski, T.H., 2000. Using isotopic alteration modeling to explore the natural state of The Geysers geothermal system, USA. In: Proceedings, World Geothermal Congress 2000, Japan, pp. 2045-2050.

Elkibbi, M. and Rial, J.A., 2003. Shear-Wave Splitting: An Efficient Tool to Detect 3D Fracture Patterns at The Geysers, California. In: Proceedings of the 28th Geothermal Reservoir Engineering Workshop, Stanford University, 7 pp.

Elkibbi, M., Yang, M., Rial, J.A., 2004. Imaging crack systems in The Geysers with shear-wave splitting. Geothermal Resources Council Transactions 28, 393-398.

Erden, D., Elkibbi, M., Rial, J.A., 2001. Shear wave splitting and fracture patterns at The Geysers (California) geothermal field. In: Proceedings of the 26th Geothermal Reservoir Engineering Workshop, Stanford University, 9 pp.

Gettings, P., Harris, R.N., Allis, R.G. , Chapman, D.S., 2002a. Gravity signals at The Geysers geothermal system. In: Proceedings of the 27th Geothermal Reservoir Engineering Workshop, Stanford University, 8 pp.

Gettings, P., Allis, R.G., Isherwood, W.F., Chapman, D.S., 2001. Reservoir monitoring at The Geysers with repeated high-precision gravity and GPS. Geothermal Resources Council Transactions 25, 631-634.

Gettings, P., Harris, R.N., Allis, R.G., Chapman, D.S., 2002. Gravity signals at The Geysers geothermal system. Geothermal Resources Council Transactions 26, 425-429.

Hulen, J.B., Norton, D.L., 2000. Wrench-fault and emplacement of The Geysers felsite. Geothermal Resources Council Transactions 24, 289-298.

Hulen, J.B., Norton, D.L., Moore, J.N., Beall, J.J.,Walters, M.A., 2001. Initial insights into the nature origin configuration and thermal-chemical evolution of the Aidlin steam reservoir Northwest Geysers steam field California. Geothermal Resources Council Trans 25, 345-352.

Lippmann, M.J. and Mañón, 1987. The Cerro Prieto Geothermal Field. Geothermal Science and Technology, 1, 1–38.

Lippmann, M.J., 1983. Overview of Cerro Prieto Studies. Geothermics, 12, 265–289.

Nielsen, D., Moore, J.N., 2000. The Deeper parts of The Geysers thermal system - Implications for heat recovery. Geothermal Resources Council Transactions 24, 299-302.

Proceedings, First Symposium on the Cerro Prieto Geothermal Field, Baja California, Mexico, September 20-22, 1978, San Diego, California. Lawrence Berkeley Laboratory Report LBL-7098, 456 pp.

Proceedings, Fourth Symposium on the Cerro Prieto Geothermal Field, Baja California, Mexico, August 10-12, 1982, Guadaljara, Jal., Mexico. Two-volume report issued by the Comisión Federal de Electricidad of Mexico, 845 pp.

Proceedings of the ENEL-ERDA Workshop. Geothermics 7 (2-4), 53-264.

Proceedings of the Larderello Workshop on Geothermal Resource Assessment and Reservoir Engineering, convened in the frame of the ENEL-ERDA Agreement, September 12-16, 1977, Larderello, Italy. Report issued by the Ente Nazionale per l'Energia Elettrica (ENEL), 428 pp.

Proceedings, Second DOE-ENEL Workshop for Cooperative Research in Geothermal Energy, October 20-23, 1980, Berkeley, California. Lawrence Berkeley Laboratory Report LBL-11555, 513 pp.

Proceedings, Second Symposium on the Cerro Prieto Geothermal Field, Baja California, Mexico, October 17-19, 1979, Mexicali, BCN, Mexico. Report issued by the Comisión Federal de Electricidad of Mexico, 638 pp.

Proceedings, Symposium in the Field of Geothermal Energy, 1989. April 4-5, 1989, San Diego, California. Report issued by the Comisión Federal de Electricidad of Mexico, 289 pp. plus plates.

Proceedings, Third Symposium on the Cerro Prieto Geothermal Field, Baja California, Mexico, 1981. Lawrence Berkeley Laboratory Report LBL-11967, 582 pp.

Pruess, K., Spycher, N., Kneafsey, T.J., 2007. Water injection as a means for reducing noncondensable and corrosive gases in steam produced from vapor-dominated reservoirs. In: Proceedings of the 32nd Geothermal Reservoir Engineering Workshop, Stanford University, 8 pp.

Pryfogle, P.A., 2000. Evaluation of biological methods used at The Geysers. Geothermal Resources Council Transactions 24, 311-315.

Schmitt, A.K., Grove, M., Harrison, T.M., Lovera, O., Hulen, J., Walters, M., 2002. Intrusion ages of the Geysers plutonic complex determined by ion microprobe U-Pb dating of zircon. Geothermal Resources Council Transactions 26, 375-378.

Special Issue on the Cerro Prieto Geothermal Field, 1979. Geothermics 8 (3/4), 145-281.

Special Issue on the Cerro Prieto Geothermal Field, 1980. Geothermics 9 (1/2), 1-220.

Special Issue on the Cerro Prieto Geothermal Field, 1981. Geothermics 10 (3/4), 145-276.

Special Issue on the Cerro Prieto Geothermal Field, 1984. Geothermics, 13 (1/2), 1-162.

Witherspoon, P.A., Alonso E.H., Lippmann, M.J., Mañón M.A., and Wollenberg, H.A., 1978. Mexican-American Cooperative Program at the Cerro Prieto Geothermal Field. Lawrence Berkeley Laboratory Report LBL-7095, Berkeley, California, 33 pp.

Hot Dry Rock

Armstead, H.C.H. and Tester, J.W., 1987, Heat Mining. London: E. and F.N. Spon, 478 pp.

Brown, D. W., 1991. Recent progress in HDR reservoir engineering, in The Geothermal Partnership—Industry, Utilities, and Government Meeting the Challenges of the 90's, Proceedings of Geothermal Energy Program Review IX (March 19–21, 1991: San Francisco, California). U. S. Department of Energy document CONF-9103105, pp. 153–157.

Brown, D. W., 1995. The US hot dry rock program—20 years of experience in reservoir testing, in Worldwide Utilization of Geothermal Energy: An Indigenous, Environmentally Benign Renewable Energy Resource, Proceedings of the World Geothermal Congress (May 18–31, 1995: Florence, Italy), International Geothermal Association, Inc., Auckland, New Zealand, vol. 4, pp. 2607–2611.

Duchane, D., 1993, Geothermal Energy, Encyclopedia of Chemical Technology, 12, 512-539, Wiley, NY.

Duffield, R.B., Nunz, G.J., Smith, M.C., and Wilson, M.G., 1981, "Hot Dry Rock", Geothermal Energy Development Program, Annual Report FY80, Los Alamos National Laboratory Report, LA-8855-HDR, 211 pp.

Slemmons, D.B., 1975. Fault activity and seismicity near the Los Alamos Scientific Laboratory Geothermal Test Site, Jemez Mountains, New Mexico, Los Alamos Scientific Laboratory report LA-59-11-MS, Los Alamos, NM.

Smith, M.C., Aamodt, R.L., Potter, R.M., and Brown, D.W., 1975, Man-made geothermal reservoirs, Proc. UN Geothermal Symposium, 3, 1781-1787, San Francisco, California.

Smith, R.L., Bailey, R.A., and Ross, C.S., 1970. Geologic Map of the Jemez Mountains, New Mexico, U. S. Geological Survey Miscellaneous Investigations Series Map No. I-571, Reston, VA.

Tester, J.W. and Albright, J.N., 1979, Hot dry rock energy extraction field test: 75 days of operation of a prototype reservoir at Fenton Hell, segment 2 of phase 1, Informal Report No. LA-7771-MS, Los Alamos National Laboratory, Los Alamos, NM.

Tester, J.W., Murphy, H.D., Grigsby, C.O., Potter, R.M., and Robinson, B.A., 1989, Fractured geothermal reservoir growth induced by heat extraction, SPE J. Reservoir Engineering, 3, 97-104.

Geopressured-Geothermal Energy Program

Bassiouni, Z. "Evaluation of Potential Geopressure Geothermal Test Sites in Southern Louisiana," Progress Report. DOE Contract No. DE-AS05- 76ET28465. April 1980.

Bebout, D.G. and Gutierrez, D.R. "Geopressured Geothermal Resource in Texas and Louisiana – Geological Constraints," Proceedings of the 5th Geopressured-Geothermal Energy Conference held in Baton Rouge, La. October 1981. Edited by Bebout and Bachman.

Bebout, D.G. "Regional and local geologic setting of the Technadril-Fenix and Scisson Department of Energy Gladys McCall #1 well site," Geopressured-Geothermal Energy Resource Appraisal. R. H. Wallace, Jr. ed. (1982).

Brown, W.M. 100,000 Quads of Natural Gas?, Research Memorandum #31, Report HI-2415/2-P, Hudson Institute, Inc., Croton-on-Hudson, NY, July 1976.

Dorfman, M.H. "Geopressured-geothermal energy and associated natural gas," Proceedings, Geothermal Energy Symposium, 11th Annual Energy-Source Technology Conference and Exhibit, New Orleans, Louisiana, American Society of Mechanical Engineers, Geothermal Resources Council, p. 97-101 (1988).

Doscher, T.M., et al. "The Numerical Simulation of the Effect of Critical Gas Saturation and Other Parameters on the Productivity of Methane From Geopressured Aquifers," paper SPE 8891 presented at the 1980 Annual California Regional Meeting of the Society of Petroleum Engineers of AIME held in Los Angeles, California. April 9-11.

Eaton Operating Company, Inc. Final Report (1990).

Griggs, J. "A Re-evaluation of Geopressured-Geothermal Aquifers as an Energy Source," Proceedings, 30th Workshop on Geothermal Reservoir Engineering, Stanford University SGP-TR-176 (2004).

Hawkins, M.F. and Parmigiano, J.M. "Geopressured Water as an Energy Source," paper SPE 4725. Publication date unkown. Hickel, W. J. "Geothermal Energy-A National Proposal for Geothermal Resources Research", Univ. of Alaska, 1973.

Hise, B.R. "Natural Gas from Geopressured Aquifers," pp.41-63 in Natural Gas from Unconventional Geologic Sources, National Academy of Sciences, Washington, DC, 1976.

Hottman, C.E. "Method for producing a source of energy from an overpressured formation," U.S. Patent 3,258,069 (1966).

Isokari, O.F. "Natural Gas Production from Geothermal Geopressured Aquifers", paper SPE 6037 presented at the 1976 Annual Fall Technical Conference and Exhibition held in New Orleans, Louisiana. October 3-6.

John, C.J., Maciasz, G., and Harder, B.J. "Gulf Coast Geopressured-Geothermal Program Summary Report Compilation," Volumes 1- 4, Work performed under U.S. Department of Energy Contract No. DE-FG07-95ID13366, June 1998.

John, C.J. "Geology of the Gladys McCall geopressured-geothermal prospect, Cameron Parish, Louisiana," Journal of Energy Resources Technology, v. 110, p. 255-261 (1988).

Jones, P.H. "Natural Gas Resources of the Geopressured Zones in the Northern Gulf of Mexico Basin," pp.17-23 in Natural Gas from Unconventional Geologic Sources, National Academy of Sciences, Washington, DC, 1976.

Kelkar, S.M., Cooley, C.H., and Schatz, J.F. "Mechanical Properties of Geopressure Core and Their Influence on Reservoir Performance: TF& S/OE Gladys McCall No.1 Well," paper SPE 12191 presented at the 1983 Annual Technical Conference and Exhibition held in San Francisco, CA. October 5-8.

Klauzinski, R.Z. "Testing of Six 'Wells of Opportunity' During 1980 and 1981," Proceedings of the 5th Geopressured-Geothermal Energy Conference held in Baton Rouge, La. October 1981. Edited by Bebout and Bachman.

Knapp, R.M., et al. "An Analysis of Production from Geopressured Geothermal Aquifers," paper SPE 6825 presented at the 1977 Annual Fall Technical Conference and Exhibition held in Denver, Colorado. October 9-12.

Lee, K.S. "Analysis on the Depletion and Recovery Behavior of a Geopressured/Geothermal Reservoir," paper SPE 64516 presented at the 2000 SPE Asia Pacific Oil and Gas Conference and Exhibition held in Brisbane, Australia. October 16-18.

McCoy, R.L., Hartsock, J.H., and Dobson, R.J. "Preliminary Results of the Wells-of-Opportunity Program Geopressured-Geothermal Testing Program," paper SPE 8958 presented at the 1980 SPE/DOE Symposium on Unconventional Gas Recovery held in Pittsburgh, PA. May 18-21.

McMullan, J.H. and Bassiouni, Z. "Prediction of Maximum Flow Rates From Geopressured Aquifers," paper SPE 10282 presented at the 1981 Annual Fall Technical Conference and Exhibition held in San Antonio, Texas. October 5-7.

Negus-de Wys. "The geopressured-geothermal resource, research and use," Proceedings, The National Energy Strategy – The Role of Geothermal Technology Development, San Francisco, California, 18-20 April, 1990. OSTI Identifier: OSTI6886699 (1990).

Ocamb, R.D. "Growth Faults of South Louisiana: Gulf Coast," Association of Geological Societies Transactions, v.11, p. 139-175 (1961).

Papadopulos, S.S., et al. "Assessment of Onhsore Geopressured-Geothermal Resources in the Northern Gulf of Mexico Basin," pp.125-46 in Assessment of Geothermal Resources of the United States – 1975, D.E. White and D.L. Williams, eds., U.S. Geological Survey Circular 726, 1975.

Petzet, G. A. "Partial U.S. Oil, Gas Resource Volumes Termed 'Astonishing," Oil & Gas Journal. March 16, 1995.

Plum, M.M. et al. “Economic review of the geopressured-geothermal resource with recommendations,” U.S. Department of Energy Technical Report, EGG-2581, OSTI 5231635, p. 20 (1989).

Quitzau, R. and Bassiouni, Z. “The Possible Impact of the Geopressure Resource on Conventional Oil and Gas Exploration,” paper SPE 10281 presented at the 1981 Annual Fall Technical Conference and Exhibition in San Antonio, Texas. October 5-7.

Randolph, P.L. “Natural Gas From Geopressured Aquifers?” presented at the 1977 Annual Fall Technical Conference and Exhibition held in Denver, Colorado. October 9-12.

Rogers, L.A., Randolph, P.L., Eaton, B.A. and Meahl, T.E. “The DOE Gladys McCall Geopressure-Geothermal Gas/Brine Well Test: Summary of Well Test Results,” paper SPE 21485 presented at the 1991 SPE Gas Technology Symposium held in Houston, TX. January 23-25.

Southwest Research Institute, “Geopressured Energy Availability,” Electric Power Research Institute, EPRI AP-1457, Project 1272-1, July (1980).

Strongin, O. “Identification of Geopressured Occurences Outside of the Gulf Coast, Phase II,” Final Report, Science Application, Inc., McLean, VA. 22102, Prepared for DOE, Nevada Operations Office, Las Vegas, NV 89114, Under Contract No. DE-AC08-80NV10133 (1981).

Swanson, R.K., Bernard, W.J., Osoba, J.S. “A Summary of the Geothermal and Methane Production Potential of U.S. Gulf Coast Geopressured Zones From Test Well Data,” Journal of Petroleum Technology. December 1986. pp. 1365-1370.

Tomsor, M.B, Rogers, L.A., Varughese, K., Prestwich, S.M, Waggett, G.G., Salimi, M.H. “Use of Inhibitors for Scale Control in Brine-Producing Gas and Oil Wells,” paper SPE 15457 presented at 1986 Annual Technical Conference and Exhibition held in New Orleans, LA. October 5-8.

Wallace, R.H., et al. “Assessment of Geopressured-Geothermal Resources in the Northern Gulf of Mexico Basin,” pp.132-55 in Assessment of Geothermal Resources of the United States – 1978, D.E. White and D.L. Williams, eds., U.S. Geological Survey Circular 790, 1979.

Wallace, R.H., Jr., editor. “Geopressured-Geothermal Energy Resource Appraisal,” Louisiana Geological Survey Guidebook Series No. 2, p. 112 (1982).

Westhusing, K. “Department of Energy Geopressured Geothermal Program,” Opening Comments. Proceedings of the 5th Geopressured-Geothermal Energy Conference held in Baton Rouge, LA. October 1981. Edited by Bebout and Bachman.

Wrighton, F. “An Economic Overview of Geopressured Solution Gas,” in Proceedings of the 5th Geopressured Geothermal Energy Conference. Baton Rouge, LA. 1981. Edited by Bebout and Bachman.

Modeling of Geothermal Systems

Adams, M.C., 2001. A comparison of two multiple-tracer tests conducted at The Geysers. In: Proceedings of the 26th Geothermal Reservoir Engineering Workshop, Stanford University, 7 pp.

Allis, R. and Shook, G. M., 1999. An alternative mechanism for the formation of The Geysers vapor-dominated reservoir: Proceedings, Twenty-Fourth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 25-27, 1999, SGP-TR-162.

Aunzo, Z.P., Bjornsson, G., Bodvarsson, G.S., 1991. Wellbore models GWELL, GWNACL, and HOLA user’s guide. Lawrence Berkeley Laboratory In: Report LBL-31428, Berkeley, California, 102 pp.

Battistelli, A., Calore, C., K. Pruess. The Simulator TOUGH2/EWASG for Modeling Geothermal Reservoirs with Brines and Noncondensable Gas, Geothermics, Vol. 26, No. 4, pp. 437 - 464, 1997.

Beall, J.J., Adams, M.C., Smith J.L.B., 2001. Geysers reservoir dry out and partial resaturation evidenced by twenty-five years of tracer tests. Geothermal Resources Council Transactions 25, 725-729.

Bjornsson, G. and Bodvarsson, G.S., 1987. A multi-feedzone wellbore simulator. Geothermal Resources Council Transaction, 11, pp. 503–507.

Bodvarsson, G.S., Pruess, K., Stefansson, V., Eliasson, E.T. The Krafla Geothermal Field, Iceland, 2. The Natural State of the System, Water Resources Research, 20 (11), 1531-1544, 1984b.

Bodvarsson, G.S., Pruess, K., Stefansson, V., Eliasson, E.T. The Krafla Geothermal Field, Iceland, 3. The Generating Capacity of the Field, Water Resources Research, 20 (11), 1545-1559, 1984c.

Brownell, D.H., Jr., S.K. Garg and J.W. Pritchett. Governing Equations for Geothermal Reservoirs, Water Resources Research, 13 (6), December 1977.

Duan, Z., Möller, N., Weare J. A General Equation of State for Supercritical Fluid Mixtures and Molecular Dynamics Simulations for Mixture PVTX Properties, Geochim. Cosmochim. Acta, Vol. 60, pp. 1209–1216, 1996.

Duan, Z., Möller N., Weare J. Equation of State for the NaCl-H2O-CO2 System: Prediction of Phase Equlibria and Volumetric Properties, Geochim. Cosmochim. Acta, Vol. 59, pp. 2869–2882, 1995.

Finsterle, S. iTOUGH2 User's Guide, Lawrence Berkeley National Laboratory Report LBNL-40040, Berkeley, California, January 1999.

Finsterle, S. and Pruess, K. Solving the Estimation-Identification Problem in Two-Phase Flow Modeling. Water Resources Res., Vol. 31, No. 4, pp. 913-924, April 1995.

Geothermics Vol. 30, No. 2/3 (2001) Special issue: The Geysers Coring Project and The Geysers/Clear Lake igneous-geothermal regime (J.B. Hulen, editor), pp. 165-394.

Ghassemi, A., Tarasovs, A., and A.D.-H Cheng. Integral Equation Solution of Heat Extraction Induced Thermal Stress in Enhanced Geothermal Reservoirs, Int. J. Num. & Anal. Methods in Geomechanics, Vol. 29, pp. 829-844, 2005.

Gruszkiewicz, M., Horita, J., Simonson, J.M. Mesmer, R.E., 2000. High-temperature water adsorption on geothermal reservoir rocks. In: Proceedings, World Geothermal Congress 2000, Japan, pp. 2585-2590.

Hadgu, T., Zimmerman, R.W. and Bodvarsson, G.S., 1995. Coupled reservoir-wellbore simulation of geothermal reservoir behavior. Geothermics 24, 145-166.

Kratt et al., 2006. Geothermal exploration with Hymap hyperspectral data at Brady–Desert Peak, Nevada, Remote Sensing of Environment 104, 313–324.

Li, K., Horne, R.N., 2003. Direct Measurement of In-Situ Water Saturation in The Geysers Rock In: Proceedings of the 28th Geothermal Reservoir Engineering Workshop, Stanford University, 7 pp.

Miller, C.W., 1980. Wellbore user's manual. Lawrence Berkeley Laboratory, Report LBL-10910, Berkeley, California, 48 pp.

Möller, N., Greenberg, J.P., and Weare, J.H. Computer Modeling for Geothermal Systems: Predicting Carbonate and Silica Scale Formation, CO2 Breakout and H2S Exchange, Transport in Porous Media, Vol. 33, pp. 173-204, 1998.

Moridis, G.J., Kowalsky, M.B., and Pruess, K. Depressurization-Induced Gas Production From Class 1 Hydrate Deposits, SPE Reservoir Evaluation & Engineering, October 2007.

O'Sullivan, M.J., Pruess, K., and Lippmann, M.J. State of the Art of Geothermal Reservoir Simulation, Geothermics, Vol. 30, No. 4, pp. 395-429, 2001.

Powell, T., Li, K., 2003. A Depletion Mechanism for the Behavior of Noncondensable Gases at The Geysers. Geothermal Resources Council Transactions 27, 771-778.

Pritchett, J.W. Dry-Steam Wellhead Discharges From Liquid-Dominated Geothermal Reservoirs: A Result of Coupled Nonequilibrium Multiphase Fluid and Heat Flow Through Fractured Rock, B. Faybishenko, P.A. Witherspoon and J. Gale (eds.), Dynamics of Fluids and Transport in Fractured Rock, Geophysical Monograph 162, pp. 175–181, American Geophysical Union, Washington, DC, 2005.

Pruess K. and Spycher, N. ECO2N – A Fluid Property Module for the TOUGH2 Code for Studies of CO2 Storage in Saline Aquifers, Energy Conversion and Management, Vol. 48, No. 6, pp. 1761–1767, doi:10.1016/j.enconman.2007.01.016, 2007.

Pruess, K. The TOUGH Codes—A Family of Simulation Tools for Multiphase Flow and Transport Processes in Permeable Media, Vadose Zone J., Vol. 3, pp. 738-746, 2004.

Pruess, K. TOUGH2 - A General Purpose Numerical Simulator for Multiphase Fluid and Heat Flow, Lawrence Berkeley Laboratory Report LBL-29400, Lawrence Berkeley Laboratory, Berkeley, California, May 1991.

Pruess, K. and Battistelli, A. TMVOC, a Numerical Simulator for Three-Phase Non-Isothermal Flows of Multicomponent Hydrocarbon Mixtures in Saturated-Unsaturated Heterogeneous Media, Lawrence Berkeley National Laboratory Report LBNL-49375, April 2002.

Pruess, K. and Schroeder, R.C. SHAFT 79 User's Manual, Report No. LBL-10861, Lawrence Berkeley Laboratory, Berkeley, California, March 1980.

Pruess, K. and Narasimhan, T.N. A Practical Method for Modeling Fluid and Heat Flow in Fractured Porous Media, Soc. Pet. Eng. J., 25 (1), 14-26, February 1985.

Pruess, K. SHAFT, MULKOM, TOUGH: A Set of Numerical Simulators for Multiphase Fluid and Heat Flow, Geotermia, Rev. Mex. Geoenergia, 4 (1), 185–202, Lawrence Berkeley Laboratory Report LBL-24430, 1988.

Pruess, K. TOUGH User's Guide, Nuclear Regulatory Commission Report NUREG/CR-4645; also Lawrence Berkeley Laboratory Report No. LBL-20700, 1987.

Pruess, K., Simmons, A., Wu, Y.S., and G. Moridis. TOUGH2 Software Qualification. Lawrence Berkeley National Laboratory Report LBL-38383, February 1996.

Pruess, K., Oldenburg, C., and Moridis, G. TOUGH2 User's Guide, Version 2.0, Lawrence Berkeley National Laboratory Report LBNL-43134, Berkeley, California, November 1999.

Pruess, K., Bodvarsson, G.S., Stefansson, V., and Eliasson, E.T. The Krafla Geothermal Field, Iceland, 4, History Match and Prediction of Individual Well Performance, Water Resour. Res., Vol. 20, No. 11, pp. 1561-1584, 1984.

Pruess, K., S. Yabusaki, C. Steefel and P. Lichtner. Fluid Flow, Heat Transfer, and Solute Transport at Nuclear Waste Storage Tanks in the Hanford Vadose Zone, Vadose Zone J., Vol. 1, No. 1-2, pp. 68-88, August 2002.

Reyes, J.L.P., Horne, R.N., 2002. Analysis of The Geysers well field performance data to infer in-situ water saturation. Geothermal Resources Council Transactions 26. 107-112.

Reyes, J.L.P. and Horne, R.N., 2003. Estimating Water Saturation at The Geysers Based on Historical Pressure/Temperature Production Data. In: Proceedings of the 28th Geothermal Reservoir Engineering Workshop, Stanford University, 10 pp.

Reyes, J.L.P., Li, K., Horne, R.N., 2004. New Decline Curve Analysis Method Applied to The Geysers. In: Proceedings of the 29th Geothermal Reservoir Engineering Workshop, Stanford University, 8 pp.

Rick Allis, 2000, Insights on the formation of vapor-dominated geothermal systems: Proceedings, World Geothermal Congress 2000, Kyushu - Tohoku, Japan, May 28 - June 10, 2000.

SGP (Stanford Geothermal Program). Proceedings, Special Panel on Geothermal Model Intercomparison Study, Report SGP-TR-42, Stanford University, Stanford, California, 1980.

Shan, C. and Pruess, R., 2003. Numerical Simulation of Noble Gases as Natural Tracers for Injection Returns and Reservoir Processes in Vapor-Dominated Systems. In: Proceedings of the 28th Geothermal Reservoir Engineering Workshop, Stanford University, 8 pp.

Shook, G.M. and Faulder, D.D., 1991. Analysis of reinjection strategies for The Geysers: Proceedings, Sixteenth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 23-25, 1991, SGP-TR-134.

Shook, G.M., 1993. Numerical Investigations into the formation of a high temperature reservoir: Proceedings, Eighteenth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 26-28, 1993, SGP-TR-145.

Stanford Geothermal Program (ed.), Proceedings of the Special Panel on Geothermal Model Intercomparison Study. Report: SGP-TR42. Also presented at: 6th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, December 16-18, 1980.

Truesdell, A.H. and Shook, G.M., 1997. Effects of injection into the high-temperature reservoir of the NW Geysers - a cautionary tale: Proceedings, Twenty-Second Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 27-29, 1997, SGP-TR-155.

Weare, J.H. Models of Mineral Solubility in Concentrated Brines with Application to Field Observations, Rev. in Mineralogy, Vol. 17, pp. 143-176, 1987.

Xu, T. and K. Pruess. Modeling Multiphase Non-isothermal Fluid Flow and Reactive Geochemical Transport in Variably Saturated Fractured Rocks: 1. Methodology, American Journal of Science, Vol. 301, pp. 16-33, 2001.

Geoscience Support Projects

Adams, M.C., 1985. Tracer stability and chemical changes in an injected geothermal fluid during injection-backflow testing at the East Mesa geothermal field: Tenth Workshop on Geothermal Reservoir Engineering, Stanford Univ., p 247 252.

Adams, M.C., 1997. New tracers take on The Geysers: Geothermal Technologies, v. 2, no. 4, p. 1-2.

Adams, M.C., 2001. A comparison of two multiple-tracer tests conducted at The Geysers: Twenty-Sixth Workshop on Geothermal Reservoir Engineering, Stanford, California.

Adams, M.C. and Kilbourn, P.M., 2000. Thermal stability of the vapor-phase tracer R-134a: Twenty-Fifth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford California.

Adams, M.C. and McPherson, P., 1998. Gas tracers for geothermal systems: American Association of Petroleum Geologists, Annual Meeting, Salt Lake City.

Adams, M.C. and Moore, J.N., 1985, Development and application of tracers: examples of field and experimental studies: Univ. of Utah Research Inst. Rept., p. 6.

Adams, M.C., Beall, J.J., Hirtz, P. Koenig, B.A., and Smith, J.L. Bill, 1999. Tracing effluent injection into the SE Geysers – a progress report: Transactions, Geothermal Resources Council, p. 341-345.

Adams, M.C., Beall, J.J., Enedy, S.L., Hirtz, P.N., Kilbourn, P., Koenig, B.A., Kunzman, R., Smith, J.L.B. (2001). Hydrofluorocarbons as geothermal vapor-phase tracers. Geothermics 30, 747-775.

Adams, M.C., Benoit, W.R., Doughty, C., Bodvarsson, G.S., and Moore, J.N., 1989, The Dixie Valley, Nevada tracer test: Geothermal Resources Council, Transactions, vol. 13, p. 215-220.

Adams, M.C., Fabry, L., and Moore, J. N., 1990. Comparative study of high performance liquid chromatographic parameters used for the analysis of carboxylic and sulfonic acid geothermal tracers: University of Utah Research Institute, Earth Science Laboratory Rept., ESL-89013-TR, DOE/ID/12489-48.

Adams, M.C., Moore, J.N., and Wright, P.M., 1989. The use of tracers to analyze the effects of reinjection into fractured geothermal reservoirs: Proceedings of the 1989 International Symposium on Class I and II Injection Well Technology.

Adams, M.C., Moore, J.N., Fabry, L., and Ahn, A.H., 1992. Thermal stabilities of aromatic acids as geothermal tracers: Geothermics, vol. 21, p. 323-339.

Adams, M.C., Yamada, Y., Yagi, M., Kondo, T., and Wada, T., 2000b. Stability of methanol, propanol, and SF6 as high-temperature tracers: World Geothermal Congress, p. 3015-3019.

Adams, M.C. and Davis, J., 1990. Tracer studies I-thermal decay kinetics of fluorescein: University of Utah Research Institute, Earth Science Laboratory Rept., ESL-89038-TR, DOE/ID/12489-66.

Adams, M.C. and Moore, J.N., 1986. Development and Application of Tracers: Examples of Field and Experimental Studies: Geothermal Injection Technology Program Annual Progress Report, FY86, pp. 35-41: University of Utah Research Institute, Earth Science Laboratory Rept., joint publication with the Idaho National Engineering Laboratory, Rept. No. EGG-2445.

Adams, M.C. et al., 2004. Alcohols as tracers, Twenty-Ninth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California.

Adams, M.C., 1992. Tracing and monitoring reinjection fluids: United Nations Workshop on Reinjection of Geothermal Fluids in Volcanic Environments, Costa Rica.

Adams, M.C., 1993. Geothermal tracer development: U.S. Department of Energy Geothermal Reservoir Technology Research Program, Abstracts of Selected Research Projects Rept. DOE/CE-0397, March 1993, p. 62-67.

Adams, M.C., 1993. Geysers tracers: U.S. Department of Energy Geothermal Reservoir Technology Research Program, Abstracts of Selected Research Projects Rept. DOE/CE-0397, March 1993, p. 101-104.

Adams, M.C., 2004. Use of Naturally-Occurring Tracers to Monitor Two-Phase Conditions in the Coso Reservoir, Twenty-Ninth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California.

Adams, M.C., Ahn, J.H., Bentley, H., Moore, J.N., and Veggeberg, S., 1986, Derivatized hydrocarbons as geothermal tracers: Geothermal Resources Council, Transactions, vol. 10, p. 415-420.

Adams, M.C., Ahn, J.H., Bentley, H., Moore, J.N., and Veggeberg, S., 1986, Tracer developments — Results of experimental studies: in Proceedings, 11th Workshop on Geothermal Reservoir Engineering, Stanford University, p. 97-102.

Adams, M.C. and Davis, J., 1991. Kinetics of fluorescein decay and its application as geothermal tracer: Geothermics, vol. 20, p. 53-66.

Adams, M.C., Beall, J.J., Enedy, S.L., and Hirtz, P., 1991. The application of halogenated alkanes as vapor-phase tracers: A field test in the Southeast Geysers: Geothermal Resources Council, Transactions, vol. 15, p. 457-463.

Adams, M.C., Beall, J.J., Enedy, S.L., Hirtz, P.N., Kilbourn, P., Koenig, B.A., Kunzman, R., and Smith, J.L.B., 2001. Hydrofluorocarbons as geothermal vapor-phase tracers. Geothermics 30, 747-775.

Adams, M.C., Moore, J.M., and Hirtz, P., 1991. Preliminary assessment of halogenated alkanes as vapor-phase tracers: Sixteenth Workshop on Geothermal Reservoir Engineering, Stanford University, p. 57-62.

Adams, M.C., Moore, J.N., and Fabry, L., 1990. Stability and use of organic compounds as geothermal tracers: University of Utah Research Institute, Earth Science Laboratory Rept., ESL-89015-TR, DOE/ID/12489-50.

Aquilina, L., Rose, P.E., Vaute, L., Brach, M., Gentier, S., Jeannot, R., Jacquot, Audigane, P., Tran-Viet, T., Jung, R., Baumgaertner, J., Baria, R., and Gerard, A., 1998. A tracer test at the Soultz-sous-Forets Hot Dry Rock geothermal site: Proc. Twenty-Third Workshop on Geothermal Reservoir Engineering, Stanford University, SGP-TR-158, 343-347.

Beall, J.J., Adams, M.C., and Hirtz, P.N., 1998. Evaluation of R-134a as an injection tracer in the Southeast Geysers: Geothermal Resources Council, p. 569-573.

Beall, J.J., Adams, M.C., and Smith, J.L. Bill, 2001. Geysers reservoir dry out and partial restoration evidenced by twenty-five years of tracer tests: Geothermal Resources Council, Transactions, in prep.

Beall, J.J., Adams, M.C., and Hirtz, P.N., 1994. R-13 tracing of injection in The Geysers: Geothermal Resources Council, Transactions, vol. 18, p. 151-159.

Beneseth, P., Palmer D.A., and Weslowski D.J., 1997. The aqueous chemistry of aluminum: A new approach to high temperature solubility measurements, Geothermics, 26, 465-481.

Blankenship, D.A., Mansure, A.J., Finger, J.T., Jacobson, R.D., and Knudsen, S.D. Update on a Diagnostics-While-Drilling (DWD) System to Assist in the Development of Geothermal Wells, Geothermal Resources Council Transactions, Vol. 28, pp. 153–157, Geothermal Resources Council, 2004.

Bloomfield, K.K., Moore, J.N., 2003. Modeling hydrofluorocarbon compounds as geothermal tracers: Geothermics, v. 32, p. 203-218.

Bloomfield, K.K., Moore, J.N., Adams, M.C., and Sperry, T.L., 2001. Tracer test design and sensitivity studies of the Cove Fort geothermal resource tracer test. Transactions, Geothermal Resource Council 25.

Boitnott, G.N. Core Analysis for the Development and Constraint of Physical Models of Geothermal Reservoirs, Geothermal Resources Council Transactions, Vol. 26, pp. 387-392, Geothermal Resources Council, 2002.

Boitnott, G.N. and Hulen, J.B. Petrographic Controls on Electrical Properties of Core Samples from the Awibengkok Geothermal Field, Indonesia, Geothermal Resources Council Transactions, Vol. 25, pp. 391–394, Geothermal Resources Council, 2001.

Boitnott, G.N. and Boyd P.J. Permeability, Electrical Impedance, and Acoustic Velocities on Reservoir Rocks from The Geysers Geothermal Field, Proceedings, Twenty-First Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, 1996.

Brantley S., Crerar D., Möller N., and Weare, J. H., 1984. Geochemistry of a marine evaporite: Bocana de Virilla, Peru. J. Sediment. Petrol. 54, 447-462.

Capuano, R. M., Adams, M. C., and Wright, P. M., 1983. Tracer recovery and mixing from two geothermal injection-backflow studies: Ninth Workshop on Geothermal Reservoir Engineering, Stanford University, p. 299-304.

Chen C., Li, K., and Horne, R.N. Difference Between Steam-Water and Air-Water Relative Permeabilities in Fractures, Geothermal Resources Council Transactions, Vol. 27, pp. 793-800, Geothermal Resources Council, 2003.

Christov, C. and Möller, N., 2004a. A chemical equilibrium model of solution behavior and solubility in the H-Na-K-Ca-OH-Cl-HSO4-SO4-H2O system to high concentration and temperature. Geochimica Et Cosmochimica Acta 68(18), 3717-3739.

Christov, C. and Möller, N., 2004b. Chemical equilibrium model of solution behavior and solubility in the H-Na-K-OH-Cl-HSO4-SO4-H2O system to high concentration and temperature. Geochimica Et Cosmochimica Acta 68(6), 1309-1331.

Cole, D.R., Riciputi, L.R., Horita, J., and Chacko, T., 1998. Stable isotope exchange equilibria and kinetics in mineral-fluid systems. In: Proceedings, 9th International Symposium on Water-Rock Interaction, WRI-9, G.B. Arehart and J.R. Hulston, eds. A.A. Balkema Pub., 827-830.

Duan, Z.H., Möller, N., and Weare, J.H., 1992b. An equation of state for the CH4-CO2-H2O System: I. Pure systems from 0 to 1000ºC and 0 to 8000 bar. Geochimica Et Cosmochimica Acta 56(7), 2605-2617.

Duan, Z.H., Möller, N., and Weare, J.H., 1992c. An equation of state for the CH4-CO2-H2O System: II. Mixtures from 50 to 1000ºC and 0 to 1000 bar. Geochimica Et Cosmochimica Acta 56(7), 2619-2631.

Duan, Z.H., Möller, N., and Weare, J.H., 1992d. Molecular dynamics simulation of PVT properties of geological fluids and a general equation of state of nonpolar and weakly polar gases up to 2000 K and 20,000 bar. Geochimica Et Cosmochimica Acta 56(10), 3839-3845.

Duan, Z.H., Möller, N., and Weare, J.H., 1995a. Equation of state for the NaCl-H2O-CO2 System: Prediction of phase equilibria and volumetric properties. Geochimica Et Cosmochimica Acta 59(14), 2869-2882.

Duan, Z.H., Möller, N., and Weare, J.H., 1995b. Measurement of the PVT properties of water to 25 Kbars and 1600ºC from synthetic fluid inclusions in corundum - comment. Geochimica Et Cosmochimica Acta 59(12), 2639-2639.

Duan, Z.H., Möller, N., and Weare, J.H., 1995c. Molecular dynamics equation of state for nonpolar geochemical fluids. Geochimica Et Cosmochimica Acta 59(8), 1533-1538.

Duan, Z.H., Möller, N., and Weare, J.H., 1995d. Molecular dynamics simulation of water properties using RWK2 potential - from clusters to bulk water. Geochimica Et Cosmochimica Acta 59(16), 3273-3283.

Duan, Z.H., Möller, N., and Weare, J.H., 1996b. Equation of state for the NH3-H2O system. Journal of Solution Chemistry 25(1), 43-50.

Duan, Z.H., Möller, N., and Weare, J.H., 1996c. A general equation of state for supercritical fluid mixtures and molecular dynamics simulation of mixture PVTX properties. Geochimica Et Cosmochimica Acta 60(7), 1209-1216.

Duan, Z.H., Möller, N., and Weare, J.H., 1996d. Prediction of the solubility of H2S in NaCl aqueous Solution: an equation of state approach. Chemical Geology 130(1-2), 15-20.

Duan, Z.H., Möller, N., and Weare, J.H., 2000. Accurate prediction of the thermodynamic properties of fluids in the system H2O-CO2-CH4-N2 up to 2000 K and 100 kbar from a corresponding states/one fluid equation of state. Geochimica Et Cosmochimica Acta 64(6), 1069-1075.

Duan, Z.H., Möller, N., and Weare, J.H., 2003. Equations of state for the NaCl-H2O-CH4 system and the NaCl-H2O-CO2-CH4 system: Phase equilibria and volumetric properties above 573 K. Geochimica Et Cosmochimica Acta 67(4), 671-680.

Duan, Z.H., Möller, N., and Weare, J.H., 2004. Gibbs ensemble simulations of vapor/liquid equilibrium using the flexible RWK2 water potential. Journal of Physical Chemistry B 108(52), 20303-20309.

Duan, Z.H., Möller N., Derocher, T., and Weare, J.H., 1996a. Prediction of boiling, scaling and formation conditions in geothermal reservoirs using computer programs TEQUIL and GEOFLUIDS. Geothermics 25(6), 663-678.

Duan, Z.H., Möller, N., Greenberg, J., and Weare, J.H., 1992a. The prediction of methane solubility in natural waters to high ionic strength from 0 to 250ºC and from 0 to 1600 bar. Geochimica Et Cosmochimica Acta 56(4), 1451-1460.

Duan, Z., Möller, N., and Weare, J.H., 2001. Monte Carlo Gibbs ensemble simulation of phase equilibria of the RWK2 water. Abstracts of Papers - American Chemical Society.

Duan, Z., Möller, N., and Weare, J.H., 2006. A high temperature equation of state for the H2O-CaC1(2) and H2O-MgC1(2) systems. Geochimica Et Cosmochimica Acta 70(15), 3765-3777.

Elkibbi, M., Yang M., and Rial, J.A. Imaging Crack Systems in The Geysers with Shear-Wave Splitting, Geothermal Resources Council Transactions, Vol. 28, pp. 393–398, Geothermal Resources Council, 2004.

Felmy, A.R. and Weare, J.H., 1986. The prediction of borate mineral equilibria in natural waters: application to Searles Lake, California. Geochimica Et Cosmochimica Acta 50, 2771-2783.

Felmy, A.R. and Weare, J.H., 1991a. Calculation of Multicomponent Ionic Diffusion From Zero to High Concentration .1. the System Na-K-Ca-Mg-Cl-SO4-H2O At 25-Degrees-C. Geochimica Et Cosmochimica Acta 55(1), 113-131.

Felmy, A.R. and Weare, J. H., 1991b. Calculation of Multicomponent Ionic Diffusion From Zero to High Concentration .2. Inclusion of Associated Ion Species. Geochimica Et Cosmochimica Acta 55(1), 133-144.

Ginosar, D.M., Maxfield, B.T., McMurtrey, R.D., Rollins, H.W., Shook, G.M, 2005. The effect of moisture content on retention of fluorocarbon tracers on sand: Geothermics, v. 34, p. 47-60.

Greenberg, J.P., Weare, J.H., and Harvie, C.E., 1985. An equilibrium computation algorithm for complex highly nonideal systems. Application to silicate phase equilibria. High Temperature Science 20, 141-162.

Gruszkiewicz, M.S., Horita, J., Simonson, J.M., and Mesmer, R.E. Water Adsorption at High Temperature on Core Samples from The Geysers Geothermal Field, Proceedings, Twenty-Third Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, 1998.

Gruszkiewicz, M.S., Horita, J., Simonson, J.M., Mesmer, R.E., and Hulen, J.B. Water Adsorption at High Temperature on Core Samples from The Geysers Geothermal Field, California, USA, Geothermics, Vol. 30, No. 203, pp. 269–302, 2001.

Harvie, C., Greenberg J.P., and Weare, J.H., 1987. A chemical equilibrium algorithm for highly non-ideal multiphase systems: Free energy minimization. Geochimica Et Cosmochimica Acta 51, 1045-1057.

Harvie, C., Möller, N., and Weare, J., 1984. The prediction of mineral solubilities in natural waters: The Na-K-Mg-Ca-H-Cl-SO4-OH-HCO3-CO3-CO2-H2O system from zero to high concentration at 25 C. Geochimica Et Cosmochimica Acta 48, 723-751.

Hirtz, P., Lovekin, J., Copp, J., Buck, C., and Adams, M.C., 1993. Enthalpy and mass flowrate measurements for two-phase geothermal production by tracer dilution techniques: Eighteenth Workshop on Geothermal Reservoir Engineering, Stanford University, p. 17-27.

Horita, J., Cole, D.R., and Weslowski, D.J., 1994. Salt effects on stable isotope partitioning and their geochemical implications for geothermal brines, Proc. 19th Annual Workshop on Geothermal Reservoir Engineering, Stanford University, 285-290.

Horita, J., Cole, D.R., and Weslowski, D.J., 1993. The activity-composition relationship of oxygen and hydrogen isotopes in aqueous salt solutions: II. Vapor-liquid equilibration of mixed salt solutions from 50 to 100 oC and geochemical implications, Geochemica Cosmochemica Acta, 57, 4703-4711.

Horita, J., Cole, D.R., and Weslowski, D.J., 1995. The activity-composition relationship of oxygen and hydrogen isotopes in aqueous salt solutions: III. Vapor-liquid equilibration of NaCl salt solutions to 350 oC, Geochemica Cosmochemica Acta, 59, 1139-1151.

Horita, J., Cole, D.R., Weslowski, D.J., and Fortier, S.M., 1996. Salt effects on isotope partitioning and their geochemical implications, Proc. Todai International Symposium on Cosmochronology and Isotope Geoscience, 33-36.

Horita, J., Weslowski, D.J., and Cole, D.R., 1993. The activity-composition relationship of oxygen and hydrogen isotopes in aqueous salt solutions: I. Vapor-liquid equilibration of single salt solutions from 50 to 100ºC, Geochemica Cosmochemica Acta, 57, 2797-2817.

Horita, J. and Weslowski D.J., 1994. Liquid-vapor fractionation of oxygen and hydrogen isotopes of water from the freezing to the critical temperature, Geochimica Cosmochemica Acta, 58, 3425-3427.

Horne, R.N. and Rodriguez, F., 1983. Dispersion in Tracer Flow in Fractured Geothermal Systems, Geophys. Res. Lett, 10, 289.

Horne, R.N., Ramey, H.J., Jr., Shang, S., Correa, A., and Hornbrook, J. The Effects of Adsorption and Desorption on Production and Reinjection in Vapor-Dominated Geothermal Fields, Proceedings, World Geothermal Congress, Vol. 3, pp. 1973–1977, International Geothermal Association, Florence, Italy, May 1995.

Horne, R.N., Johns, R.A., Adams, M.C., Moore, J.N., and Stiger, S.G., 1987. The use of tracers to analyze the effects of reinjection into fractured geothermal reservoirs: in Proceedings, Geothermal Program Review V, Washington, D.C., April 14-15, p. 37-52.

Hulen, J.B. and Nielson, D.L. Hydrothermal Factors in Porosity Evolution and Caprock Formation at The Geysers Steam Field, California: Insight from The Geysers Coring Project, Proceedings, Twentieth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, 1995.

Hulen, J.B. and Lutz, S.J. Alteration Mineralogy and Zoning in Corehole AWI 1-2 Awibengkok Geothermal System West Java Indonesia, Geothermal Resources Council Transactions, Vol. 23, pp. 19–23, Geothermal Resources Council, 1999.

Kennedy, B.M., Janik, C., Benoit, D., and Shuster, D.L., 1999. Natural geochemical tracers for injectate fluids at Dixie Valley, Proc. 24th Workshop on Geothermal Reservoir Engineering, Stanford University, SGTP-TR-162.

Kleimeyer, J.A., Rose, P.E., and Harris, J.M., 2001. Determination of ultratrace-level fluorescent tracer concentrations in environmental samples using a combination of HPLC separation and laser-excited fluorescence multi-wavelength emission detection: application to testing of geothermal well brines: Applied Spectroscopy, 55(6), 690-700.

Li, K. and Horne, R.N., 2001. Differences Between Steam-Water and Air-Water Capillary Pressures, Proceedings, Twenty-Sixth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California.

Lutz, S.J., Moore, J.N., Adams, M.C., and Norman, D.I., 1999. Tracing fluid sources in the Coso geothermal system using fluid-inclusion gas chemistry: Twenty-Fourth Workshop on Geothermal Reservoir Engineering, Stanford University, p. 188-195.

Mella, M., Rose, P.E., McCullough, J., and Buck, C., 2006. A Tracer Test Using Ethanol as a Two-Phase Tracer and 2-Naphthalene Sulfonate at a Liquid-Phase Tracer at the Coso Geothermal Field: Geothermal Resources Council Transactions, San Diego, California.

Möller, N., 1988. The prediction of mineral solubilities in natural waters: a chemical equilibrium model for the Na-Ca-Cl-SO4-H2O system to high temperature and concentration. Geochimica Et Cosmochimica Acta 52, 821-837.

Möller, N., Christov, C., and Weare, J., 2006. Thermodynamic Models of Aluminum Silicate Mineral Solubility for Application to Enhanced Geothermal Systems. The Thirty-first Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 30-Feburary 1, 2006.

Möller, N., Christov, C., and Weare, J., 2007. Thermodynamic Model for Predicting Interactions of Geothermal Brines With Hydrothermal Aluminum Silicate Minerals. The Thirty-Second Workshop on Geothermal reservoir Engineering, Stanford University, Stanford, California. January 22-23, 2007.

Möller, N., Christov, C., and Weare, J.H., 2005. Models of subsurface rock-water processes affecting fluid flow. Thirtieth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California.

Moore, J.N., Adams, M.C., Sperry, T.L., Bloomfield, K.K., and Kunzman, R., 2000. Preliminary results of geochemical monitoring and tracer tests at the Cove Fort-Sulphurdale geothermal system, Utah: Twenty-Fifth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California.

Murphy, H.D., Tester, J.W., Grigsby, C.O., and Potter, R.M., 1981. Energy extraction from fractured geothermal reservoirs, J. Geophys. Res, 86 (B8), 7145.

Nalla, N., Shook G. M., Axelsson G., 2005. Tracer Test Analysis for Characterization of Laugland Geothermal Field: Proceedings, Thirtieth Workshop on Geothermal Reservoir Engineering, SGP-TR-176, Stanford University, Stanford, California, p. 72-79.

Nalla, N., Shook, G.M., 2005. Single-well tracer test: Geothermal Resources Council Transactions, v. 29, p. 177-181.

Nash, G. and Adams, M.C., 2001. Cost effective use of GIS for tracer test data mapping and visualization: Geothermal Resources Council, Transactions, in prep.

Nimmo, J.R., Perkins, K.S., Rose, P.E., Rousseau, J.P., Orr, B.R., Twining, B.V., and Anderson, S.R., 2002. Kilometer-scale rapid transport of naphthalene sulfonate tracer in the unsaturated zone at the Idaho National Engineering and Environmental Laboratory: Vadose Zone Journal, 1, pp. 89-101.

Norman, R. and Henfling, J. Why Well Monitoring Instruments Fail, Proceedings, Thirtieth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, 2005.

Palmer, D.A. and Bell, J.L.S., 1994. Aluminum speciation and equilibria in aqueous solution: IV. A potentiometric study of aluminum acetate complexation in acidic NaCl brines 150 oC, Geochemica Cosmochemica Acta, 58, 651-659.

Palmer, D.A. and Weslowski, D.J., 1992. Aluminum speciation and equilibria in aqueous solution: II. The solubility of gibbsite in acidic sodium chloride solutions from 30-70 oC, Geochemica Cosmochemica Acta, 56, 1065-1091.

Palmer, D.A. and Weslowski, D.J., 1993. Aluminum speciation and equilibria in aqueous solution: III. Potentiometric determination of the first hydrolysis constant of aluminum (III) in sodium chloride solutions to 125ºC, Geochemica Cosmochemica Acta, 57, 2929-2938.

Palmer, D.A., Bénézeth, P., and Wesolowski, D.J. Aqueous High-temperature Solubility Studies. I. The Solubility of Boehmite as Functions of Ionic Strength (to 5 molal, NaCl), Temperature (100 –290°C), and pH as Determined by in situ Measurements, Geochim. Cosmichim. Acta, Vol. 65, No. 13, pp. 2081–2095, 2001.

Persoff, P. and Hulen, J.B. Hydrologic Characterization of Reservoir Metagraywacke from Shallow and Deep Levels of The Geysers Vapor-dominated Geothermal System, California, USA, Geothermics, Vol. 30, pp. 169–192, 2001.

Persoff, P. and Pruess, K. Two-Phase Flow Visualization and Relative Permeability Measurement in Natural Rough-Walled Rock Fractures, Water Resour. Res., Vol. 31, No. 5, pp. 1175-1186, May 1995.

Phillips, S.L., Igbene, A., Fair, J.A., Ozbek, H., and Tavana, M. A Technical Databook for Geothermal Energy Utilization, Lawrence Berkeley National Laboratory Report LBL-12810, Berkeley, California, 46 pp., 1981.

Pruess, K. and Tsang, Y.W. On Two-Phase Relative Permeability and Capillary Pressure of Rough-Walled Rock Fractures, Water Resour. Res., Vol. 26, No. 9, pp. 1915-1926, September 1990.

Roberts, J.J., Duba, A.G., Bonner, B.P., and Kasameyer, P.W. The Effects of Capillarity on Electrical Resistivity during Boiling in Metashale from Scientific Corehole SB-15-D, The Geysers, California, USA, Geothermics, Vol. 30, Issues 2-3, pp. 235–254, April 2001.

Roberts, J.J., Bonner, B.P. ,and Duba A.G. Electrical Resistivity Measurements of Andesite and Hydrothermal Breccia from the Awibengkok Geothermal Field, Indonesia, Proceedings, Twenty-Fifth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, pp. 339-344, 2000.

Robinson, B.A. and Birdsell, S.A., 1987. Proc. Geothermal Program Review V, April 14-15, Washington, D.C. Conf-8704110 (DE88003737).

Robinson, B.A. and Tester, J.W., 1984. Dispersed fluid flow in fractured reservoirs: an analysis of tracer-determined residence time distributions, J. Geophys. Res., 89 (B12), 10374.

Robinson, B.A., Tester, J.W., and Brown, L., 1984. Reservoir sizing using inert and chemically reacting tracers, 59th Annual SPE Technical Conference and Exhibition, September 16-19, 1984, paper #13147.

Rose, M.C., Apperson, K.D., Johnson, S.D., and Adams, M.C., 1997. Numerical simulation of a tracer test at Dixie Valley, Nevada: Twenty-Second Workshop on Geothermal Reservoir Engineering, Stanford University, p. 169-176.

Rose, P.E. and Adams, M.C., 1997. The use of fluorescent compounds as reactive and conservative tracers in hydrothermal environments: Proceedings, Fifth International Symposium on Hydrothermal Reactions, Gatlinburg TN, in press.

Rose, P.E., Benoit, W.R., Apperson, K.D., and Adams, M.C., 1998. Tracer testing at Dixie Valley, Nevada, using pyrene tetrasulfonate, amino G, and fluorescein: Geothermal Resources Council, p. 583-587.

Rose, P.E., 1998. Candidate fluorescent tracers for use in hypersaline hydrothermal environments: Proc. 4th International HDR Forum, Strasbourg, September, 28-30.

Rose, P.E., 1998. The use of polyaromatic sulfonates as tracers in high temperature geothermal reservoirs: Proceedings,20th NZ Geothermal Workshop, 239-243.

Rose, P.E., 1999. Fluorescent tracers for use in engineered geothermal systems: Proceedings, Murphy Conference, Sendai, Japan.

Rose, P.E. and Adams, M.C., 1994. The application of rhodamine WT as a geothermal tracer: Geothermal Resources Council, Transactions, vol. 18, p. 237-240.

Rose, P.E., 1999. Testing of thermally stable tracers for use in high temperature geothermal reservoirs: DOE Program Review, San Francisco.

Rose, P.E., 2000. Conservative and reactive tracers for use in hot dry rock systems: Proceedings, Murphy Conference, Baden, Switzerland, March 2000.

Rose, P.E., 2000. The application of polyaromatic sulfonates as tracers in geothermal and ground water environments: Proceedings : American Association of Petroleum Geologists, New Orleans.

Rose, P.E., Adams, M.C., and Benoit, D., 1995. A tracer test at the Beowawe geothermal field, Nevada, using fluorescein and tinopal CBS: U.S. Department of Energy Geothermal Reservoir Technology Research Program, Abstracts of Selected Research Projects Rept. DOE/EE-0075, March 1995, p. 4.32-4.39.

Rose, P.E., and McPherson, P.M., 1997. New fluorescent tracers for use in geothermal reservoirs: Geothermal Resource Council Transactions, 21, 249-253.

Rose, P.E., Benoit, W.R., and Kilbourn, P.M., 2001. The application of the polyaromatic sulfonates as tracers in geothermal reservoirs: Geothermics, 30(6), pp. 617-640.

Rose, P.E., Benoit, W.R., Bacon, L., Tandia, B., Kilbourn, P.M., 2000. Testing the naphthalene sulfonates as geothermal tracers at Dixie Valley, Ohaaki, and Awibengkok: Proc. Twenty-Fifth Workshop on Geothermal Reservoir Engineering, Stanford University, SGP-TR-165, pp. 36-42.

Rose, P.E., Capuno, V., Peh, A., Kilbourn, P.M., and Kasteler, C., 2002. The Use of the Naphthalene Sulfonates as Tracers in High Temperature Geothermal Systems, Proceedings,23rd PNOC Geothermal Conference.

Rose, P.E., Faulder, D.D., and Apperson, K.D., 1997. Fluid volume and flow constraints for a hydrothermal system at Beowawe, Nevada: SPE 38762.Rose, P.E., Goranson, C., Salls, D., Kilbourn, P.M., 1999. Tracer testing at Steamboat Hills, Nevada, using fluorescein and 1,5-naphthalene disulfonate: Proc. Twenty-Fourth Workshop on Geothermal Reservoir Engineering, Stanford University, SGP-TR-162, pp. 17-23.

Rose, P.E., Johnson, S.D., and Kilbourn, P.M., 2001. Tracer testing at Dixie Valley, Nevada, using 2-naphthalene sulfonate and 2,7-naphthalene disulfonate: Proc. Twenty-Sixth Workshop on Geothermal Reservoir Engineering, Stanford University, SGP-TR-168, pp. 60-65.

Rose, P.E., Johnson, S.D., and Kilbourn, P.M., and Kasteler, C., 2002. Tracer Testing at Dixie Valley, Nevada Using 1-Naphthalene Sulfonate and 2,6-Naphthalene Disulfonate: Proc. Twenty-Seventh Workshop on Geothermal Reservoir Engineering, Stanford University, SGP-TR-171.

Rose, P.E., Mella, M., and Kasteler, C., 2003. A new tracer for use in liquid-dominated, high-temperature geothermal reservoirs: Geothermal Resources Council Transactions, 27, pp. 403-406.

Rose, P.E., Mella, M., Kasteler, C., and Johnson, S.D., 2004. The Estimation of Reservoir Pore Data from Tracer Data: Proceedings,29th Workshop on Geothermal Reservoir Engineering, Stanford University SGP-TR-175.

Rose, P.E., Johnson, S.D., Wong, Y.L., Carter, T., Kasteler, C., and Kilbourn, P., 2002. Sub Part-Per-Trillion Detection of a Fluorescent Tracer at the Dixie Valley and Beowawe Geothermal Reservoirs: Geothermal Resources Council Transactions, 26, 113-117.

Sanjuan, B., Pinault, J.L., Rose, P.E., Gerard, A., Brach, M., Braibant, G., Crouzet, C., Foucher, J.C., Gautier, A., and Touzelet, S., 2006. Tracer Testing of the Geothermal Heat Exchanger at Soultz-sous-Forets, France between 2000 and 2005, Geothermics, 35(5,6), pp. 622-653.

Satik, C. A Measurement of Steam-Water Relative Permeability, Proceedings, Twenty-Third Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, 1998.

Shinohara, K. Calculation and Use of Steam/Water Relative Permeabilities in Geothermal Reservoirs, Report SGP-TR-29, Stanford University, Stanford, California, June 1978.

Shook, G.M. and Forsmann, J.H., 2005. Tracer Interpretation Using Temporal Moments on a Spreadsheet: Idaho National Laboratory, INL/EXT-05-00400.

Shook, G.M., 1996. Prediction of Reservoir Pore Volume from Conservative Tracer Tests: Geothermal Resources Council Transactions, v. 22, p. 477-480.

Shook, G.M., 1999. Prediction of Thermal Breakthrough from Tracer Tests: Proceedings, Twenty-Fourth Workshop on Geothermal Reservoir Engineering, SGP-TR-162 Stanford University, Stanford, California, p. 24-30.

Shook, G.M., 2001. Predicting thermal breakthrough in heterogeneous media from tracer tests: Geothermics, v. 30, 573-589.

Shook, G.M., 2001. Predicting Thermal Velocities in Fractured Media from Tracer Tests: Geothermal Resources Council Transactions, v. 25, p. 465-46.

Shook, G.M., 2003. A Simple Fast Method of Estimating Fractured Reservoir Geometry from Tracer Tests: Geothermal Resources Council Transactions, v. 27, p. 407-411.

Shook, G.M., 2004. Estimating Fracture Surface Areas from Tracer Tests: Mathematical Formulation: Geothermal Resources Council Transactions, v. 28, p, 627-629.

Shook, G.M., 2005. A Systematic Method for Tracer Test Analysis: An Example Using Beowawe Tracer Data: Stanford Geothermal Program Proceedings, v. 30, p. 166-171.

Simonson, J.M and Palmer, D.A., 1995. Liquid-vapor partitioning in the system Na-H-NH4-NH3-OH-CI-H2O to 350ºC, Proceeding so the World Geothermal Congress 1995, 969-974.

Simonson, J.M and Palmer, D.A., 1997. Volatility of HCl and the thermodynamics of brines during brine dryout, Proceedings : Geothermal Program Review XV, "The Role of Research in the Changing World of Energy Supply, Springfield, VA: National Technical Information Service, 1997, 2-25 – 2-31.

Simonson, J.M. and Palmer, D.A.. Vapor-Liquid Equilibrium of Chlorides in Aqueous Systems to High Temperatures: Application to The Geysers Geothermal Field, Geothermal Resources Council Transactions, Vol. 18, pp. 347–352, Geothermal Resources Council, 1994.

Simonson, J.M. and Palmer, D.A., 1993. Liquid-vapor partitioning of HCl(aq) to 623 oK, Geochemica Cosmochemica Acta, 57, 1-7.

Simonson, J.M. and Palmer, D.A., 1994. Vapor-liquid equilibrium of chlorides in aqueous systems to high temperatures: Application to The Geysers Geothermal Field, Geothermal Resource Council Transactions, 18, 347-352.

Simonson, J.M., Palmer, D.A., and Carter, R.W. Liquid-Vapor Partitioning of NaCl(aq) from Concentrated Brines at Temperatures to 350˚C, Proceedings, Nineteenth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, 1994.

Simonson, J.M., Palmer, D.A., and Carter, R.W., 1994. Liquid-vapor partitioning of NaCl(aq) from concentrated brines at temperatures to 350ºC, roc. 19th Annual Workshop on Geothermal Reservoir Engineering, Stanford University, 245-251.

Spencer R. J., Möller, N., and Weare, J., 1990. Predictions of mineral solubilities in natural waters: a chemical equilibrium model for the Na-K-Ca-Mg-Cl-SO4-H2O system at temperatures below 25oC. Geochimica Et Cosmochimica Acta 54, 575-590.

Tester, J.W., 1985. Proc. Geothermal Program Review IV, Sep. 11-12, Washington, D.C., Conf-8509142 (DE86004074).

Tester, J.W., Bivins, R.L., and Potter, R., 1982. Interwell tracer analysis of a hydraulically fractured granitic geothermal reservoir, Soc. Pet. Eng. J., 22, 537.

Tripp, A.C., Adams, M.C., Moore, J.N., and Wright, P.M., 1990. Estimation of single injector tracer test impulse responses: Fifteenth Workshop on Geothermal Reservoir Engineering, Stanford University, p. 125-129.

Tripp, A.C. and Adams, M.C., 1991. Estimation of effective flow-path temperature using reactive tracers: University of Utah Research Institute, Earth Science Laboratory Rept., ESL-91010-JP, DOE/ID/12929-2.

Tripp, A.C., Adams, M.C., Moore, J.N. and Wright, P.M., 1989,. Estimation of tracer test impulse responses: University of Utah Research Institute, Earth Science Laboratory Rept., ESL-89031-PR, DOE/ID/12489-60.

Weare J. H., Möller N., Duan Z.H., and Christov, C., 2001. Thermodynamic models of natural fluids: Theory and practice. Abstracts of Papers of the American Chemical Society 221, U535-U536.

Weslowski, D.J. and Palmer, D.A., 1994. Aluminum speciation and equilibria in aqueous solution:

Weslowski, D.J., 1992. Aluminum speciation and equilibria in aqueous solution: I. The solubility of gibbsite in the system Na-K-Cl-OH-Al(OH)4 from 0-100ºC, Geochemica Cosmochemica Acta, 56, 1065-1092.

Weslowski, D.J., Palmer, D.A., and Begun, G.M., 1990. Complexation of aluminate anion by Bis-Tris in aqueous media at 25-50 oC, J. Soln. Chem., 19, 1590173.

Wilt M., Mallan, R., Kasameyer, P., and Kirkendall, B. Extended Logging for Geothermal Resources: Field Trials with the Geo-Bilt System, Proceedings, Twenty-Seventh Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, 2002.

Wong, Y.L. and Rose, P.E., 2000. The testing of fluorescein derivatives as candidate geothermal tracers: Geothermal Resource Council Transactions, 24, 637-640.

Wu, X., Pope, G.A., Shook, G.M., Srinivasan, S., 2005. A Method of Analyzing Tracer Data to Calculate Swept Pore Volume and Thermal Breakthrough in Fractured Geothermal Reservoirs Under Two-Phase Flow Conditions: Proceedings, Thirtieth Workshop on Geothermal Reservoir Engineering, SGP-TR-176 Stanford University, Stanford, California, p. 178-184.

Yagi, M., Yamada, Y., Yasuda, Y., Uchida, T., Adams, M., Akazawa, T., and Wada, T., 1997. Experimental study for thermal stability of tracers with a view to applying them to high-temperature geothermal fields: Japanese Geothermal Society Annual Meeting >97, Sapporo, Japan.

Enhanced Geothermal Systems

Adams, M. C., 2004. Use of Naturally-Occurring Tracers to Monitor Two-Phase Conditions in the Coso Reservoir. Twenty-Ninth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California.

Adams, M.C., J.N. Moore, et al., 2005. Fluid-mineral equilibria and injection in EGS - effect of injecting groundwater. Thirtieth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California.

Baria, R., E. Majer, M. Fehler, N. Toksoz, C. Bromley, and D.Teza, 2006. International cooperation to address induced seismicity in geothermal systems. Thirty-First Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California, January 30-February 1, 2006 SGP-TR-179.

Brown, S.T., Kennedy, B.M., DePaolo, D., and Evans, W.C., 2008. "Isotopic constraints on the chemical evolution of geothermal fluids, Long Valley, California. Geothermal Resources Council Transactions, 32, pp.269-272.

Burton, E.A., Bourcier, W., Bruton, C.J., Roberts, J.J., Carlson, S.C., 2004. Evidence for the impact of water-rock interactions on permeability in EGS. Geothermal Resources Council Transactions 2004 28, 253–257 (Annual Meeting, Palm Springs, California, August 30–September 2).

Carlson, S.C., Roberts, J.J., Detwiler, R.L., Burton, E.A., Robertson-Tait, A., Morris, C., Kasameyer, P., 2004. Fracture permeability evolution in rock from the Desert Peak EGS Site, Geothermal Resources Council Transactions 2004 28, 279–284 (Annual Meeting, Palm Springs, California, August 30–September 2).

Carlson, S.C., Roberts, J.J., Detwiler, R.L., Viani, B.E., Roberts, S.K., 2005. Fracture permeability evolution in Desert Peak quartz monzonite. Geothermal Resources Council Transactions 2005 29, 337–342 (Annual Meeting, Reno, NV, September 24–26).

Christenson, B.W., Kennedy, B.M., Adams, M.C., Bjornstad, S.C., and Buck, C., 2007. Chemical and isotopic characteristics of the Coso East Flank hydrothermal fluids: implications for the location and nature of the heat source. Proceedings, 32nd Workshop on Geothermal Reservoir Engineering, Stanford Geothermal Program Report SGP-TR-183.

Craig, H., Boato, G.,and White, D.E., 1956. "Isotopic geochemistry of thermal waters." In: Conf. on Nuclear Processes in Geological Settings, Proceedings, Second National Academy of Sciences, Natl. Res. Council Publ., v.19, p. 29-44.

Davatzes, N.C. and Hickilometersan, S., 2005. Fault rock mineralogy and fluid flow in the Coso Geothermal Field, California: American Geophysical Union (AGU) 2005 National Meeting. # T23B-0546.

Davatzes, N.C. and Hickilometersan, S., 2005a. Comparison of acoustic and electrical image logs from the Coso geothermal field, California: Proceedings, 30th Workshop on Geothermal Reservoir Engineering, Stanford University, January 31- February 2, 2005. SGP-TR-176, v. 30, 11 p.

Davatzes, N.C. and Hickilometersan, S., 2005b. Controls on fault-hosted fluid flow: Preliminary results from the Coso Geothermal Field, California: Geothermal Resources Council Transactions, v. 29, p. 343-348.

Davatzes, N.C. and Hickilometersan, S., 2006. Stress, faulting and fluid flow in the Coso Geothermal Field, California: EOS Transactions, American Geophysical Union. Vol. 87, no. 52, Suppl. 26 Dec. 2006

Davatzes, N.C. and Hickilometersan, S., 2006a. Stress and faulting in the Coso Geothermal Field: Update and recent results from the East Flank and Coso Wash: Proceedings,31st Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford California, January 30-February 1, 2006, SGP-TR-179, v. 31, 12 p.

Davatzes, N.C. and Hickilometersan, S., 2007. Stress and fault rock controls on fault zone hydrology, Coso Geothermal Field, California: AAPG.

Davatzes, N.C. and Hickilometersan, S., in prep., Mechanical and hydrologic evolution of faults zones in geothermal systems: to be submitted to Journal of Structural Geology

Davatzes, N.C. and Hickilometersan, S., in review, Stress, fracture, and fluid flow analysis using acoustic and electrical image logs in hot fractured granites of the Coso Geothermal Field, California: in Pöppelreiter, M., Garcia-Carballido, C., Kraaijveld, M., Epping, W., and Xu, C. (eds) AAPG Special Publication: Borehole and Dip Meter Technology, Structural Applications: Stress in Basement, Ch 24.

Davatzes, N.C. and Hickilometersan, S.H., 2006b. Section 3.1 Mechanical, Mineralogical, and Petrophysical Analysis of Fracture Permeability: in Rose, P., Hickilometersan, S., McCulloch, J., Davatzes, N.C., Moore, J.M., Kovac, K., Adams, M., Mella, M., Wannamaker, P., Julian, B., Foulger, G., Swenson, D., Gosavi, S., Bhat, A., Richards-Dinger, K., Monastero, F., Weidler, R., Baisch, S., Ghassemi , A., Kohl, T., and Megel, T., 2006, Progress Report for Year Ending December 31, 2005: Creation of an Enhanced Geothermal System through Hydraulic and Thermal Stimulation: Report to DOE, grant # DE-FC07-01ID14186, 239 p., p. 135-164.

Davatzes, N.C., Hickilometersan, S.H., Sheridan, J., 2006. Section 2.1 Fracture and Stress Analysis: in Rose, P., Hickilometersan, S., McCulloch, J., Davatzes, N.C., Moore, J.M., Kovac, K., Adams, M., Mella, M., Wannamaker, P., Julian, B., Foulger, G., Swenson, D., Gosavi, S., Bhat, A., Richards-Dinger, K., Monastero, F., Weidler, R., Baisch, S., Ghassemi , A., Kohl, T., and Megel, T., 2006, Progress Report for Year Ending December 31, 2005: Creation of an Enhanced Geothermal System through Hydraulic and Thermal Stimulation: Report to DOE, grant # DE-FC07-01ID14186, 239 p., p. 11-37.

DePaolo, D., 2006. “Isotopic effects in fracture-dominated reactive fluid-rock systems.” Geochimica et Cosmochimica Acta, v.70, p. 1077-1096.

Detwiler, R.L., Roberts, J., Ralph, W., Bonner, B.P., 2003. Modeling fluid flow and electrical resistivity in fractured geothermal reservoir rocks. Proc. Twenty-Eighth Workshop on Geothermal Reservoir Engineering SGP-TR-173 (Stanford, California, January 27–29; also available as LLNL Report UCRL-JC-150601).

Detwiler, R.L., Roberts, J.J., 2003. Electrical resistivity as an indicator of saturation in fractured geothermal reservoir rocks: Experimental data and modeling. In International Collaboration for Geothermal Energy in the Americas. Geothermal Resources Council Transactions 27, 359–363.

Dobson, P., Sonnenthal, E., Kennedy, B.M., van Soest, M., and Lewicki, J., 2006. Temporal changes in noble gas compositions within the Aidlin sector of The Geysers geothermal system. Transactions Geothermal Res. Council, 2006 Annual Meeting, San Diego, California., v. 30, pp 903-908.

Dobson, P., Sonnenthal, E., Lewicki, J., and Kennedy, B.M., 2006. Evaluation of C-14 as a natural tracer for injected fluids at the Aidlin sector of The Geysers geothermal system through modeling of mineral-water-gas reactions. Proc., TOUGH Symposium 2006, LBNL, Berkeley, California, May 15-17, 2006.

Elkibbi, M. and J.A. Rial. “Shear-wave splitting: an efficient tool to detect 3D fracture patterns at The Geysers, California.” Proceedings, Geothermal Reservoir Engineering, Stanford, 28, 143-149 (2003).

Elkibbi, M., M. Yang, and J.A. Rial. “Imaging crack systems in The Geysers with shear-wave splitting.” Geothermal Resources Council Transactions, 28, 789-800 (2004).

Elkibbi, Maya, 2004. Characterization of fracture-induced anisotropy using shear-wave splitting in the Geysers reservoir, California. Doctoral dissertation, University of North Carolina Chapel Hill, NC.

Foulger, G.R. and L. De Luca, Detailed image of fractures activated by a fluid injection in a producing Indonesian geothermal field, Proceedings, Thirty-Fourth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, February 9-11, SGP-TR-187, 2009.

Foulger, G.R., and Julian, B.R., 2004. A powerful tool: Use of time-dependent MEQ tomography for monitoring producing geothermal reservoirs: Geotherm. Res. Council Bull., v. 33, p. 120-126. www.dur.ac.uk/g.r.foulger/Offprints/Geothermal Resources CouncilTom2004.pdf.

Foulger, G.R., B.R. Julian, B.R.. and F. Monastero, Seismic monitoring of EGS tests at the Coso Geothermal area, California, using accurate MEQ locations and full moment tensors, Proceedings, Thirty-Third Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 28-30, SGP-TR-185, 261-268, 2008.

Ghassemi, A. and Tarasovs, S., 2006. Fracture slip and opening in response to water injection. Geothermal Resources Council Transactions.

Goff, F., H.A. Wollenberg, D.C. Brookins, and R.W. Kistler, 1991. “A Sr-isotopic comparison between thermal waters, rocks, and hydrothermal calcites, Long Valley caldera, California.” J. Volc. Geotherm. Res., v.48, p. 265-281.

Johnson, T.M. and D.J. DePaolo, 1996. “Reaction-transport models for radiocarbon in groundwater: The effects of dispersive transport and the use of Sr isotope ratios to correct for water-rock interaction.” Water Resources Res., v. 32, p. 2203-2212.

Johnson, T.M. and DePaolo, D.J., 1994. “Interpretation of isotopic data in groundwater–rock systems: model development and application to Sr isotopic data from Yucca Mountain.” Water Resources Res., v.30, p. 1571–1587.

Julian, B.R. and Foulger, G.R., 2009. Time-Dependent Seismic Tomography of Geothermal Systems, Proceedings, Thirty-Fourth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, February 9-11, SGP-TR-187.

Julian, B.R., and Foulger, G.R., 2004. Microearthquake Focal Mechanisms: A Tool for Monitoring Geothermal Systems: Geotherm. Res. Council Bull., v. 33, p. 166-171. www.dur.ac.uk/g.r.foulger/Offprints/Geothermal Resources CouncilFM2004.pdf

Julian, B.R. and Foulger, G.R., 2005. Time-dependent seismic tomography of the Coso geothermal area, 1996-2004, in Geothermal Resources Council Annual Meeting, Reno, Nevada, Geothermal Resources Council.

Julian, B.R., Foulger, G.R., and Richards-Dinger, K., 2004. Monitoring microearthquake activity and structure changes at the Coso geothermal area, in AGU Western National Meeting, San Francisco, California, American Geophysical Union.

Julian, B.R., Foulger, G.R., and Richards-Dinger, K., 2004. The Coso Geothermal Area: A Laboratory for Advanced MEQ Studies for Geothermal Monitoring, in Geothermal Resources Council Annual Meeting, Indian Springs, California. (www.dur.ac.uk/g.r.foulger/Offprints/PalmSprings.pdf)

Julian, B.R., Foulger, G.R., and Richards-Dinger, K., 2005. Monitoring microearthquake activity and structure changes at the Coso geothermal area, in 30th Stanford Workshop on Geothermal Reservoir Engineering, Stanford, California, Stanford University.

Julian, B.R., Foulger, G.R., Monastero, F.C., and Richards-Dinger, K., 2003. Four-dimensional tomography reveals changes in structure 1996 - 2002 at the Coso geothermal area, California: EOS Fall Meeting Supplement, p. Abstract S52I-01.

Julian, B.R., Foulger, G.R., Richards-Dinger, K., and Monastero, F., 2005. Time-Dependent Tomography and Microearthquake Moment Tensors in the Coso Geothermal Area, in AGU Western National Meeting, San Francisco, California.

Julian, B.R., Foulger, G.R., Richards-Dinger, K., and Monastero, Francis, 2006. Time-dependent seismic tomography of the Coso geothermal area, 1996-2004, in 31st Stanford Workshop on Geothermal Reservoir Engineering, Stanford, California, Stanford University, 30 January -1 February 2006. (http://geothermal.stanford.edu/pdf/SGW/2006/julian.pdf)

Majer, E. L., Baria, R, 2006. Cooperative Research on Induced Seismicity In EGS, Geothermal Resources Council Transactions, Vol 30, 145-148.

Majer, E. L., Baria, R. Cooperative Research on Induced Seismicity Associated with Enhanced Geothermal Systems. Geothermal Resources Council Transactions Vol 29. 108-111.

Majer, E. L., Peterson, J. E., and Stark M. A., 2003. Integrated High Resolution Microearthquake Analysis and Monitoring for Optimizing Steam Production at The Geysers Geothermal Field, California, Final report to the California Energy Commission, California Energy Commission Geothermal Resources Development Account Grant Agreement GEO-00-003. 40 pp.

Majer, E., Baria, R. and Stark, M., 2008. Protocol for induced seismicity associated with enhanced geothermal systems. Report produced in Task D Annex I (9 April 2008), International Energy Agency-Geothermal Implementing Agreement (incorporating comments by: C. Bromley, W. Cumming, A. Jelacic and L. Rybach).

Majer, E.L., Baria, R., Stark, M., Oates, S., Bommer, J., Smith, B., and Asanuma, H., 2007. Induced seismicity associated with Enhanced Geothermal Systems, Geothermics 36, 185-227. LBNL- 61681

Maris, V.,P. Wannamaker and Y. Sasaki, Three-dimensional inversion of magnetotelluric data over the Coso geothermal field, using a PC: Geothermal Resources Council Transactions, 31, 6 pp., 2007.

Maris, V., P. Wannamaker and Y. Sasaki, Three-dimensional inversion of magnetotelluric data on a PC; methodology and applications to the Coso geothermal field: Geothermal Resources Council Transactions, 30, 6 pp., 2006.

Mella, M., Rose, P.E., Kovac, K., Xu, T., Pruess, K., and McCullough, J., (2006) Calcite Dissolution in Geothermal Reservoirs Using Chelants: Geothermal Resources Council Transactions, San Diego, California.

Mella, M., Rose, P.E., McCullough, J., and Cliff Buck (2006) A Tracer Test Using Ethanol as a Two-Phase Tracer and 2-Naphthalene Sulfonate at a Liquid-Phase Tracer at the Coso Geothermal Field: Geothermal Resources Council Transactions, San Diego, California.

Newman, G., M. Hoversten, P. Wannamaker, and E. Gasparikova, 3D Magnetotelluric Characterization of the Coso Geothermal Field: Geothermics, in revision, 2007.

Newman, G., M. Hoversten, P. Wannamaker, and E. Gasparikova, 3D Magnetotelluric Characterization of the Coso Geothermal Field: Proc. Stanford Geothermal Symp., 5 pp., 2005.

Roberts, J; Bonner, BP; Duba, A. 1999. Electrical resistivity measurements of brine saturated porous media near reservoir conditions: Awibengkok preliminary results. Geothermal Resources Council Transactions 1999 23, 35–39 (Annual Meeting, Reno, NV, October 17–20; also available as LLNL Report UCRL-JC-134711).

Roberts, J., Detwiler, R., Ralph, W., Bonner, B.P., 2002. Fracture surface area effects on fluid extraction and the electrical resistivity of geothermal reservoir rocks. Geothermal Resources Council Transactions 2002 26, 411–417 (Annual Meeting, Reno, NV, September 22–25; also available as LLNL Report UCRL-JC-148240).

Roberts, J.J., 2002. Electrical properties of microporous rock as a function of saturation and temperature. J. Appl. Phys. 91, 1687–1694.

Roberts, J.J., Duba, A.G., Bonner, B.P., Kasameyer, P.W., 2001. “The effects of capillarity on electrical resistivity during boiling in metashale from scientific corehole SB-15-D, The Geysers, California, USA. Geothermics 30, 235–254.

Roberts, J.J., Ramirez, A., Carlson, S., Ralph, W., Bonner, B.P., Daily W., 2001. Laboratory and Field Measurements of Electrical Resistivity to Determine Saturation and Detect Fractures in a Heated Rock Mass. Lawrence Livermore National Laboratory, Livermore, California, UCRL-JC-143220.

Rose, P.E., Barton, C., McCulloch, J., Moore, J.M., Kovac, K., Sheridan, J., Spielman, P., and Berard, B. (2003) The Coso EGS Project—Recent Developments: Geothermal Resources Council Transactions, 27, pp. 879-883.

Rose, P.E., Barton, C., Petty, S., McCulloch, J., Moore, J.M., Kovac, K., Sheridan, J., Spielman, P., and Berard, B. 2002. Creation of an Enhanced Geothermal System through Hydraulic and Thermal Stimulation: Geothermal Resources Council Transactions, 26, pp. 245-250.

Rose, P.E., Barton, C., Petty, S., McCulloch, J., Moore, J.M., Kovac, K., Sheridan, J., Spielman, P., and Berard, B. 2002. Creation of an Enhanced Geothermal System through Hydraulic and Thermal Stimulation: Geothermal Resources Council Transactions, 26, pp. 245-250.

Rose, P.E., McCulloch, J., Adams, M.C., and Mella, M. 2005. An EGS Stimulation Experiment under Low-Wellhead Conditions: Proceedings, 30th Workshop on Geothermal Reservoir Engineering, Stanford University SGP-TR-176.

Rose, P.E., Mella, M., and McCulloch, J., 2006. A Comparison of Hydraulic Stimulation Experiments at the Soultz, France and Coso, California Engineered Geothermal Systems: Proceedings, 31st Workshop on Geothermal Reservoir Engineering, Stanford University SGP-TR-179.

Rose, P.E., Sheridan, J., McCulloch, J., Moore, J.M., Kovac, K., Weidler, R., and Hickilometersan, S., 2005. The Coso EGS Project—Recent Developments: Geothermal Resources Council Transactions, Reno, Nevada.

Rose, P.E., Sheridan, J., McCulloch, J., Moore, J.M., Kovac, K., Weidler, R., and Hickilometersan, S., 2005. The Coso EGS Project—Recent Developments: Proceedings, World Geothermal Congress, Antalya, Turkey.

Rose, P.E., Sheridan, J., McCulloch, J., Moore, J.M., Kovac, K., Spielman, P., and Weidler, R, Hickilometersan, S., 2004. The Coso EGS Project—Recent Developments: Geothermal Resources Council Transactions, 27, pp. 227-231.

Rose, P.E., Xu, T., Kovac, K., Mella, M., and Pruess, K., 2007. Chemical Stimulation in Near-Wellbore Geothermal Formations: Silica Dissolution in the Presence of Calcite at High Temperature and High pH, Proceedings, 32nd Workshop on Geothermal Reservoir Engineering, Stanford University SGP-TR-183.

Sheridan, J., Kovac, K., Rose, P.E., Barton, C., McCulloch, J., Berard, B., Moore, J.M., Petty, S., and Spielman, P., 2003. In situ stress, fracture and fluid flow analysis—East Flank of the Coso Geothermal Field: Proc. Twenty-Eighth Workshop on Geothermal Reservoir Engineering, Stanford University, SGP-TR-173.

Shook, G. M. and Faulder, D. D., 1991. Analysis of reinjection strategies for The Geysers: Proceedings, Sixteenth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 23-25, 1991, SGP-TR-134.

Sorey, M.L, G.A. Suemnicht, N.J. Sturchio, and G.A. Nordquist, 1991. “New Evidence on the Hydrothermal System in Long Valley caldera, California, from Wells, Fluid Sampling, Electrical Geophysics, and Age Determinations of Hot Spring Deposits.” J. Volc. Geotherm. Res., v.48, p. 229-263.

Tang, C., 2009. Detecting and modeling subsurface fracture systems in geothermal fields using shear-wave splitting, Doctoral dissertation. University of North Carolina, Chapel Hill, NC.

Tang, C., Rial, J.A., and Lees, J.M., 2009. Modeling Subsurface Cracks in the Hengill Geothermal Field, Iceland Using Shear-wave Splitting and Waveform Simulation. Submitted to J. Volcanol. Geothermal Res.

Tang, C., Rial, J.A., and Lees, J.M., 2005. Shear-wave splitting: A diagnostic tool to monitor fluid pressure in geothermal fields. Geophys. Res. Lett., 32, L21317, doi:10.1029/2005GL023551.

Tang, C., Rial, J.A., and Lees, J.M., 2008. Seismic Imaging of the Geothermal Field at Krafla, Iceland Using Shear-wave Splitting. J. Volcanol. Geothermal Res., 176(2), 315-324, doi:10.1016/j.jvolgeores.2008.04.017.

Tang, C., Rial, J.A., Lees, J.M., and Elkibbi, M., 2006. Shear-wave splitting observations and measurements at the Geothermal Field at Hengill, Iceland. Proc. Geothermal Reservoir Engineering, Stanford, 31, 512-517.

Tang, C., Zhao, Y., Rial, J.A., and Lees, J.M., 2009. Automatic, real-time detection of subsurface cracks in geothermal fields using shear-wave splitting. Submitted to Geophysical Journal International.

Truesdell, A.H. and Shook, G.M., 1997. Effects of injection into the high-temperature reservoir of the NW Geysers - a cautionary tale: Proceedings, Twenty-Second Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 27-29, 1997, SGP-TR-155.

Viani, B.E., Roberts, J.J., Detwiler, R.L., Roberts, S.K., Carlson, S.R., 2005. Simulating injectate/rock chemical interaction in fractured Desert Peak quartz monzonite. In Geothermal Energy—The World’s Buried Treasure. Geothermal Resources Council Transactions 29, 425–430.

Wannamaker, P., P. Rose, W. Doerner, B. Berard, J. McCulloch, and K. Nurse, Magnetotelluric Surveying and Monitoring at the Coso Geothermal Area, California, in Support of the Enhanced Geothermal Systems Concept: Survey Parameters, Initial Results: Proc. Stanford Geothermal Symp., 8 pp., 2004.

Wannamaker, P., P. Rose, W. Doerner, J. McCulloch, and K. Nurse, Magnetotelluric Surveying and Monitoring at the Coso Geothermal Area, California, in Support of the Enhanced Geothermal Systems Concept: Survey Parameters, Initial Results: Proc. World Geothermal Congress, Antalya, Turkey, 7 pp., 2005.

Yang, M., 2006. Imaging of Subsurface Fractures with Shear Wave Splitting, Doctoral dissertation, University of North Carolina Chapel Hill, NC.

Yang, M., 2003. Inversion of shear-wave splitting data in geothermal reservoirs, Master’s thesis. University of North Carolina, Chapel Hill, NC.

Yang, M., M. Elkibbi, and J.A. Rial, 2003. “Modeling of 3D crack attributes and crack densities in geothermal reservoirs.” Proceedings, Geothermal Reservoir Engineering, Stanford, 28, 321-327.

Zhao, Y., 2008. A new approach for the automatic detection of shear-wave splitting. Master’s thesis. University of North Carolina, Chapel Hill, NC.

Numbered References

1. The U.S. Department of Energy Geothermal Technologies Program has had many names over the years. For simplicity's sake, it will be referred to as "DOE" or the "Program" in this historical survey of geothermal research and development.
2. GGA Overview Map of Geysers. Web. www.thegga.org/overviewmap.html
3. M.A. Stark et al. The Santa Rosa-Geysers Recharge Project, Geysers Geothermal Field, California. Geothermal Resources Council Transacions 29, 145-150 (2005).
4. E.L. Majer and T.V. McEvilly. "Seismogical investigations at The Geysers geothermal field" Geophysics, 44, 246–269 (1979).
5. D.H. Oppenheimer. "Extensional tectonics at The Geysers geothermal area, California." Journal of Geophysical Research, 91, 11463–11476 (1986).
6. M.A. Stark. "Microearthquakes—a tool to track injected water in The Geysers reservoir." Geothermal Research Council, Special Report, pp. 111–117 (1992).
7. M. Stark. "Seismic evidence for a long-lived enhanced geothermal system (EGS) in the Northern Geysers Reservoir." Geothermal Resources Council Transactions, 24, 24–27 (2003).
8. A.E. Romero et al. "Characterization of the geothermal system beneath the Northwest Geysers steam field, California, from seismicity and velocity patterns." Geothermics, 23, 111-126 (1995).
9. A. Ross, G.R. Foulger, and B.R. Julian. "Non-double couple earthquake mechanisms at The Geysers geothermal area, California." Geophysical Research Letters, 23, 877-880 (1996).
10. A. Ross, G.R. Foulger, and B.R. Julian. "Source processes of industrially-induced earthquakes at The Geysers geothermal area, California." Geophysics, 64, 1877-1889 (1999).
11. G.R. Foulger et al. "Industrially induced changes in Earth structure at The Geysers geothermal area, California." Geophysical Research Letters, 24, 135-137 (1997).
12. A. Kirkpatrick et al. "Characteristics of microseismicity in the DV11 injection area, Southeast Geysers, California." Proceedings of the 24th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, USA, pp. 236-242 (1999).
13. J.L.B. Smith, J.J. Beall, and M.A. Stark. "Induced seismicity in the SE Geysers field." Geothermal Resources Council Transactions, 24, 24–27 (2000).
14. D. Eberhart-Phillips and D.H. Oppenheimer. "Induced seismicity in The Geysers geothermal area, California." Journal of Geophysical Research, 89, 1191–1207 (1984).
15. S.L. Enedy et al. "Reservoir response to injection in the Southeast Geysers." Geothermal Research Council Special Report 17, pp. 211–219 (1992).
16. E.L. Majer et al. "Induced seismicity associated with Enhanced Geothermal Systems, Geothermics, 36, 185-227. LBNL-61681 (2007).
17. Bill Smith, personal communication, June 2006.
18. R. Greensfelder. "Induced Seismicity Study – Geysers Recharge Alternative – Santa Rosa Subregional Long-Term Wastewater Project," vol. VI, Section F-2 of the Environmental Impact Report prepared for the city of Santa Rosa and the U.S. Army Corps of Engineers by Greensfelder & Associates and Parsons Engineering Science Inc. for Harland Bartholomew and Associates Inc., 100+ pp. (1996).
19. J.B. Hulen, editor. Special issue: The Geysers Coring Project and The Geysers/Clear Lake igneous-geothermal regime, Geothermics, Vol. 30, No. 2/3 pp. 165-394 (2001).
20. . P.A. Witherspoon et al. "Mexican-American Cooperative Program at the Cerro Prieto Geothermal Field." Lawrence Berkeley Laboratory Report LBL-7095, Berkeley, California, 33 pp (1978).
21. E. Giannini, A. Lazzarotto, and R. Signorini. "Lineamenti di stratigrafia e di tettonica.." La Toscana Meridionale. Rend. Soc. Ital. Min. e Petrol. 27, 33-68 (1971).

22. G. Cappetti et al. "A New Deep Exploration Program and Preliminary Results of a 3D Seismic Survey in the Larderello-Travale Geothermal Field (Italy)." Proceedings of the 2005 World Geothermal Congress, April, Antalya, Turkey, paper 759, 8 pp (2005).

23. A. Minnasale. "The Larderello Geothermal Field: a review." Earth Science Reviews, Vol. 31, Issue 2. 133-151, 10 September (1990).

24. P. Muffler and R. Cataldi, R. "Methods for regional assessment of geothermal resources," USGS-OFR-77-870, 77p (1977).

25. D. Benoit, S. Johnson, and M. Kumataka. "Development of an Injection Augmentation Program at the Dixie Valley, Nevada Geothermal Field." Proceedings World Geothermal Congress 2000, pp. 819-824 (2000).

26. D.D. Blackwell et al. "Why Basin and Range Systems Are Hard To Find II: Structural Model of the Producing Geothermal System in Dixie Valley, Nevada. Geothermal Resources Council Transactions 33, in press (2009).

27. Lawrence Berkeley Laboratory. Proceedings of the Invitational Well-Testing Symposium, October 19-21, Berkeley, California, Lawrence Berkeley Laboratory Report LBL-7027, 194 pp (1977).

28. Lawrence Berkeley Laboratory. Proceedings of the Second Invitational Well-Testing Symposium, October 25-27, Berkeley, California, Lawrence Berkeley Laboratory Report LBL-8883, 141 pp (1978).

29. Lawrence Berkeley Laboratory. Proceedings of the Third Invitational Well-Testing Symposium, March 26-28, Berkeley, California, Lawrence Berkeley Laboratory Report LBL-8883, 170 pp (1980).

30. M.G. Bonvarsson and S.M. Benson. "Well Test Data from Geothermal Reservoirs." Berkeley, Lawrence Berkeley Laboratory, LBL-13295 (1982).

31. T.N. Narasimhan and P.A. Witherspoon. "Reservoir Evaluation Tests on RRGE1 and RRGE2, Raft River Geothermal Project, Idaho." Lawrence Berkeley Laboratory, LBL-5958 (1977).

32. S.M. Benson and C.H. Lai. "A new method for evaluating composite reservoir systems," Transactions of the Geothermal Resources Council Meeting, vol. 9, pp. 487-492 (1985).

33. G.S. Bodvarsson and S.M. Benson. "A Summary of Well Testing at Lawrence Berkeley Laboratory, 1975-1982." Geothermal Resources Council Transactions, 7, 397-402 (1983).

34. D.J. Entingh. "Geothermal Well Stimulation Experiments In The United States." Proceedings World Geothermal Congress 2000, Kyushu - Tohoku, Japan, pp. 3689-3694 (2000).

35. The name "hot dry rock" and the abbreviation "HDR" originated with the Los Alamos team in 1971. The first known use of the term in written material was by Bob Potter, in a paper he presented at a Geothermal Research Conference sponsored by the National Science Foundation and held at the Battelle Seattle Research Center (Seattle, Washington) in September of 1972. The title of the invited (but never formally published) paper was "Geothermal Resources Created by Hydraulic Fracturing in Hot Dry Rock."

36. M.C. Smith. "The furnace in the basement, Part 1: The early days of the hot dry rock geothermal energy program, 1970–1973," Los Alamos National Laboratory report LA-12809, Pt. 1, Los Alamos, New Mexico (1995).

37. Mort Smith, a metallurgist and a group leader in the CMF Division at Los Alamos, was the leader of the nascent HDR Program during the years covered in this section.

38. E.S. Robinson et al. "A preliminary study of the nuclear Subterrene," (Smith, M. C., ed.), Los Alamos Scientific Laboratory report LA-4547, Los Alamos, New Mexico (1971).

39. R.M. Potter, E.S. Robinson, and M.C. Smith. "Method of extracting heat from dry geothermal reservoirs," U.S. patent No. 3,786,858 (1974).

40. J.H. Sass and A.H. Lachenbruch. "Heat flow and conduction-dominated thermal regimes," in Assessment of Geothermal Resources of the United States— 1978 (Muffler, L.J.P., Ed.), USGS Circular 790, Arlington, Virginia (1979).

41. The Hot Dry Rock team at Los Alamos National Laboratory was composed of Mort Smith, Bob Potter, and Don Brown.

42. R.L. Smith, R. A. Bailey, and C.S. Ross. "Geologic Map of the Jemez Mountains, New Mexico," U. S. Geological Survey Miscellaneous Investigations Series Map No. I-571, Reston, Virginia (1970).

43. D.B. Slemmons. "Fault activity and seismicity near the Los Alamos Scientific Laboratory Geothermal Test Site, Jemez Mountains, New Mexico," Los Alamos Scientific Laboratory report LA-59-11-MS, Los Alamos, New Mexico (1975).

44. R.A. Pettitt. "Testing, planning, and redrilling of Geothermal Test Hole GT-2, phases IV and V," Los Alamos Scientific Laboratory report LA-7586-PR, Los Alamos, New Mexico (1978).

45. G.A. Zyvoloski, R.L. Aamodt, and R.G. Aguilar. "Evaluation of the second hot dry rock geothermal energy reservoir: results of Phase I, Run Segment 5," Los Alamos National Laboratory report LA-8940-HDR, Los Alamos, New Mexico (1981).

46. Hot Dry Rock Geothermal Energy Development Program. "Annual report, fiscal year 1978" (Brown, M.C., Smith, M.C., Siciliano, C.L.B., and Duffield, R.B., eds.), Los Alamos Scientific Laboratory report LA-7807-HDR, Los Alamos, New Mexico (1979).

47. P.M. Roberts, K. Aki, and M.C. Fehler. "A low-velocity zone in the basement beneath the Valles Caldera, New Mexico," J. Geophys. Res. 96:21583–21596 (1991).

48. L.K. Steck et al. "Crust and upper mantle structure beneath Valles Caldera, New Mexico: Results from the JTEX Teleseismic Experiment," J. Geophys. Res. 103:24301–24320 (1998).

49. J.C. Rowley and R.S. Carden. "Drilling of hot dry rock geothermal Energy Extraction Well EE-3," Los Alamos National Laboratory report LA-9512-HDR, Los Alamos, New Mexico (1982).

50. HDR Project data archives.

51. D.S. Dreesen and R.W. Nicholson. "Well completion and operations for MHF of Fenton Hill HDR Well EE-2," Geothermal Resource Council annual meeting and international symposium on geothermal energy (August 26–30, 1985: Kailua Kona, HI). Geothermal Resources Council Transactions, vol. 9, Part II, pp. 89–94 (1985).

52. Scott Phillips, EES Division, Los Alamos National Laboratory (2008).

53. Z.V. Dash et al. "ICFT: An initial closed-loop flow test of the Fenton Hill Phase II HDR reservoir," Los Alamos National Laboratory report LA-11498-HDR, Los Alamos, New Mexico (1989).

54. D.W. Brown. "Recent progress in HDR reservoir engineering," in The Geothermal Partnership—Industry, Utilities, and Government Meeting the Challenges of the 90's, Proceedings of Geothermal Energy Program Review IX (March 19–21, 1991: San Francisco, California). U.S. Department of Energy document CONF-9103105, pp. 153–157 (1991).

55. D.W. Brown. "The U.S. hot dry rock program—20 years of experience in reservoir testing," in Worldwide Utilization of Geothermal Energy: An Indigenous, Environmentally Benign Renewable Energy Resource, Proceedings of the World Geothermal Congress (May 18–31, 1995: Florence, Italy), International Geothermal Association, Inc., Auckland, New Zealand, vol. 4, pp. 2607–2611 (1995).

56. Following Experiment 2077, the Phase II reservoir would remain shut in for 12 months (until December 1991, when the surface plant was essentially complete). During this time, the small (about 2.6 gpm) "backside" reservoir vent at EE-3A would cause the shut-in reservoir pressure to slowly decay—from about 2,500 psi to 2,270 psi by the beginning of Experiment 2078A (2 December 1991).

57. Hot Dry Rock Geothermal Energy Development Program. "Hot dry rock energy: Progress report, fiscal year 1992" (Winchester, W. W., ed.), Los Alamos National Laboratory report LA-UR-93-1678, Los Alamos, New Mexico (1993).

58. Hot Dry Rock Geothermal Energy Development Program. "Hot dry rock energy: Progress report, fiscal year 1993" (Salazar, J., and Brown, M., eds.) Los Alamos National Laboratory report LA-12903-PR, Los Alamos, New Mexico (1995).

59. D.V. Duchane. "Heat mining to extract hot dry rock (HDR) geothermal energy: technology transfer activities," Federal Geothermal Research Program Update, Fiscal Year 1994, U.S. Department of Energy, Washington, D.C., pp. 4.197–4.203 (1995).

60. D.V. Duchane. "Heat mining to extract hot dry rock geothermal energy: technical and scientific progress," Federal Geothermal Research Program Update, Fiscal Year 1995, U.S. Department of Energy, Washington, D.C., pp. 4.215–4.230 (1996).

61. D.W. Brown. "Experimental verification of the load-following potential of a hot dry rock geothermal reservoir," in Proceedings 21st workshop on geothermal reservoir engineering (January 22–24, 1996: Stanford, California), SGP-TR-151, pp. 281–285 (1996).

62. D.W. Brown. "Storage capacity in hot dry rock reservoirs," U.S. Patent No. 5,585,362, dated November 11, 1997 (1997).

63. During flow testing of the Phase II reservoir, it took only about two minutes to nearly double the reservoir's power production, by simply opening the motor-driven throttling valve on the production well. Making use of this HDR load-following capability would reduce the local electric utility's need to draw on its natural-gas-fired "spinning reserve" during times of peak demand (a very costly—but also very common—method of load-following, particularly during the summer air-conditioning season).

64. O. Strongin. "Identification of Geopressured Occurences Outside of the Gulf Coast, Phase II," Final Report, Science Application, Inc., McLean, VA. 22102, Prepared for DOE, Nevada Operations Office, Las Vegas, NV 89114, Under Contract No. DE-AC08-80NV10133 (1981).

65. R.H. Wallace et al. "Assessment of Geopressured Resources in the Northern Gulf of Mexico Basin," Assessment of Geopressured Resources of the United States, L. J. P. Muffler, ed., U.S. Geological Survey Circular 790 (1978).

66. Southwest Research Institute, "Geopressured Energy Availability," Electric Power Research Institute, EPRI AP-1457, Project 1272-1, July (1980).

67. C.J. John, G. Maciasz, and B.J. Harder. "Gulf Coast Geopressured-Geothermal Program Summary Report Compilation," Volumes 1- 4, U.S. Department of Energy Report, June (1998).

68. R.D. Ocamb. "Growth Faults of South Louisiana: Gulf Coast," Association of Geological Societies Transactions, v.11, p. 139-175 (1961).

69. D.G. Bebout. "Regional and local geologic setting of the Technadril-Fenix and Scisson Department of Energy Gladys McCall #1 well site," Geopressured-Geothermal Energy Resource Appraisal. R. H. Wallace, Jr. ed. (1982).

70. C.E. Hottman. "Method for producing a source of energy from an overpressured formation," U.S. Patent 3,258,069 (1966).

71. M.H. Dorfman. "Geopressured-geothermal energy and associated natural gas," Proceedings, Geothermal Energy Symposium, 11th Annual Energy-Source Technology Conference and Exhibit, New Orleans, Louisiana, American Society of Mechanical Engineers, Geothermal Resources Council, p. 97-101 (1988).

72. R.H. Wallace, Jr., editor. "Geopressured-Geothermal Energy Resource Appraisal," Louisiana Geological Survey Guidebook Series No. 2, p. 112 (1982).

73. Negus-de Wys. "The geopressured-geothermal resource, research and use," Proceedings, The National Energy Strategy – The Role of Geothermal Technology Development, San Francisco, California, 18-20 April, 1990. OSTI Identifier: OSTI6886699 (1990).

74. C.J. John. "Geology of the Gladys McCall geopressured-geothermal prospect, Cameron Parish, Louisiana," Journal of Energy Resources Technology, v. 110, p. 255-261 (1988).

75. Eaton Operating Company, Inc. Final Report (1990).

76. M.M. Plum et al. "Economic review of the geopressured-geothermal resource with recommendations," U.S. Department of Energy Technical Report, EGG-2581, OSTI 5231635, p. 20 (1989).

77. J. Griggs. "A Re-evaluation of Geopressured-Geothermal Aquifers as an Energy Source," Louisiana State University, Department of Petroleum Engineering, Masters Thesis, Baton Rouge, LA, p. 82 (2004).

78. M.A. Taylor. "The State of Geothermal Technology: Part I: Subsurface Technology," Geothermal Energy Association, November (2007).

79. G.M. Shook. "Validation of a Geothermal Simulator." EGG-EP-9851, 12 October (1991).

80. M.J. O'Sullivan, K. Pruess, and M.J. Lippmann. "Geothermal Reservoir Simulation: The State-Of-Practice and Emerging Trends," Lawrence Berkeley National Laboratory Report LBNL-44699 (2000).

81. D.H. Brownell, Jr., S.K. Garg, and J.W. Pritchett. "Governing Equations for Geothermal Reservoirs." Water Resources Research, 13 (6), December (1977).

82. S.K. Garg and D.R. Kassoy. "Convective Heat and Mass Transfer in Hydrothermal Systems, Chapter 2 in Geothermal Systems:Principles and Case Histories (Eds. L. Rybach and L.J P. Muffler), John Wiley, London, pp. 37-76 (1981).

83. S.K. Garg and J.W. Pritchett. "On Pressure Work, Viscous Dissipation and the Energy Balance Relation for Geothermal Reservoirs." Advances in Water Resources, Vol. 1, pp. 41-47 (1977).

84. G.S. Bodvarsson et al. "The Krafla Geothermal Field, Iceland, I: Analysis of Well Tests Data," Water Resources Research, 20 (11), 1515-1530 (1984).

85. G.S. Bodvarsson et al. "The Krafla Geothermal Field, Iceland, 2: The Natural State of the System," Water Resources Research, 20 (11), 1531-1544 (1984).

86. K. Pruess et al. "The Krafla Geothermal Field, Iceland, 4: History Match and Prediction of Individual Well Performance," Water Resources Research, Vol. 20, No. 11, pp. 1561 – 1584 (1984).

87. G.S. Bodvarsson et al. "The Krafla Geothermal Field, Iceland, 3: The Generating Capacity of the Field," Water Resources Research, 20 (11), 1545-1559 (1984).

88. J.H. Weare. "Models of Mineral Solubility in Concentrated Brines with Application to Field Observations," Reviews in Mineralogy, Vol. 17, pp. 143 – 176 (1987).

89. Z. Duan, N. Möller, and J. Weare. "Equation of State for the NaCl-H2O-CO2 System: Prediction of Phase Equlibria and Volumetric Properties," Geochimica et Cosmochimica Acta, Vol. 59, pp. 2869–2882 (1995).

90. Z. Duan, N. Möller, and J. Weare. "A General Equation of State for Supercritical Fluid Mixtures and Molecular Dynamics Simulations for Mixture PVTX Properties," Geochimica et Cosmochimica Acta, Vol. 60, pp. 1209–1216 (1996).

91. N. Möller, J.P. Greenberg, and J.H. Weare. "Computer Modeling for Geothermal Systems: Predicting Carbonate and Silica Scale Formation, CO2 Breakout and H2S Exchange," Transport in Porous Media, Vol. 33, pp. 173 – 204 (1998).

92. K. Pruess and T.N. Narasimhan. "A Practical Method for Modeling Fluid and Heat Flow in Fractured Porous Media," Society of Petroleum Engineers Journal, 25 (1), 14-26 (February 1985).

93. J.W. Pritchett. "Dry-Steam Wellhead Discharges From Liquid-Dominated Geothermal Reservoirs: A Result of Coupled Nonequilibrium Multiphase Fluid and Heat Flow Through Fractured Rock," B. Faybishenko, P.A. Witherspoon and J. Gale (eds.), Dynamics of Fluids and Transport in Fractured Rock, Geophysical Monograph 162, pp. 175–181, American Geophysical Union, Washington, D.C. (2005).

94. A.C. Battistelli and K. Pruess. "The Simulator TOUGH2/EWASG for Modeling Geothermal Reservoirs with Brines and Non-Condensible Gas," Geothermics, Vol. 26, No. 4, pp. 437-464 (1997).

95. K. Pruess and M. O'Sullivan. "Effects of Capillarity and Vapor Adsorption In The Depletion of Vapor-Dominated Geothermal Reservoirs." Proceedings: Seventeenth Workshop ond Geothermal Reservoir Engineering, Stanford University, Stanford, California, SGP-TR-141, pp. 165-174 (1992).

96. G.M. Shook. "Effects of Adsorption on Exploitation of Geothermal Reservoirs," Geothermal Resources Council Transactions, Vol. 18, pp. 339–346 (1994).

97. S. Finsterle and K. Pruess. "Solving the Estimation-Identification Problem in Two-Phase Flow Modeling," Water Resources Research, Vol. 31, No. 4, pp. 913-924 (April 1995).

98. G.M. Shook and J.L. Renner. "An Inverse Model for TETRAD: Preliminary Results," Geothermal Resources Council Transactions, Vol. 26 (2002).

99. T. Xu and K. Pruess. “Modeling Multiphase Non-isothermal Fluid Flow and Reactive Geochemical Transport in Variably Saturated Fractured Rocks: 1. Methodology,” American Journal of Science, Vol. 301, pp. 16-33 (2001).

100. T. Xu et al. “TOUGHREACT User’s Guide: A Simulation Program for Non-isothermal Multiphase Reactive Geochemical Transport in Variably Saturated Geologic Media,” Lawrence Berkeley National Laboratory Report LBNL-55460 (September 2004).

101. T. Xu et al. “TOUGHREACT—A Simulation Program for Non-isothermal Multiphase Reactive Geochemical Transport in Variably Saturated Geologic Media: Applications to Geothermal Injectivity and CO2 Geological Sequestration,” Computers & Geosciences, Vol. 32, pp. 145–165, doi:10.1016/j.cageo.2005.06.014 (2006).

102. J.W. Pritchett et al. “Theoretical appraisal of surface geophysical survey methods for geothermal reservoir monitoring.” Geothermal Resources Council Transactions 24, pp. 617–622 (2000).

103. S.K. Garg at al. “Characterization of geothermal reservoirs with electrical surveys: Beowawe geothermal field.” Geothermics, Volume 36, pp. 487-517, doi:10.1016/j.geothermics.2007.07.005 (2007).

104. Stanford Geothermal Program Proceedings Special Panel on Geothermal Model Intercomparison Study, Report SGP-TR-42, Stanford University, Stanford, California (1980).

105. K. Pruess and R.C. Schroeder. “SHAFT 79 User’s Manual,” Report No. LBL-10861, Lawrence Berkeley Laboratory, Berkeley, California (March 1980).

106. K. Pruess. “SHAFT, MULKOM, TOUGH: A Set of Numerical Simulators for Multiphase Fluid and Heat Flow,” Geotermia, Rev. Mex. Geoenergia, 4 (1), 185–202, Lawrence Berkeley Laboratory Report LBL-24430 (1988).

107. K. Pruess. “TOUGH User’s Guide,” Nuclear Regulatory Commission Report NUREG/CR-4645; also Lawrence Berkeley Laboratory Report No. LBL-20700 (1987).

108. K. Pruess. “The TOUGH Codes—A Family of Simulation Tools for Multiphase Flow and Transport Processes in Permeable Media,” Vadose Zone Journal, Vol. 3, pp. 738-746 (2004).

109. K. Pruess. “TOUGH2 - A General Purpose Numerical Simulator for Multiphase Fluid and Heat Flow,” Lawrence Berkeley Laboratory Report LBL-29400, Lawrence Berkeley Laboratory, Berkeley, California, (May 1991).

110. K. Pruess, C. Oldenburg, and G. Moridis. “TOUGH2 User’s Guide, Version 2.0,” Lawrence Berkeley National Laboratory Report LBNL-43134, Berkeley, California (November 1999).

111. S. Finsterle. “iTOUGH2 User’s Guide,” Lawrence Berkeley National Laboratory Report LBNL-40040, Berkeley, California (January 1999).

112. A. Ghassemi, A. Tarasovs, and A.D.-H Cheng. “Integral Equation Solution of Heat Extraction Induced Thermal Stress in Enhanced Geothermal Reservoirs,” International Journal for Numerical and Analytical Methods in Geomechanics, Vol. 29, pp. 829-844 (2005).

113. Geocrack. www.mne.ksu.edu/~geocrack/.

114. Thunderhead Engineering. www.thunderheadeng.com/petrasim/index.html.

115. M.J. O’Sullivan, K. Pruess, and M.J. Lippmann. “State of the Art of Geothermal Reservoir Simulation.” Geothermics, Vol. 30, No. 4, pp. 395-429 (2001).

116. P.K.W. Vinsome and G.M. Shook. “Multi-Purpose Simulation.” Journal of Petroleum Science and Engineering (1993).

117. S.K. Sanyal et al. “Review of the State-of-the-Art of Numerical Simulation of Enhanced Geothermal Systems.” Proceedings World Geothermal Congress 2000, Kyushu - Tohoku, Japan, 28 May–10 June, pp. 3853-3858 (2000).

118. G.M. Shook. “Numerical Investigations into the Formation of a High Temperature Reservoir.” Proceedings 18th Workshop on Geothermal Reservoir Engineering. Stanford University, Stanford, California, 26–28 January (1993).

119. G.M. Shook. “Vapor Pressure Lowering in Brines and Implications for Formation of a High Temperature Reservoir.” Proceedings 19th Workshop on Geothermal Reservoir Engineering. Stanford University, Stanford, California, 18–20 January (1994).

120. G.M. Shook. “Development of a Vapor-Dominated Reservoir with a ‘High Temperature’ Component.” Geothermics Vol. 24, No. 4. pp 489–505 (1995).

121. G.M. Shook. “New Data File Requirements for Tet-1. Proceedings 28th Workshop on Geothermal Reservoir Engineering. Stanford University, Stanford, California, 27–29 January (2003).

122. G.M. Shook and J.L. Renner. “Preliminary Efforts to Couple TETRAD with Geophysics Models.” Proceedings 27th Workshop on Geothermal Reservoir Engineering. Stanford University, Stanford, California, 28–30 January (2002).

123. G. Nalla, G.M. Shook, G.L. Mines, K.K. Bloomfield. “Parametric Sensitivity Stdy of Operating and Design Variables in Wellbore Heat Exchangers.” Proceedings, Twenty-Ninth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California (2004).

124. K. Pruess, C. Oldenburg, and G. Moridis. “TOUGH2 User’s Guide, Version 2.0,” Lawrence Berkeley National Laboratory Report LBNL-43134, Berkeley, California, November (1999).

125. T. Xu and K. Pruess. “Modeling Multiphase Non-isothermal Fluid Flow and Reactive Geochemical Transport in Variably Saturated Fractured Rocks,” 1. Methodology, American Journal of Science, Vol. 301, pp. 16-33 (2001).

126. J. Rutqvist et al. “A modeling approach for analysis of coupled multiphase fluid flow, heat transfer, and deformation in fractured porous rock,” International Journal of Rock Mechanics and Mining Sciences, Vol. 39, pp. 429–442 (2002).

127. K. Pruess, O. Weres, and R.C. Schroeder. “Distributed parameter modeling of a producing vapor-dominated geothermal reservoir – Serrazzano, Italy,” Water Resour. Res., Vol. 19, pp. 1219-1230 (1983).

128. G. Moridis and K. Pruess. “T2SOLV: An enhanced package of solvers for the TOUGH2 family of reservoir simulation codes,” Geothermics, Vol. 27, No. 4, pp. 415-444 (1998).

129. M.J. O’Sullivan et al. “Fluid and heat flow in gas-rich geothermal reservoirs,” SPE J., Vol. 25, pp. 215-226 (1985).

130. K. Pruess and T.N. Narasimhan. “On fluid reserves and the production of superheated steam from fractured, vapor-dominated geothermal reservoirs,” J. Geophys. Res., Vol. 87, B11, pp. 9329-9339 (1982).

131. D. Swenson, G. Shekhar, and B. Hardeman. “Integration of Poroelasticity into TOUGH2,” Twenty-Ninth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, 26-28 January (2004).

132. D. Swenson et al. “The PetraSim Pre- and Post-Processor for TOUGH2, TETRAD, AND STAR,” Twenty-Seventh Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, 28-30 January (2002).

133. G.S. Bodvarsson et al. The Krafla Geothermal Field, Iceland, 2. The Natural State of the System, Water Resources Research, 20 (11), 1531-1544 (1984).

134. G.S. Bodvarsson et al. The Krafla Geothermal Field, Iceland, I. Analysis of Well Tests Data, Water Resources Research, 20 (11), 1515-1530 (1984).

135. K. Pruess and G.S. Bodvarsson. “Thermal effects of reinjection in geothermal reservoirs with major vertical fractures,” J. Pet. Technol., Vol. 36, pp. 1567-1578 (1984).

136. G.S. Bodvarsson et al. “East Olkaria Geothermal Field, Kenya. 2: Prediction of well performance and reservoir depletion,” J. Geophys. Res., Vol. 92, B1, pp. 541-554 (1987).

137. K. Pruess and T.N. Narasimhan. “On fluid reserves and the production of superheated steam from fractured, vapor-dominated geothermal reservoirs,” J. Geophys. Res., Vol. 87, B11, pp. 9329-9339 (1982).

138. K. Pruess and T.N. Narasimhan. “A Practical Method for Modeling Fluid and Heat Flow in Fractured Porous Media,” Society of Petroleum Engineers Journal, 25 (1), 14-26 February (1985).

139. K. Pruess. "A quantitative model of vapor-dominated geothermal reservoirs as heat pipes in fractured porous rock," Geothermal Res. Counc. Trans., Vol. 9, pp. 353-361 (1985).

140. M.J. O'Sullivan et al. "Fluid and heat flow in gas-rich geothermal reservoirs," SPE J., Vol. 25, pp. 215-226 (1985).

141. K. Pruess et al. "An analytical solution for heat transfer at a boiling front moving through a porous medium," Int. J. Heat Mass Transfer, Vol. 30, pp. 2595-2602 (1987).

142. M.J. O'Sullivan, K. Pruess, and M.J. Lippmann. "State of the Art of Geothermal Reservoir Simulation." Geothermics, Vol. 30, No. 4, pp. 395-429 (2001).

143. K Preuss, editor. Geothermics, Selected papers from the TOUGH Symposium 2003, Berkeley, California, USA, 12-14 May 2003, Volume 33, Issue 4, pp. 399-559, August (2004).

144. T. Xu et al. "Modeling of pyrite oxidation in saturated and unsaturated subsurface flow systems," Transp. Porous Media, Vol. 39, pp. 25-56 (2000).

145. T. Xu and K. Pruess. "Modeling Multiphase Non-isothermal Fluid Flow and Reactive Geochemical Transport in Variably Saturated Fractured Rocks," 1. Methodology, American Journal of Science, Vol. 301, pp. 16-33 (2001).

146. J. Rutqvist et al. "A modeling approach for analysis of coupled multiphase fluid flow, heat transfer, and deformation in fractured porous rock," Int. Journal of Rock Mechanics and Mining Sciences, Vol. 39, pp. 429–442 (2002).

147. J. Rutqvist et al. "Integrated modeling and field study of potential mechanisms for induced seismicity at The Geysers Geothermal Field, California," Geothermal Resources Council Transactions, Vol. 30, pp. 629–633 (2006).

148. C.W. Miller. "Wellbore user's manual," Lawrence Berkeley Laboratory, Report LBL-10910, Berkeley, California, pp. 48 (1980).

149. G. Bjornsson and G.S. Bodvarsson. "A multi-feedzone wellbore simulator," Geothermal Resources Council Transactions, 11, pp. 503–507 (1987).

150. Z.P. Aunzo, G. Bjornsson, and G.S. Bodvarsson. "Wellbore models GWELL, GWNACL, and HOLA user's guide," Lawrence Berkeley Laboratory In: Report LBL-31428, Berkeley, California, pp. 102 (1991).

151. T. Hadgu, R.W. Zimmerman, and G.S. Bodvarsson. "Coupled reservoir-wellbore simulation of geothermal reservoir behavior,"Geothermics, 24, 145-166 (1995).

152. Thunderhead Engineering. www.thunderheadeng.com/petrasim/index.html.

153. UCSD Chemical Geology Group. 30 June 2009 http://geotherm.ucsd.edu/.

154. K. Pruess et al. "TOUGH2 Software Qualification," Lawrence Berkeley National Laboratory Report LBL-38383 (February 1996).

155. K. Pruess and A. Battistelli. "TMVOC, a Numerical Simulator for Three-Phase Non-Isothermal Flows of Multicomponent Hydrocarbon Mixtures in Saturated-Unsaturated Heterogeneous Media," Lawrence Berkeley National Laboratory Report LBNL-49375 (April 2002).

156. K. Pruess et al. "Fluid Flow, Heat Transfer, and Solute Transport at Nuclear Waste Storage Tanks in the Hanford Vadose Zone," Vadose Zone Journal, Vol. 1, No. 1-2, pp. 68-88 (August 2002).

157. K. Pruess and N. Spycher. "ECO2N – A Fluid Property Module for the TOUGH2 Code for Studies of CO2 Storage in Saline Aquifers," Energy Conversion and Management, Vol. 48, No. 6, pp. 1761–1767, doi:10.1016/j.enconman.2007.01.016 (2007).

158. G.J. Moridis, M.B. Kowalsky, and K. Pruess. "Depressurization-Induced Gas Production from Class 1 Hydrate Deposits," SPE Reservoir Evaluation and Engineering (October 2007).

159. J.W. Tester, R.L. Bivins, and R. Potter. "Interwell tracer analysis of a hydraulically fractured granitic geothermal reservoir." Society of Petroleum Engineers Journal, 22, 537 (1982).

160. R.N. Horne and F. Rodriguez. "Dispersion in Tracer Flow in Fractured Geothermal Systems." Geophysical Research Letters, 10, 289 (1983).

161. B.A. Robinson and J.W. Tester. "Dispersed fluid flow in fractured reservoirs: an analysis of tracer-determined residence time distributions." Journal of Geophysical Research, 89 (B12), 10374 (1984).

162. H.D. Murphy et al. "Energy extraction from fractured geothermal reservoirs." Journal of Geophysical Research, 86 (B8), 7145 (1981).

163. J.W. Tester. Proceedings of the Geothermal Program Review IV, September 11-12, Washington, D.C., Conf-8509142 (DE86004074) (1985).

164. G.M. Shook. "Predicting thermal breakthrough in heterogeneous media from tracer tests." Geothermics, v 30, 573-589 (2001).

165. B.A. Robinson and S.A. Birdsell. Proceedings of the Geothermal Program Review V, April 14-15, Washington, D.C. Conf-8704110 (DE88003737) (1987).

166. M.C. Adams and J. Davis, "Kinetics of fluorescein decay and its application as geothermal tracer." Geothermics, vol. 20, p. 53-66 (1991).

167. M.C. Adams et al. "Thermal stabilities of aromatic acids as geothermal tracers." Geothermics, vol. 21, p. 323-339 (1992).

168. B.M. Kennedy et al. "Natural geochemical tracers for injectate fluids at Dixie Valley." Proceedings of the 24th Workshop on Geothermal Reservoir Engineering, Stanford University, SGTP-TR-162 (1999).

169. M.C. Adams et al. "Hydrofluorocarbons as geothermal vapor-phase tracers." Geothermics 30, 747-775 (2001).

170. P.E. Rose, W.R. Benoit, and P.M. Kilbourn. "The application of the polyaromatic sulfonates as tracers in geothermal reservoirs." Geothermics, 30(6), pp. 617-640 (2001).

171. M.C. Adams. "Tracer stability and chemical changes in an injected geothermal fluid during injection-backflow testing at the East Mesa geothermal field." Tenth Workshop on Geothermal Reservoir Engineering, Stanford University, p 247-252 (1985).

172. M.C. Adams et al. "The Dixie Valley, Nevada tracer test." Geothermal Resources Council Transactions, vol. 13, p. 215-220 (1989).

173. M.C. Adams, J.M. Moore, and P. Hirtz. "Preliminary assessment of halogenated alkanes as vapor-phase tracers." Sixteenth Workshop on Geothermal Reservoir Engineering, Stanford University, p. 57-62 (1991).

174. P.E. Rose, M.C. Adams, and D. Benoit. "A tracer test at the Beowawe geothermal field, Nevada, using fluorescein and tinopal CBS." U.S. Department of Energy Geothermal Reservoir Technology Research Program, Abstracts of Selected Research Projects Rept. DOE/EE-0075, March 1995, p. 4.32-4.39 (1995).

175. J.J. Beall, M.C. Adams, and P.N. Hirtz. "Evaluation of R-134a as an injection tracer in the Southeast Geysers." Geothermal Resources Council Transactions, p. 569-573 (1998).

176. M.C. Adams et al. "Alcohols as tracers." Twenty-Ninth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California (2004).

177. Geothermics. Special issue: Tracer applications in geothermal fields (M.C. Adams, editor), Vol. 30, No. 6 (2001).

178. P.E. Rose, W.R. Benoit, and P.M. Kilbourn. "The application of the polyaromatic sulfonates as tracers in geothermal reservoirs." Geothermics, 30(6), pp. 617-640 (2001).

179. P.E. Rose. "The use of polyaromatic sulfonates as tracers in high temperature geothermal reservoirs." Proceedings 20th New Zealand Geothermal Workshop, 239-243 (1998).

180. P.E. Rose et al. "Tracer testing at Steamboat Springs, Nevada, using fluorescein and 1,5-naphthalene disulfonate." Proceedings Twenty-Fourth Workshop on Geothermal Reservoir Engineering, Stanford University, SGP-TR-162 (1999).

181. P.E. Rose et al. "Testing the naphthalene sulfonates as geothermal tracers at Dixie Valley, Ohaaki, and Awibengkok." Proceedings 25th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, SGP-TR-165 (2000).

182. P.E. Rose, S.D. Johnson, and P.M. Kilbourn. "Tracer testing at Dixie Valley, Nevada, using 2-Naphthalene Sulfonate and 2,7-Naphthalene Disulfonate." Proceedings 26th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, SGP-TR-168 (2001).

183. P.E. Rose et al. "Tracer Testing at Dixie Valley, Nevada Using 1-Naphthalene Sulfonate and 2,6-Naphthalene Disulfonate." Proceedings Twenty-Seventh Workshop on Geothermal Reservoir Engineering, Stanford University, SGP-TR-171 (2002).

184. P.E. Rose, M. Mella, and C. Kasteler. "A new tracer for use in liquid-dominated, high-temperature geothermal reservoirs." Geothermal Resources Council Transactions, 27, pp. 403-406 (2003).

185. Greim et al. "Toxicity and Ecotoxicity of Sulfonic Acids." Structure-Activity Relationship: Chemosphere, 28(12), 2203-2236 (1994).

186. M.J.F. Suter. "Trace Determinations of Emerging Water Pollutants." Endocrine Disruptors, Pharmaceuticals and Speciality Chemicals: conference in Basel, Switzerland (1999).

187. M.C. Adams et al. "Stability of methanol, propanol, and SF6 as high-temperature tracers." World Geothermal Congress, p. 3015-3019 (2000).

188. M. Mella et al. "Tracer Test Using Ethanol as a Two-Phase Tracer and 2-Naphthalene Sulfonate at a Liquid-Phase Tracer at the Coso Geothermal Field." Geothermal Resources Council, San Diego, California (2006).

189. M. Mella et al. "The Use of N-propanol as a Tracer at the Site of the Coso Engineered Geothermal System." Proceedings 31st Workshop on Geothermal Reservoir Engineering, Stanford University SGP-TR-179 (2006).

190. R.N. Horne and F. Rodriguez. "Dispersion in Tracer Flow in Fractured Geothermal Systems." Geophysical Research Letters, 10, 289 (1983).

191. B.A. Robinson and J.W. Tester. "Dispersed fluid flow in fractured reservoirs: an analysis of tracer-determined residence time distributions." Journal of Geophysical Research, 89 (B12), 10374 (1984).

192. J.W. Tester. Proceedings of the Geothermal Program Review IV, September 11-12, Washington, D.C., Conf-8509142 (DE86004074) (1985).

193. G.M. Shook. "Prediction of Reservoir Pore Volume from Conservative Tracer Tests." Geothermal Resources Council Transactions, v. 22, p. 477-480 (1996).

194. G.M. Shook. "Prediction of Thermal Breakthrough from Tracer Tests." Proceedings Twenty-Fourth Workshop on Geothermal Reservoir Engineering, SGP-TR-162 Stanford University, Stanford, California, p. 24-30 (1999).

195. G. Nalla, G.M. Shook, and G. Axelsson. "Tracer Test Analysis for Characterization of Laugaland Geothermal Field." Proceedings 30th Workshop on Geothermal Reservoir Engineering. Stanford University, Stanford California. 31 January–2 February (2005).

196. G.M. Shook and J.H. Forsmann. "Tracer Interpretation Using Temporal Moments on a Spreadsheet." INL/EXT-05-00400, September (2005).

197. R.N. Horne et al. "The use of tracers to analyze the effects of reinjection into fractured geothermal reservoirs, "in Proceedings, Geothermal Program Review V, Washington, D.C., 14-15 April, p. 37-52 (1987).

198. National Renewable Energy Laboratory. "Reservoir Engineering." DOE/GO-10098-535, March (1998).

199. G.M. Shook. "A Simple, Fast Method of Estimating Fractured Reservoir Geometry from Tracer Tests." Geothermal Resources Council Transactions, Vol. 27 (2003).

200. K. Pruess, T. van Heel, and C. Shan. "Tracer Testing for Estimating Heat Transfer Area in Fractured Reservoirs." Proceedings World Geothermal Congress 2005, April (2005).

201. G.M. Shook. "A Systematic Method for Tracer Test Analysis: An Example Using Beowawe Tracer Data." 30th Workshop on Geothermal Reservoir Engineering. INEEL/CON-05-02639, January (2005).

202. C. Shan and K. Pruess. "Sorbing Tracers – A Potential Tool for Determining Effective Heat Transfer Area in Hot Fractured Rock Systems." Proceedings 30th Workshop on Geothermal Reservoir Engineering. Stanford University, Stanford, California, 31 January–2 February (2005).

203. G.M. Shook. "Estimating Fracture Surface Areas from Tracer Tests: Mathematical Formulation." Geothermal Resource Council Transactions Vol. 28, 20 August–1 September (2004).

204. S. L. Phillips et al. "A Technical Databook for Geothermal Energy Utilization." Lawrence Berkeley National Laboratory Report LBL-12810, Berkeley, California, 46 pp. (1981).

205. K. Shinohara. "Calculation and Use of Steam/Water Relative Permeabilities in Geothermal Reservoirs." Report SGP-TR-29, Stanford University, Stanford, California (June 1978).

206. C. Satik. "A Measurement of Steam-Water Relative Permeability." Proceedings Twenty-Third Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California (1998).

207. K. Li and R.N. Horne. "Differences Between Steam-Water and Air-Water Capillary Pressures." Proceedings Twenty-Sixth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California (2001).

208. K. Pruess and Y.W. Tsang. "On Two-Phase Relative Permeability and Capillary Pressure of Rough-Walled Rock Fractures." Water Resources Research, Vol. 26, No. 9, pp. 1915-1926, September (1990).

209. P. Persoff and K. Pruess. "Two-Phase Flow Visualization and Relative Permeability Measurement in Natural Rough-Walled Rock Fractures." Water Resources Research, Vol. 31, No. 5, pp. 1175-1186, May (1995).

210. C. Chen, K. Li, and R.N. Horne. "Difference between Steam-Water and Air-Water Relative Permeabilities in Fractures." Geothermal Resources Council Transactions, Vol. 27, pp. 793–800, Geothermal Resources Council (2003).

211. J.B. Hulen and D.L. Nielson. "Hydrothermal Factors in Porosity Evolution and Caprock Formation at The Geysers Steam Field, California: Insight from The Geysers Coring Project." Proceedings Twentieth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California (1995).

212. J.B. Hulen and S.J. Lutz. "Alteration Mineralogy and Zoning in Corehole AWI 1-2 Awibengkok Geothermal System West Java Indonesia." Geothermal Resources Council Transactions, Vol. 23, pp. 19–23, Geothermal Resources Council (1999).

213. P. Persoff and J.B. Hulen. "Hydrologic Characterization of Reservoir Metagraywacke from Shallow and Deep Levels of The Geysers Vapor-dominated Geothermal System, California, USA." Geothermics, Vol. 30, pp. 169–192 (2001).

214. R.N. Horne et al. "The Effects of Adsorption and Desorption on Production and Reinjection in Vapor-Dominated Geothermal Fields." Proceedings World Geothermal Congress, Vol. 3, pp. 1973–1977, International Geothermal Association, Florence, Italy, May (1995).

215. M.S. Gruszkiewicz et al. "Water Adsorption at High Temperature on Core Samples from The Geysers Geothermal Field." Proceedings Twenty-Third Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California (1998).

216. M.S. Gruszkiewicz et al. "Water Adsorption at High Temperature on Core Samples from The Geysers Geothermal Field, California, USA." Geothermics, Vol. 30, No. 203, pp. 269–302 (2001).

217. G.N. Boitnott and P.J. Boyd. "Permeability, Electrical Impedance, and Acoustic Velocities on Reservoir Rocks from The Geysers Geothermal Field." Proceedings Twenty-First Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California (1996).

218. G.N. Boitnott and J.B. Hulen. "Petrographic Controls on Electrical Properties of Core Samples from the Awibengkok Geothermal Field, Indonesia." Geothermal Resources Council Transactions, Vol. 25, pp. 391–394, Geothermal Resources Council (2001).

219. J.J. Roberts, B.P. Bonner, and A.G. Duba. "Electrical Resistivity Measurements of Andesite and Hydrothermal Breccia from the Awibengkok Geothermal Field, Indonesia." Proceedings Twenty-Fifth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, pp. 339-344 (2000).

220. J.J. Roberts et al. "The Effects of Capillarity on Electrical Resistivity during Boiling in Metashale from Scientific Corehole SB-15-D, The Geysers, California, USA." Geothermics, Vol. 30, Issues 2-3, pp. 235–254, April (2001).

221. M. Elkibbi, M. Yang, and J.A. Rial. "Imaging Crack Systems in The Geysers with Shear-Wave Splitting." Geothermal Resources Council Transactions, Vol. 28, pp. 393–398 (2004).

222. M. Wilt et al. "Extended Logging for Geothermal Resources: Field Trials with the Geo-Bilt System." Proceedings Twenty-Seventh Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California (2002).

223. D.A. Blankenship et al. "Update on a Diagnostics-While-Drilling (DWD) System to Assist in the Development of Geothermal Wells." Geothermal Resources Council Transactions, Vol. 28, pp. 153–157 (2004).

224. R. Norman and J. Henfling. "Why Well Monitoring Instruments Fail." Proceedings Thirtieth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California (2005).

225. J.M. Simonson, D.A. Palmer, and R.W. Carter. "Liquid-Vapor Partitioning of NaCl(aq) from Concentrated Brines at Temperatures to 350°C." Proceedings Nineteenth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California (1994).

226. J.M. Simonson and D.A. Palmer. "Vapor-Liquid Equilibrium of Chlorides in Aqueous Systems to High Temperatures: Application to The Geysers Geothermal Field." Geothermal Resources Council Transactions, Vol. 18, pp. 347–352, Geothermal Resources Council (1994).

227. P. Persoff and K. Pruess. "Two-Phase Flow Visualization and Relative Permeability Measurement in Natural Rough-Walled Rock Fractures." Water Resources Research, Vol. 31, No. 5, pp. 1175-1186 (May 1995).

228. G.N. Boitnott. "Core Analysis for the Development and Constraint of Physical Models of Geothermal Reservoirs." Geothermal Resources Council Transactions, Vol. 26, pp. 387–392 (2002).

229. In fluid dynamics and hydrology, Darcy's law is a phenomenologically derived constitutive equation that describes the flow of a fluid through a porous medium. The law was formulated by Henry Darcy based on the results of experiments (published 1856) on the flow of water through beds of sand. (Wikipedia contributors, "Darcy's law," Wikipedia, The Free Encyclopedia, http://en.wikipedia.org/w/index.php?title=Darcy%27s_law&oldid=309214261 [accessed August 21, 2009]).

230. A.K. Verma. "Effects of Phase Transformation of Steam-Water Two-Phase Relative-Permeability." Ph.D. dissertation, University of California, Berkeley (1986).

231. D.A. Palmer, P. Bénézeth, and D.J. Wesolowski. "Aqueous High-temperature Solubility Studies. I. The Solubility of Boehmite as Functions of Ionic Strength (to 5 molal, NaCl), Temperature (100–290°C), and pH as Determined by in situ Measurements." Geochim. Cosmichim. Acta, Vol. 65, No. 13, pp. 2081–2095 (2001).

232. J.M. Simonson, D.A. Palmer, and R.W. Carter. "Liquid-Vapor Partitioning of NaCl(aq) from Concentrated Brines at Temperatures to 350°C." Proceedings Nineteenth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California (1994).

233. Contributed by Horita, Cole, and Weslowski, Oak Ridge National Laboratory.

234. Contributed by Nancy Möller, University of California, San Diego.

235. Z. Duan et al. "The prediction of methane solubility in natural waters to ionic strength from 0-250°C and from 0 to 1600 bar," Geochim. Cosmochim. Acta, v. 56, pp. 1451-1460 (1992).

236. Z. Duan, N. Möller, and J.H. Weare. "An equation of state for the CH4-CO2-H2O system: I. Pure systems from 0-1000°C and 8000 bar," Geochim. Cosmochim. Acta, v 56, pp. 2605-2617 (1992).

237. Z. Duan, N. Möller, and J.H. Weare. "An equation of state for the CH4-CO2-H2O system: II. Mixtures from 50-1000°C and 0-1000 bar," Geochim. Cosmochim. Acta, v. 56, pp. 2619-2631 (1992).

238. Z. Duan, N. Möller, and J.H. Weare. "Equations of state for the NaCl-H2O-CH4 system and the NaC-H2O-CO2-CH4 system: Phase equilibria and volumeteric properties above 573 K," Geocheim. Cosmochim. Acta, v. 67, pp. 671-680 (2003).

239. UCSD Chemical Geology Group. 30 June 2009 http://geotherm.ucsd.edu/.

240. U.S. Department of Energy. "An Evaluation of Enhanced Geothermal Systems Technology," www1.eere.energy.gov/geothermal/pdfs/evaluation_egs_tech_2008.pdf, (2008).

241. International Energy Agency. International Energy Agency Geothermal Implementing Agreement: Strategic Plan for 2002-2007. December 2003.

242. A. Robertson-Tait, C. Klein, and L. McLarty. "Utility Of The Data Gathered From The Fenton Hill Project For Development Of Enhanced Geothermal Systems." Proceedings World Geothermal Congress 2000, Kyushu - Tohoku, Japan, May 28 - June 10, 2000, pp. 3847-3852 (2000).

243. A. Robertson-Tait and J. Lovekin. "Potential Sites And Experiments For Enhanced Geothermal Systems In The Western United States." Proceedings World Geothermal Congress 2000, Kyushu - Tohoku, Japan, May 28 - June 10, 2000, pp. 3841-3846 (2000).

244. U.S. Department of Energy, Office of Geothermal Technologies Strategic Roadmap for the Enhanced Geothermal Systems R&D Program, Working Draft, 27 October (1998).

245. U.S. Department of Energy, Office of Geothermal Technologies Strategic Roadmap for the Enhanced Geothermal Systems R&D Program, Working Draft, 10 February (1999).

246. U.S. Department of Energy (2008). Geothermal Tomorrow 2008. DOE/GO-102008-2633.

247. L.N.Y. Wong. "Crack Coalescence in Molded Gypsum and Carrara Marble. Ph.D. Thesis, Massachusetts Institute of Technology (2008).

248. H.H. Einstein and J.T. Miller. "Experimental and Analytical Research on Fracture Processes in Rock." Final Report on Project DE-FG3606GO16061, (2009).

249. P.P. Wannamaker et al. "Magnetotelluric surveying and monitoring at the Coso geothermal area, California, in support of the Enhanced Geothermal Systems concept: survey parameters, initial results." Proceedings, Stanford Geothermal Symposium, 8 pp. (2004).

250. G. Newman et al. "3D magnetotelluric characterization of the Coso geothermal field." Geothermics, 37, 369-399, doi:10.1016/ j.geothermics.2008.02.006 (2008).

251. V. Maris, P. Wannamaker, and Y. Sasaki. "Three-dimensional inversion of magnetotelluric data over the Coso geothermal field, using a PC." Geothermal Resources Council Transactions, 31, 6 pp. (2007).

252. J.W. Pritchett and T. Ishido. "Hydrofracture characterization using downhole electrical monitoring." Proceedings, World Geothermal Conference, Antalya, Turkey, April (2005).

253. J.W. Pritchett and T. Ishido. "Evaluating Permeability Enhancement Using Electrical Techniques: Final Technical Report for Year 1," submitted by Science Applications International Corporation to DOE, September (2005).

254. J.W. Pritchett et al. "Evaluating Permeability Enhancement Using Electrical Techniques: Final Technical Report for Year 2," submitted by Science Applications International Corporation to DOE, December (2006).

255. J.W. Pritchett. "Guide to the SPFRAC Simulator," submitted by Science Applications International Corporation to the U.S. Department of Energy, September (2008).

256. G. Vlahovic, M. Elkibbi, and J.A. Rial. "Shear-wave splitting and reservoir crack characterization: the Coso geothermal field." Journal of Volcanology and Geothermal Research, 120, 123-140 (2002).

257. M. Elkibbi and J.A. Rial. "Shear-wave splitting: an efficient tool to detect 3D fracture patterns at The Geysers, California." Proceedings, Geothermal Reservoir Engineering, Stanford, 28, 143-149 (2003).

258. M. Elkibbi and J.A. Rial. "The Geysers geothermal field: Results from shear-wave splitting analysis in a fractured reservoir." Geophysical Journal International, 162, 1024-1035 (2005).

259. M. Mella et al. "Calcite Dissolution in Geothermal Reservoirs Using Chelants." Geothermal Resources Council Transactions, San Diego, California (2006).

260. M.A. Stark et al. "The Santa Rosa–Geysers recharge project, Geysers geothermal field, California, USA." Proceedings World Geothermal Congress 2005, paper 2420 (2005).

261. P. Dobson et al. "Temporal changes in noble gas compositions within the Aidlin sector of The Geysers geothermal system," Trans. Geothermal Res. Council, 2006 Annual Meeting, San Diego, California. (extended abstract). LBNL# 60159 (2006).

262. P. Dobson et al. "Evaluation of C-14 as a natural tracer for injected fluids at the Aidlin sector of The Geysers geothermal system through modeling of mineral-water-gas reactions," Proc., TOUGH Symposium 2006, LBNL, Berkeley, California, May 15-17, 2006 (extended abstract). LBNL# 60321 (2006).

263. A.D. Jacobson and C. Holmden. "δ44Ca evolution in a carbonate aquifer and its bearing on the equilibrium isotope fractionation factor for calcite." Earth and Planetary Science Letters, doi:10.1016/j.epsl.2008.03.039 (2008).

264. S.T. Brown et al. "Isotopic constraints on the chemical evolution of geothermal fluids, Long Valley, California," Geothermal Resources Council Transactions, 32, pp.269-272 (2008).

265. R. Bruce et al. "Imaging hydraulic fractures in a geothermal reservoir," Geophysical Research Letters, Vol. 37, LXXXXX, doi:10.1029/2009GL040933, in press (2010).

266. B.R. Julian and G.R. Foulger. "Time-dependent tomography," Geophys. J. Int. accepted for publication (2010).

267. P.E. Rose et al. "The Coso EGS Project—Recent Developments," Proceedings World Geothermal Congress, Antalya, Turkey (2005).

268. Contributed by Ann Robertson-Tait, GeothermEx, Inc.

269. A. Robertson-Tait, C. Morris, and D. Schochet. "The Desert Peak East EGS Project: A Progress Report," Proceedings World Geothermal Congress 2005, Antalya, Turkey, April (2005).

270. A. Robertson-Tait and S. Johnson. "Progress on the Desert Peak East EGS Project," GRC Transactions, Vol. 29, pp. 117-123 (2005).

271. E. Zemach, P. Drakos, and Ann Robertson-Tait. "Feasibility Evaluation of an "In-Field" EGS Project at Desert Peak, Nevada," GRC Transactions, Vol. 33, pp. 285-295 (2009).

272. E.L. Majer and J.E. Peterson. "Application of Microearthquake Monitoring for Evaluating and Managing the Effects of Fluid Injection at Natually Fractured EGS Sites." Geothermal Resources Council Transactions Vol 29, pp. 103-107 (2005).

273. R. Baria et al. "International cooperation to address induced seismicity in geothermal systems," Thirty-First Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California, 30 January-1 February 2006, SGP-TR-179 (2006).

274. E. Majer and J.E. Peterson. "The impact of injection on seismicity at The Geysers California Geothermal Field." International Journal of Rock Mechanics & Mining Sciences, v. 44 (1079-1090) LBNL-61693 (2007).

275. Massachusetts Institute of Technology, "The Future of Geothermal Energy—Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century." INL/EXT-06-11746, ISBN: 0-615-13438-6 (2006).

U.S. DEPARTMENT OF ENERGY
Energy Efficiency & Renewable Energy

EERE Information Center
1-877-EERE-INFO (1-877-337-3463)
www.eere.energy.gov/informationcenter

September 2010

For information on the
Geothermal Technologies Program
visit **geothermal.energy.gov**