Lawrence Berkeley National Laboratory
Recent Work

Title

PROCEEDINGS OF THE TECHNICAL REVIEW ON ADVANCES IN GEOTHERMAL RESERVOIR TECHNOLOGY - RESEARCH IN PROGRESS, BERKELEY, CA, JUNE 14-15, 1988

Permalink

https://escholarship.org/uc/item/62n323jf

Author

Lawrence Berkeley National Laboratory

Publication Date

1988-09-01

eScholarship.org Powered by the California Digital Library
University of California

UC-251
LBL-25635 c.1

Lawrence Berkeley Laboratory
UNIVERSITY OF CALIFORNIA

EARTH SCIENCES DIVISION

LAWRENCE
BERKELEY LABORATORY

NOV 30 1988

LIBRARY AND
DOCUMENTS SECTION

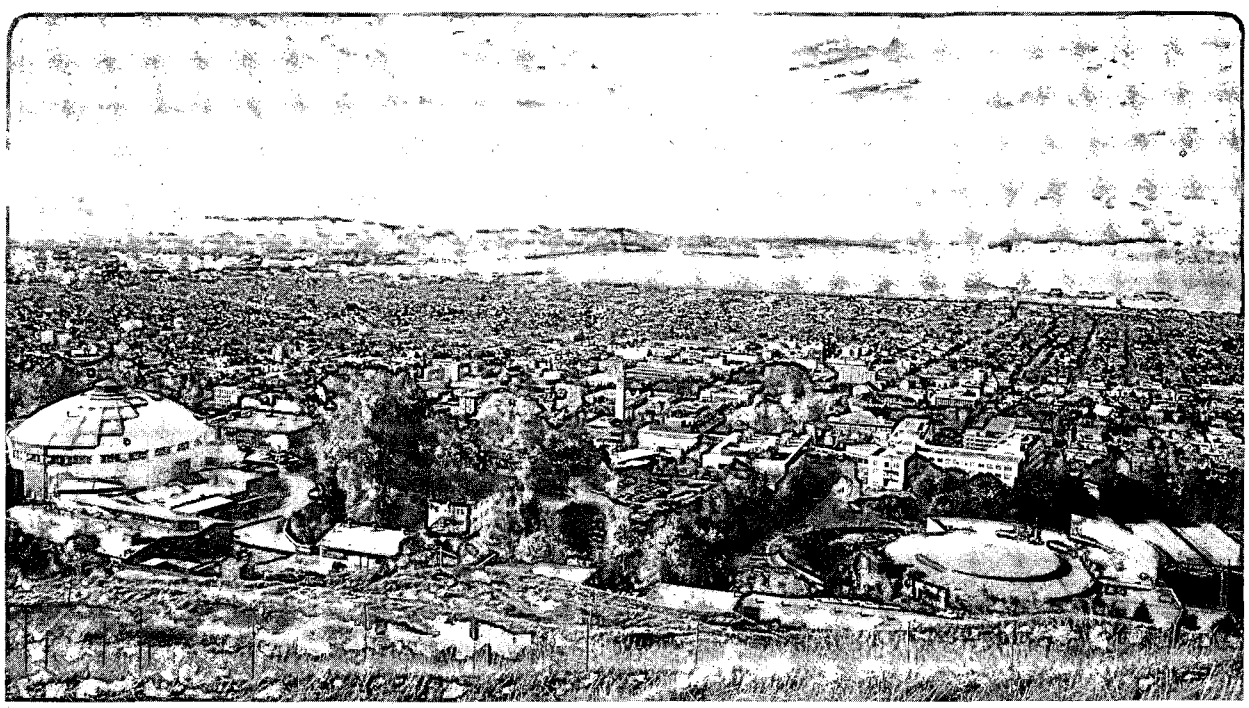
Proceedings of the Technical Review on Advances in Geothermal Reservoir Technology—Research in Progress

Berkeley, California
June 14–15, 1988

September 1988

For Reference

Not to be taken from this room



LBL-25635 c.1

Prepared for the U.S. Department of Energy under Contract Number DE-AC03-76SF00098.

DISCLAIMER

This document was prepared as an account of work sponsored by the United States Government. While this document is believed to contain correct information, neither the United States Government nor any agency thereof, nor the Regents of the University of California, nor any of their employees, makes any warranty, express or implied, or assumes any legal responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by its trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof, or the Regents of the University of California. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof or the Regents of the University of California.

LBL-25635
September 1988

Proceedings of the Technical Review on Advances in Geothermal Reservoir Technology — Research in Progress

Lawrence Berkeley Laboratory
June 14-15, 1988

Marcelo J. Lippmann, Editor
Earth Sciences Division
Lawrence Berkeley Laboratory
1 Cyclotron Road
Berkeley, California

This work was supported through U.S. Department of Energy Contract No. DE-AC03-76SF00098 by the Assistant Secretary for Conservation and Renewable Energy, Office of Renewable Technology, Division of Geothermal Technology.

PREFACE

This proceedings contains 20 technical papers and abstracts describing most of the research activities funded by the Department of Energy's (DOE's) Geothermal Reservoir Technology Program, which is under the management of Marshall Reed.

The meeting was organized in response to several requests made by geothermal industry representatives who wanted to learn more about technical details of the projects supported by the DOE program. Also, this gives them an opportunity to personally discuss research topics with colleagues in the national laboratories and universities.

The two-day review program had ample time for technical discussions and for personal contacts between participants. The atmosphere of the meeting was conducive to the exchange of ideas and the definition of relevant areas of research to industry. The informal flow of comments and suggestions is reflected by the panel discussions held at the end of the meeting, which are included in this proceedings.

This technical review was organized by the LBL Industry Review Panel on Geothermal Reservoir Technology, chaired by Tom Box of the Geysers Geothermal Company. The favorable comments received regarding the review and the enthusiastic participation by industry have encouraged the Panel and LBL to consider organizing similar meetings in the future.

We at LBL are thankful for the constant support for the activities of the Review Panel by the geothermal industry. We will continue doing our best to deserve such support, which has been instrumental to the success of this first technical review. Personally, I am grateful to Diana Parks, Loretta Lizama, Leslie Boyd and Mary Bodvarsson for their help in producing this proceedings.

Marcelo Lippmann
Staff Scientist
Earth Sciences Division

Table of Contents

Opening Session

Welcoming Remarks by Dr. David A. Shirley 3
Introductory Remarks by W. T. (Tom) Box 4
Purpose — Need for Industry Input by Marshall Reed 6

Geology/Geochemistry

Stress in Active Geothermal Systems (M. Lee Allison and Dennis L. Nielson) 11
Illite and Illite/Smectite Uses in Geothermal Systems (Judith M. Ballantyne) 18
Use of Fluid Inclusion Studies in Geothermal Exploration and Reservoir Characterization (Joseph N. Moore and Michael C. Adams) 19
The Prediction of Chemical Scaling in Geothermal Power Operations (John H. Weare and Nancy E. Møller) 23
Geochemistry in Geothermal Reservoir Technology (Alfred H. Truesdell) 28

Geophysics

Seismological Investigations in Geothermal Areas (E. L. Majer) 33
Research in Borehole Geophysics (Phillip M. Wright, Stanley H. Ward, Craig Beasley, Douglas LaBrecque, John S. Stodt, and Howard P. Ross) 40
Geophysical Programs at Lawrence Livermore National Laboratory (Paul W. Kasameyer, Jay Zucca, Steve Jarpe and Teresa Hauk) 51
Geophysical Progress in Fracture Detection and Mapping (Norman E. Goldstein) 53
Magnetotellurics in Deep Geothermal Exploration: Application to the Long Valley Magmatic System (Philip E. Wannamaker) 59
Physical and Chemical Rock Property Measurements in Geothermal Exploration and Reservoir Studies (Alan C. Tripp, Michele M. Lemieux, Phillip M. Wright, Joseph N. Moore, and Howard P. Ross) 65

Reservoir Engineering

High Temperature Instrumentation (Leonard E. Duda) 73

Proposed Downhole Ultrasonic Quadrant Flow Tool: Technology Background and Design Considerations (Lawrence C. Lynnworth) 78

Geothermal Reinjection Research and Instrumentation Development at Lawrence Berkeley Laboratory (Sally M. Benson) 84

Pressure Transient Modeling of Nonuniformly Fractured Reservoirs (Younes Jalali-Yazdi and Ashok Belani) 89

Geothermal Well Testing and Field Case Studies (Gudmundur S. Bodvarsson) 92

FRACSL Research: Past, Current and Future (John D. Miller and Tom M. Clemo) 102

Development of Chemical Tracers for Reservoir Studies (Michael C. Adams and Joseph N. Moore) 107

Optimization of Injection Scheduling in Geothermal Fields (James Lovekin and Roland N. Horne) 110

Simulation Tools for Geothermal Reservoir Engineering (Karsten Pruess) 118

Panel Discussions

Introduction by Jill Robinson-Haizlip — Chairperson 125

Ronald C. Schroeder 125

Joe L. Iovenitti 126

John P. Ziagos 127

Brian A. Koenig 127

Sabodh Garg 128

Jill Robinson-Haizlip 128

Open Discussions 129

Appendices

Appendix 1: Compilation of Recommendations Made During the Meeting 137

Appendix 2: List of Attendees 139

OPENING SESSION

WELCOMING REMARKS

Dr. David A. Shirley
Director, Lawrence Berkeley Laboratory

I am delighted to welcome all of you to Lawrence Berkeley Laboratory (LBL). It is especially gratifying to see such a large turnout for the Geothermal Reservoir Technology Research Review.

I was just talking with Karsten Pruess in the hall, and we were observing that the geothermal program has had its ups and downs over the years. It seems to be quite responsive to the emphasis that is placed on it by the Federal government, and I hope you fellows are poised to strike and rise again like a phoenix from the ashes whenever more supportive winds blow in from Washington. I am confident that you are.

In preparing for this review, I have been reflecting on the fluctuations in the support of geothermal energy for many years and would like to make a few comments regarding the history of the program. I have been bemused and elated at the persistence of this program; I am a strong believer in the need for alternative energy sources. It is obvious that one of these days we are really going to need to cope with the energy problem and it is not going to be done by the rhetoric of politics, but by a technical response. The lead time is such that we cannot wait until we are lined up at the gas stations again wondering where our next drop of petroleum is coming from.

The LBL program in geothermal energy began in 1973 in response to the national goal of developing alternative energy sources for electrical and nonelectrical applications. The program, funded mainly by the DOE, initially consisted of a geophysical assessment of sites in northern Nevada, engineering development of binary-fluid conversion processes and geochemical studies related to brine chemistry, scaling, and corrosion.

Since then, the emphasis of DOE's geothermal program has changed, as has LBL's program. Presently our program is an integrated field, laboratory, and theoretical earth sciences research effort, aimed at developing techniques for delineating and characterizing low- to high-temperature hydrothermal systems to advance the state of the art of reservoir technology. Our research focuses on the development of reservoir engineering methods, which include well testing techniques, laboratory methods, and mathematical modeling tools for analyzing and evaluating geothermal reservoirs. A second aspect of LBL's program involves the development and testing of geophysical instrumentation, field techniques, data processing, and interpretation methods toward improved geophysical detection and mapping of fractures in the subsurface.

During this two-day technical review, which is being organized as part of the activities of the LBL Industry Review Panel on Geothermal Reservoir Technology, reservoir technology research activities carried out at LBL and at other institutions will be discussed. Since 1984, this panel has met approximately every nine months and has served the following functions:

(1) Review DOE's current and planned research activities in geothermal reservoir technology, emphasizing the relevance to industry needs;

(2) Review industry research needs in this field, both near-term and long-term, and determine priorities for these needs;

(3) Assess the possibility for developing DOE-industry cost-share projects; and

(4) Transfer hydrothermal research technology to industry and develop alternative methods for technology transfer.

LBL and DOE have been very encouraged by industry's support of the LBL Review Panel. We are grateful for the time devoted by the panel members who participated in the six meetings held to date and reviewed technical and other documents related to DOE-supported research programs.

By the attendance at this review meeting, I can see that the panel has again received significant support from the geothermal industry. I thank you for this support, and I wish you an interesting and fruitful meeting.

INTRODUCTORY REMARKS

Dr. W. T. (Tom) Box, Jr.
Geysers Geothermal Company
Chairman LBL Industry Review Panel
on Geothermal Reservoir Technology

The few words I have to say this morning revolve around my perception of how the geothermal industry is evolving and where it is headed in the near-term, which is really what we are all concerned about. As you are all aware, this industry over the last few years has changed quite a bit. Domestic geothermal exploration, which flourished in the late 70s and early 80s is almost nonexistent today. International exploration, however, does continue in some areas. The number of major companies involved in the business has decreased. Phillips got out of the business in 1985, and recently Thermal Power basically did also. Many of the remaining larger companies have reduced their staff. I know the company I worked for, Geysers Geothermal, has been through that and also UNOCAL.

However, the smaller entrepreneurial companies seem to be doing well. Many of them have significant projects ongoing today. In this light, a number of new projects are coming online, in The Geysers, Coso Hot Springs, the Imperial Valley, and in Nevada. These projects, which are inducing quite a bit of activity (almost a miniature boom in the industry), are the results of the favorable economics derived from Standard Offer #4 contracts. These are fixed rate power sales contracts, which have five-year activation term, and most of these contracts were taken in the 1984-85 time frame. So most contracts will expire in the 1989-90 time frame. The frenzy of activity that you see now in the Imperial Valley and in some areas of The Geysers, and particularly down in Coso, relates to the near-term ending of those contracts. So, what we really have to look at in the near-term is what this industry is going to be like after the Standard Offer #4 window is closed. Which is basically next year, or for some, the year after.

Abundant, cheap power is available to most utilities in the west; therefore, the geothermal industry is going to have to be more competitive to make that form of power production economical and competitive. New geothermal developments are going to be structured, more and more, by power sales contracts, not energy sales contracts. This involves large amounts of capital, as it involves the construction of power plants. So, the Standard Offer #4 bubble, if you will, has carried us along for the last few years, but that bubble is going to burst here in the next year or so, and then the industry is going to be faced with the real world, competing economically with other sources of energy.

The DOE funded research, I feel, should be directed at primarily the near-term reduction of costs, both development costs and operating costs. Also important in this is developing the means to optimize or extend the life of the presently developed reservoirs. This is becoming increasingly more and more important in The Geysers. Finally, much of the new geothermal development will necessitate third party financing. The bankers (I know from my recent experiences) will all ask, "How long is this going to last? What are your reserves?" Geothermal reserves and field life are very hard things to pin down, and I think as an item in which research should be directed, it is also a significant one. Also this research should, hopefully, enable the development of the lower quality resources which presently are not developed in this new, tighter economic climate.

So, specifically, from my point of view, the DOE funded projects, which have the greatest potential for near-term impact on our industry and to the development and operating costs, are in improvements in drilling technology. I think hard rock penetration work that has been done is excellent, specifically the development of bits to withstand the environment that we work in; downhole motors and downhole packers that facilitate the ability to secondarily stimulate some of these reservoirs are important. The handling of corrosion, or erosion in some

cases, and scale control through developments in chemistry and metallurgy are also extremely important. In many cases, these conditions drive the economics of our projects. This is particularly true in these high temperature fields where siliceous scaling is a problem.

The projects involving the optimization of field development are also important, in particular, and one of the things that has frustrated me most over the years is the inability to map fracture orientations in the wells. Most geothermal reservoirs are fracture dominated, yet not very much is known about the orientation of those fractures in the subsurface. So fracture mapping capabilities in wellbores would definitely help us improve the geologic models.

The optimizing of field development also benefits from the experiences and technology transfer that results from studies of foreign fields. The work that has been done in Cerro Prieto and Los Azufres has been very significant. Another topic that is influencing our ability to optimally develop these fields is the geochemical evolution of the fields (be it hot water or the vapor dominated fields) as they are produced.

I mentioned the other category of reserves and field life. Reservoir modeling is becoming more and more important, as we get more and more real data. I think computer codes used to model these phenomena are important. What we must keep in mind is that these computer codes, in order to be useful to any of us, have to be easy to use. I know a lot of the computer codes that have been developed are very sophisticated and provide lots of insight, but they can be very difficult for the industry people to use.

Modeling studies are crucial, as I mentioned, in evaluating the field life, and also in optimizing field development. The development of stable, cheap tracers for steam and brine is important. I emphasize the word cheap; a lot of tracers that do seem to work are quite expensive, but again cost is a prominent consideration in our business. Heat transfer modeling and heat recovery is also very important; again, the modeling and the computer codes must be easy to use. They are of no use to anyone if they are too complicated to understand.

Finally, equally important is the understanding of physical and chemical effects in the reservoirs around the injection wells. How to monitor the movement of fluids by geophysical monitoring of injection is also another important issue. In a period of declining budgets, it is also important to focus on cost-shared projects. I think there has been a lot of benefit from cost-shared projects, and hopefully this aspect of Industry/DOE cooperation will continue to evolve.

The programs that I have outlined I believe will provide the most significant near-term benefit to our industry. I think it is up to the Industry Review Panel to attempt to focus the DOE in the direction that I have indicated.

The last thing I would like to say is that generally in a meeting I attempt to appraise the potential for success of the meeting by the ratio of the research people to the industry people. And, if there is more than four researchers per industry type, the meeting will get a little bit away from us. But I see that ratio as less than four, and so I think we will have a good meeting.

PURPOSE — NEED FOR INDUSTRY INPUT

Marshall Reed
Geothermal Technology Division, CE-342
U.S. Department of Energy
Washington, DC 20585

I greatly appreciate the opportunity to come to this meeting with representatives of the geothermal industry. I am a program manager for the Department of Energy (DOE) in Washington, DC, and I do not have the opportunity to discuss geothermal research with industry representatives as often as I would like. I began my research in geothermal energy about 20 years ago as a graduate student at the University of California, Riverside. Many of the research problems that limited our understanding of geothermal resources at that time are still with us, but we have made great progress in the development of geothermal resources and in solving many of the basic research problems. I believe that the DOE research program in Geothermal Reservoir Technology gives us the opportunity to solve many of those remaining problems.

Tom Box, Geysers Geothermal Company, mentioned some of the ways that we have used to stretch Federal funding available for reservoir research. One of the major ways to accomplish more is cost sharing with the geothermal industry. In the past, the DOE geothermal research programs would drill their own wells, conduct their own testing, and be faced with the large costs involved. Now we have joint research projects with industry where cost sharing allows more research to be conducted than otherwise possible. The greatest advantage with joint research is not the cost sharing, it is the strong industry involvement in the research program from the beginning to the end.

The LBL Industry Review Panel has an important role in the development of reservoir technology research — the identification of major problems facing the geothermal industry. This Panel is asked to review the research that is being funded by DOE to see if it is compatible with industrial needs. If these needs are not being met, the Panel is able to make suggestions and recommendations on how best to change the research and how to tailor the research program so that it does.

The DOE funds several geothermal research activities that are not directly related to hydrothermal resources: the Geopressured Research Program is investigating the methane and heat available in brines beneath the Gulf Coast, the Hot Dry Rock Research Program is examining the extraction of heat from crystalline rocks at Fenton Hill, New Mexico, and the Magma Energy Program is conducting research that may lead to the recovery of heat from molten rock. This research is of high risk, and it is not expected to have application to our energy production for some 20 or 30 years. Tom Box mentioned that the real concern today is just keeping the geothermal industry alive. If there were no geothermal industry, geopressured, hot dry rock, and magma would not have the developers to carry on past the research phase. We must maintain a vital geothermal industry so that in 20 or 30 years, when these other fields of endeavor mature, there is an industry to develop the resource.

Of greatest interest to the geothermal industry is the research funded by the DOE that pertains to hydrothermal resources: the Hard Rock Penetration Research Program conducts development and testing of new drilling technology and new instrumentation; the Advanced Brine Chemistry Research Program is investigating mechanisms and controls for scaling, corrosion, and safe waste disposal; and the Heat Cycle Research Program is involved in testing and analysis of equipment and materials for energy conversion. The topics of exploration, field development, and field management fall under the research activities of the Reservoir Technology Research Program. I coordinate this program for the Geothermal Technology Division of DOE, and I rely heavily on the

management skills of people in the DOE Idaho Operations Office and on the research skill of the investigators in several National Laboratories and Universities. Most of the researchers presenting information to you during this meeting have been funded by the Reservoir Technology Program. Many of these researchers are not funded full-time by the geothermal program, but they receive funding from other major research programs in DOE.

The National Laboratories have attracted top research people and have some of the best quality research facilities in the world. These labs are appropriate to conduct much of the high technology research needed for geothermal development, and their computing facilities are excellent. Universities also have an important role in the Reservoir Technology Research. The geothermal industry has benefited from the training and transfer of new technology by employing graduates of the several university research projects.

All of the researchers in the Reservoir Technology Program are encouraged to present the results of their work to the geothermal industry at technical meetings and in the scientific literature. The best forums we have found to inform industry of our accomplishments have been the Stanford Reservoir Engineering Workshops and the Geothermal Resources Council annual meetings. The various annual meetings are all important for the presentation of completed research. At this meeting, you will hear presentations on current research in progress. The researchers will discuss their active research topics and will describe how they see their research answering the needs of industry. I hope that you will see how the results of this current research will reduce the operations costs for the geothermal developers, how the research will make geothermal exploration more effective, and how this research will help in the development of geothermal fields.

In the Reservoir Technology Program there are five major research organizations.

(1) The Lawrence Berkeley Laboratory has been conducting reservoir engineering and geophysics research in geothermal systems for many years.

(2) The Lawrence Livermore National Laboratory is involved in several small research projects in geophysics and instrument development.

(3) The Idaho National Engineering Laboratory is investigating some new approaches in reservoir engineering.

(4) The Petroleum Engineering Department of Stanford University has provided most of the reservoir engineers now working in the geothermal industry and is continuing research in reservoir measurements and processes.

(5) The University of Utah Research Institute brings to the research program the tools of the mining industry in their research in geophysics, geochemistry, and geology.

The U.S. Geological Survey funds its own geothermal research program and, when the objectives are closely related, the DOE Geothermal Program will share the funding of some USGS research projects. For example, we are able to partially support the geochemical work of Alfred Truesdell to expand his project into geothermal fields in Mexico and Italy.

The Reservoir Technology Program also provides additional funding to groups doing research in geochemistry of geothermal systems, supplementing their NSF grants. David Crerar of Princeton University receives DOE funds that allows him to continue the study of quartz and albite solution kinetics in various salt concentrations that are similar to geothermal systems. This research will provide the data necessary to model rate-dependent irreversible processes related to the production and injection of geothermal fluids. It is expected that these studies will allow better prediction of the precipitation and dissolution of quartz and albite in geothermal reservoirs and the effect of mineral changes on reservoir permeability. The research of Philip Candela of the University of Maryland on vapor evolution from silicic magmas is also partially supported by DOE. This funding provides for the modeling effort to define the nature of magmatic vapor evolution and the characteristics of vapor composition that may be detected in hydrothermal systems above magma bodies. The objective is to develop generalized predictive models of element partitioning between vapor, melt, and crystal phases. It is hoped that the project will provide concentrations of some trace elements that could be expected to appear in hydrothermal solutions if there is a magmatic contribution.

Three dedicated researchers in the Reservoir Technology Program visited industry personnel and asked them to respond to a survey of industry needs. Mike Wright, UURI; Marcelo Lippmann, LBL; and Joel Renner, INEL, spent a great deal of time and effort in trying to determine the research needs from the industry perspective. This is an ongoing process, and we hope that you will communicate with us about your perception of needs in geothermal research. I will summarize the results of this survey (Table 1), and I would appreciate comments or suggestions that would add to this study. People in many aspects of the geothermal industry responded to this survey, and it includes reservoir engineers, geologists, geochemists, geophysicists, and production managers. You can see that the position held by the person responding had a strong effect on the priority of research needs.

In both geochemistry and reservoir engineering you will notice that there is a concern about scaling and precipitation of solids either in the wellbore, in production equipment at the surface, or in the geothermal reservoir. Part of the problem of precipitation of solids falls under the Research Technology Program.

In my mind, geothermal reservoir engineering should encompass all types of research that pertains to the reservoir. You need a conceptual geologic model of how the reservoir works; this provides the basic framework on which you can hang all of your information. The processes of fluid flow and of the chemical changes occurring in the fluid then allow you to characterize the resource and to define the reservoir. From this basis, you can then predict the response to exploitation and the useful lifetime of the reservoir. From this integrated understanding, you have the predictive capability to determine the useful lifetime of a reservoir under different development schemes. From our survey, it appears that more researchers in industry are looking at the integrated picture of a geothermal reservoir and are suggesting research across discipline boundaries to solve major problems.

Table 1

GEOTHERMAL INDUSTRY NEEDS SURVEY SUMMARY (23 RESPONSES)

Geochemistry

1. Scaling
2. Chemical effects of exploitation
3. Chemistry and thermodynamics of hypersaline fluids
4. Corrosion
5. Sampling liquids and gases

Reservoir Engineering

1. Research on reservoir processes
2. Methods to characterize reservoir properties and conditions
3. Predicting reservoir productivity, longevity and total production potential
4. Field case studies
5. Predicting scaling

Geology

1. Structural controls on permeability
2. Mapping fractures in boreholes
3. Determining fluid content and capacity of fractures during drilling
4. Integrated case studies
5. Structural controls on intrusion

Geophysics

1. Monitoring reservoir changes during production
2. Geophysical monitoring of injection
3. Well logging instrumentation and interpretation
4. Cross borehole and borehole-to-surface methods
5. Geophysical exploration for hidden systems

GEOLOGY / GEOCHEMISTRY

Session Chairperson

Jill Robinson-Haizlip
(GEO Operator Corporation)

STRESS IN ACTIVE GEOTHERMAL SYSTEMS

M. Lee Allison and Dennis L. Nielson

University of Utah Research Institute, 391 Chipeta Way, Suite C,
Salt Lake City, UT 84108

ABSTRACT

Borehole breakouts form in response to in-situ stresses and define the principal stress orientations. Horizontal stresses imposed on the rock are concentrated at the borehole margin, perpendicular to the direction applied. Breakouts result from tensile and shear failure at the stress concentration points.

Multiple stress fields separated by faults are present in wells in Roosevelt Hot Springs, Cove Ft.-Sulphurdale, and Baca geothermal fields. The stresses are independent of regional forces and appear to be directly related to local or adjacent faults.

Determination of individual stress blocks allows prediction of hydrofrac direction, and discrimination of intervals favorable for pressure maintenance or waste injection.

INTRODUCTION

Understanding the state of stress in geothermal systems is critical for determining hydrofrac directions, predicting whether fractures will be open or closed, and for planning reinjection. Until recently determining in-situ stress in a borehole was a relatively expensive and time-consuming process which resulted in only a few discrete measurements in any borehole. However, since the recognition of stress-induced borehole breakouts [1] it is possible to determine in-situ stress orientation over major intervals of the borehole using oriented caliper logs (e.g. dipmeter and fracture identification logs).

The vast majority of breakout analyses have used logs from petroleum wells that reveal a generally uniform stress field of regional extent.

Our studies of breakouts in geothermal wells show conversely, not only significant changes in stress orientation between wells in a field but also within individual wells. This has important consequences for exploration and development of geothermal resources.

BREAKOUT ANALYSIS

Breakouts are zones of borehole elongation that develop in response to in-situ stress concentrations on the borehole wall. Any stress acting on a point may be resolved into three mutually perpendicular stress directions, the greatest, intermediate, and least principal stress directions ($\sigma_1, \sigma_2, \sigma_3$ respectively). One of these is normally vertical, the other two horizontal. Whether the vertical stress, S_V, is σ_1, σ_2, or σ_3 determines whether faulting is normal, strike-slip, or thrust.

It was shown in the late nineteenth century that a horizontal stress acting on a plate with a circular hole in it would concentrate at the hole's edge 90° from where it was applied. The stress concentration is three times that applied. Tensile and shear failure shatters the rock, resulting in a preferential borehole elongation. This elongation is thus in the direction of the minimum horizontal stress, S_h, and perpendicular to the maximum horizontal stress, S_H.

During wireline logging the four-arm caliper normally spins as it comes up the borehole, making a full 360° rotation approximately every 50-100 feet. In the presence of a breakout though, one of the calipers locks into the elongated part of the wall stopping the tool rotation. This, coupled with the differential hole elongation of a few tenths of inches or more indicated by the two sets of calipers, defines the breakout. Of course, there are minor complications and ambiguities that can cause misreadings but these are the fundamental characteristics.

STRESS FIELDS IN GEOTHERMAL WELLS

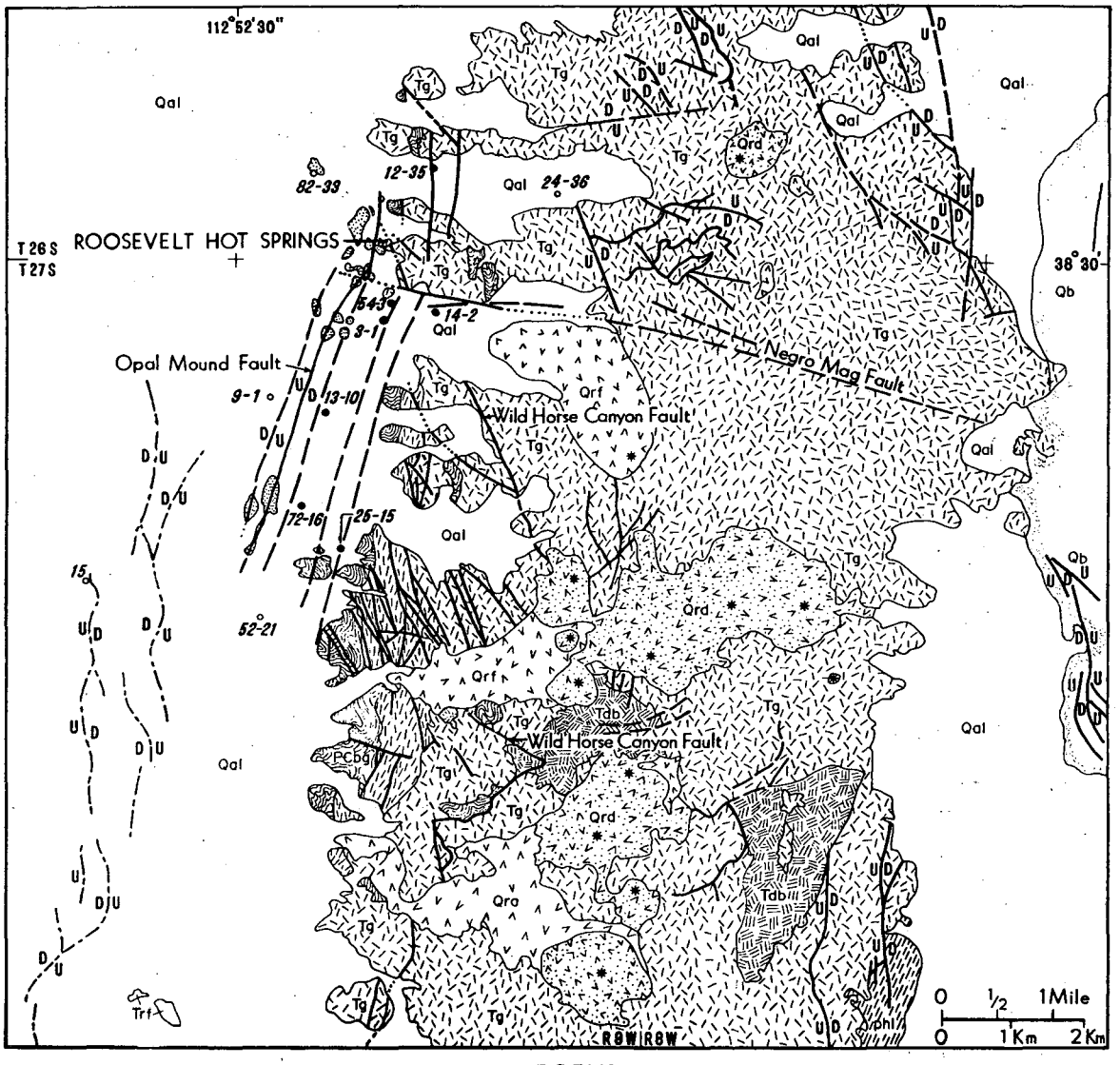
Roosevelt Hot Springs

Geothermal production at Roosevelt Hot Springs in southwest Utah is from fractured Precambrian gneisses and Tertiary to Recent volcanic rocks along the Opal Mound and Negro Mag faults

(Figure 1). North to northeast trending normal faults parallel to the Opal Mound fault are the youngest structures in the area and control present fumarolic activity.[2] The Negro Mag fault, an east-west trending high-angle normal fault is probably the surface expression of a deep-seated basement trend.

The only available oriented caliper log, a fracture identification log, is from the Getty KGRA 52-21 well in Sec. 21, T27S, R9W, at the south end of the Opal Mound system. Forty-six (46) breakouts were identified in the interval from 2076' to TD at 7516'. Breakouts occurred over 1173' of the 5529' logged, 21% of the total. Average length of a breakout is 25.5' but they vary from 4' to 138'.

A frequency vs. azimuth plot of the breakouts (Figure 2) shows a wide distribution of orientations that can better be understood in a length vs azimuth plot (Figure 3). Three major



LEGEND

Qal — alluvium, siliceous sinter	Trf — rhyolite flows
Qb — basalt	Tg — granite, quartz monzonite, & syenite
Qrd — rhyolite domes, with centers	Tdb — diorite
Qra — pyroclastic deposits	phl — metasediments
Qrf — rhyolite flows	PCbg — banded gneiss

Figure 1. Geologic map of Roosevelt Hot Springs KGRA and vicinity[2].

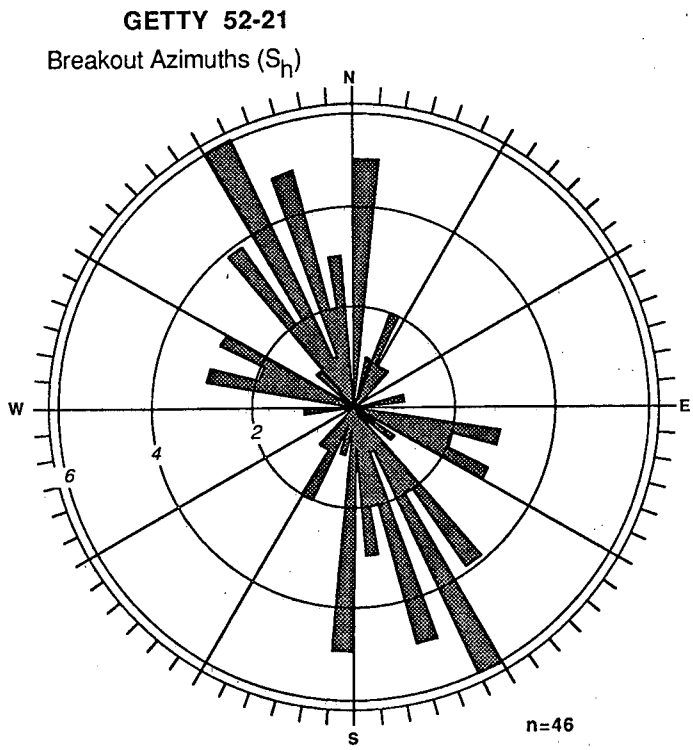


Figure 2. Breakout frequency vs. azimuth plot for Getty well 52-21, Roosevelt Hot Springs, for the interval 2076'-7516'. All breakouts are in Precambrian gneisses.

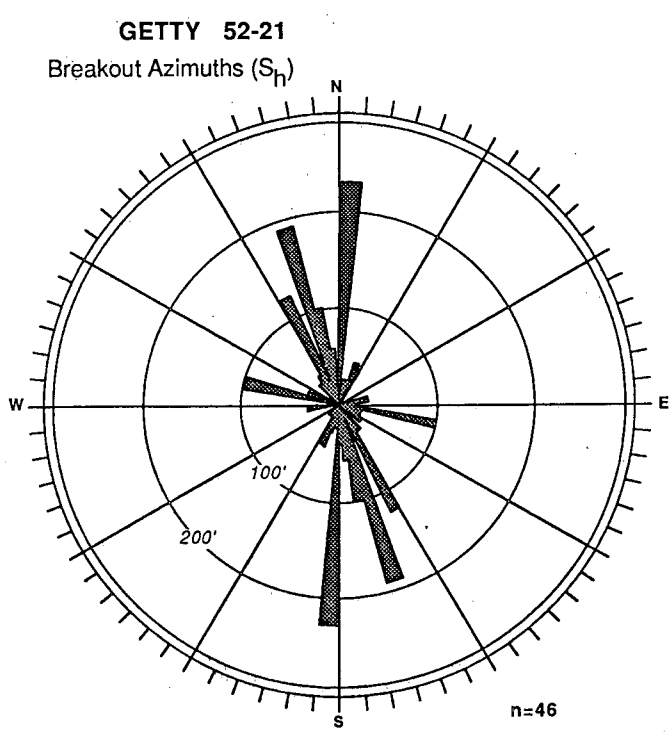


Figure 3. Length vs. azimuth plot of data in Figure 2.

trends are recognized. Recalling that in an extensional environment faults will theoretically form parallel to the S_H direction, breakouts (in the S_h direction) will be perpendicular to the faults. Thus, breakouts trending 0-5° are perpendicular to the Negro Mag trend, those at 100-120° relate to the Opal Mound trend, and the large cluster in the 140-175° range do not correspond to any mapped surface structural features. This latter group however, does correlate with some strain measurements made 1.5 miles to the southeast by overcoring in Precambrian gneiss.[3]

The wide azimuthal range of breakouts argues that a number of local stress fields are present in the Roosevelt Hot Springs area. The vertical distribution of the breakouts (Figure 4) show sys-

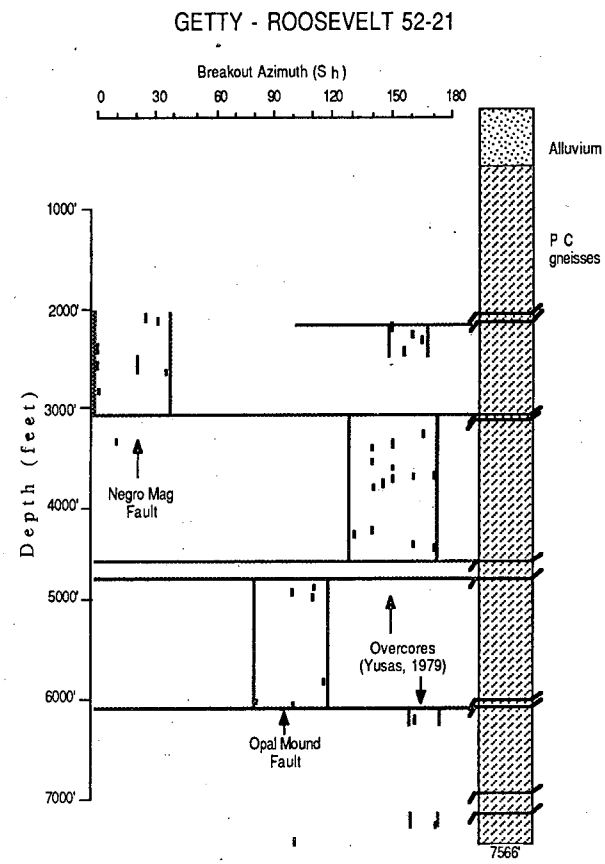


Figure 4. Vertical distribution of breakouts in well Getty 52-21, Roosevelt Hot Springs. Lithologic column is derived from well cuttings. Vertical dashed lines mark azimuthal limits of a breakout group. Horizontal dashed lines mark depth limits of a breakout group and correspond to faults identified independently on well logs and in lithologic descriptions. Fault trends that are related to the breakout groups are labelled.

tematic changes in breakout direction (and stress direction) at fault breaks in the well. Faults were independently identified from other logs and cuttings evidence. It appears that the stress field is reoriented at faults and that fault bounded blocks of rock have a generally uniform stress field.

Cove Ft. Sulphurdale

Utah's other major geothermal center, Cove Ft.-Sulphurdale, lies just a few miles northeast of Roosevelt Hot Springs, in a similar tectonic environment. Generally north to north-east trending normal faults terminate against the high-angle east-west trending Cove Creek fault (Figure 5). Complex fault patterns south of the Cove Creek fault result from low-angle gravity sliding. Geothermal production is confined to areas along the two major fault trends. Reservoir rocks are Cambrian to Triassic sediments.

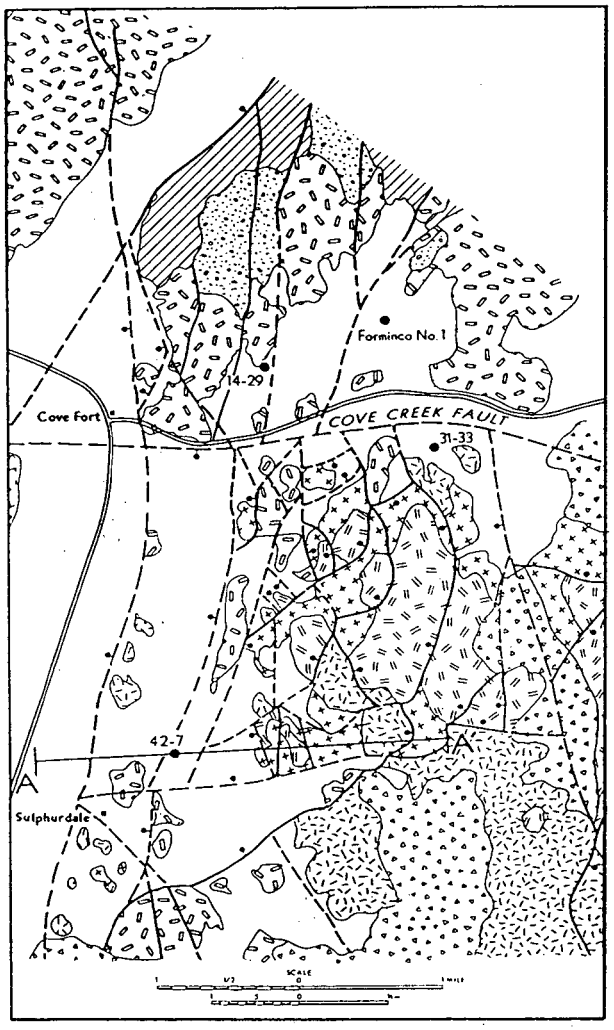


Figure 5. Geologic map of Cove Fort-Sulphurdale geothermal field showing principal faults and wells[4]. See Reference 4 for description of lithologic units.

Studies [5] of the active seismicity within the region concluded that the regional orientation of the least principal stress is 102°. It was also determined that the maximum and intermediate principal stress directions are similar in magnitude and change orientation through the region between vertical and NNE-SSW.

Dipmeter logs are available in three wells drilled by Union Oil Co., CFSU #31-33, #14-29, and #42-7. CFSU #31-33, located adjacent to the Cove Creek fault has three distinct breakout trends (Figure 6). The largest, NE-SW trending, is perpendicular to the Cove Creek fault. The second set, NW-SE trending, is perpendicular to some of the curvilinear faults in the gravity slide block. The smallest breakout set, roughly E-W trending corresponds to the main Basin and Range extensional faulting.

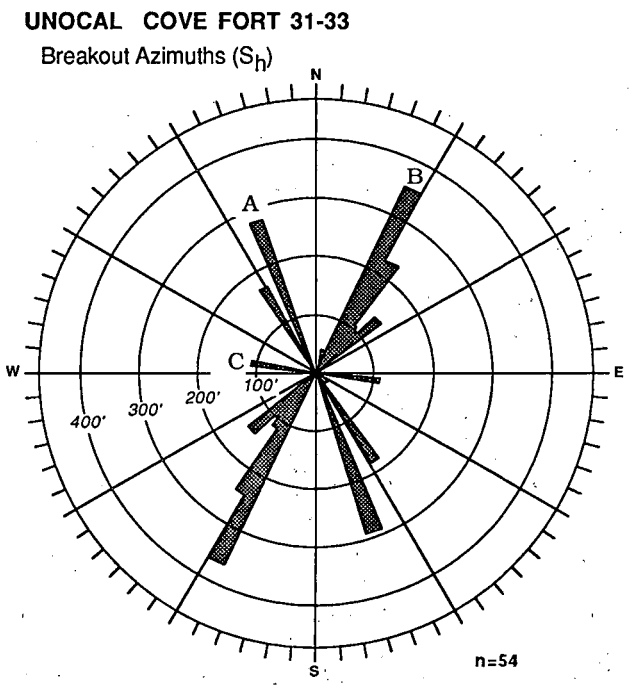


Figure 6. Length vs. azimuth plot of breakouts in Unocal well 31-33, Cove Fort, for interval 2137'-5188'.

Vertical distribution of breakouts in the well again reveals that the stress field is abruptly reoriented at fault zones (Figure 7). Blocks of rock between faults have relatively uniform stress fields.

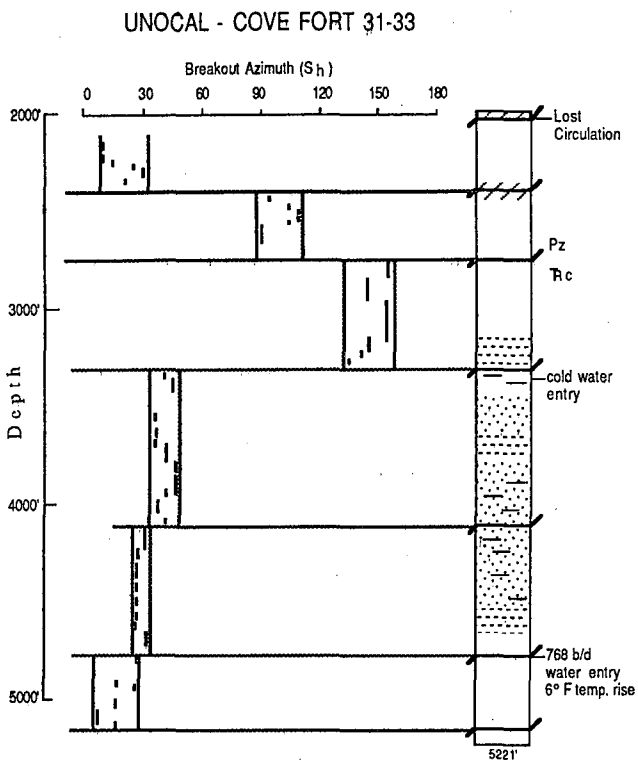


Figure 7. Breakout azimuths in well Unocal 31-33, Cove Fort, as a function of depth. See Figure 2 for full figure description. Blank areas on lithologic log indicate no sample due to lost circulation.

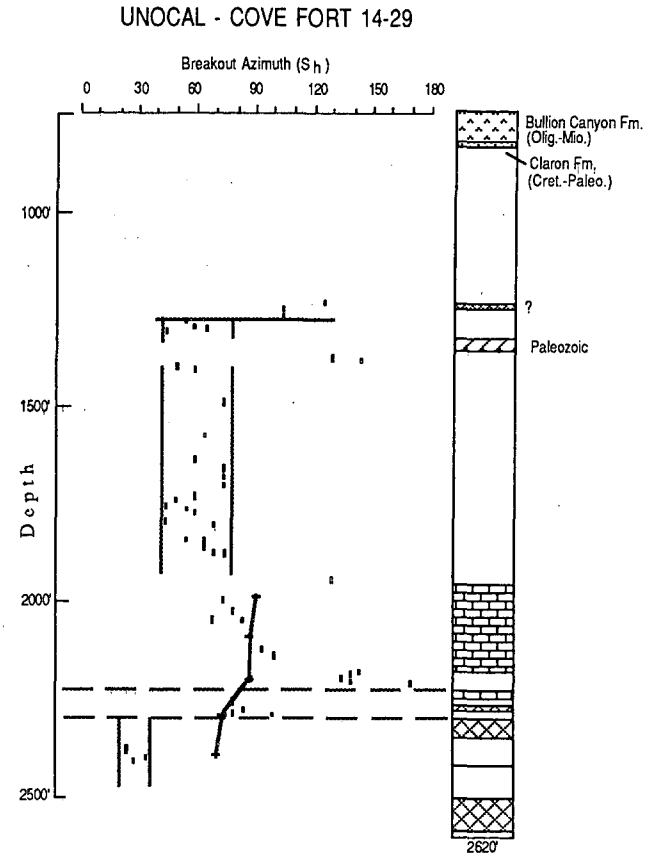


Figure 8. Breakout azimuths in well Unocal 14-29, Cove Fort, as a function of depth. See Figures 2 and 7 for full figure description. Irregular line below 2000' shows orientation of well deviation.

CFSU #14-29 drilled into an area of NNW to NNE trending normal faults north of the Cove Creek fault. Breakouts are overwhelmingly centered along N60E (Figure 8). Extensive lost circulation during drilling precludes identifying potential faults from cuttings. Two other problems exist with the well. First, breakouts at shallow levels commonly are scattered due to near-surface effects. Second, many breakouts below 2000' roughly parallel the well deviation suggesting they are elongations formed by bit drag on the borehole wall.

The significance of this well lies not in stress changes within the well but rather that the breakouts in #14-29 are unrelated to those in #31-33, little more than a mile away.

Well CFSU #42-7, to the south, is pervasively faulted. Unfortunately, breakouts are not extensively developed but those present are widely scattered in orientation (Figure 9). The one well-defined group of breakouts around 3500' depth are similar to those seen in well #31-33 related to the major Basin and Range normal faults.

Nowhere are there any indications of a minimum stress direction of 102° as reported from seismicity data. Instead, most of the breakouts can be related to local fault trends. Stresses change across nearly all faults within single wells and across faults between wells.

Baca

The Baca geothermal field lies in the Valles Caldera in the Rio Grande rift of New Mexico. Production is from fractured Tertiary andesites and tuffs. Fault patterns are complex, curvilinear, and not fully understood.

Breakouts have been catalogued in four wells and demonstrate the same relationships as seen in the Utah wells, although it is more difficult to relate breakout trends to specific faults.

Rather than detailing the breakouts in the Baca wells, one short interval will be discussed which demonstrates some of the potential of this technique.

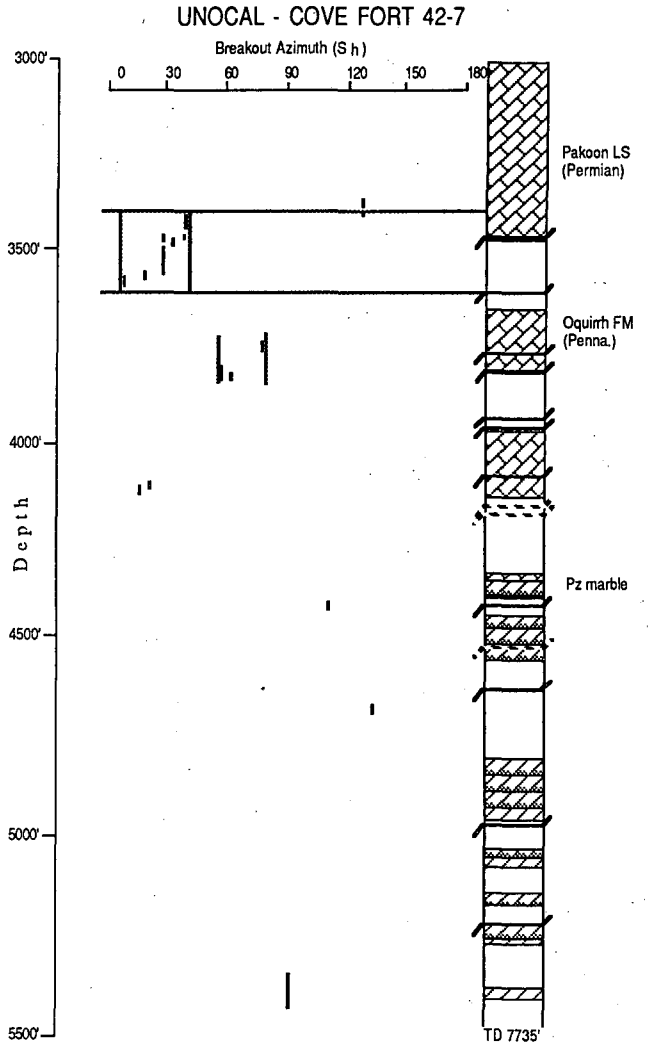


Figure 9. Breakout azimuths in well Unocal 42-7, Cove Fort, as a function of depth. See Figures 2 and 7 for full figure description.

The Baca 20 Redrill was logged, hydrofractured, and relogged, a situation that has not been encountered in any other geothermal well. Breakouts in the lower Bandelier Tuff lie in the 90-120° range whereas those in the underlying andesite trend 160-180° (Figure 10). The basal couple of hundred feet of the Bandelier Tuff was hydrofractured as part of the well completion and another dipmeter log run. As predicted by theory, the hydrofracs were generated 90° from the breakout trend (Figure 11). These manifested themselves as borehole elongations similar to breakouts. At the same time additional elongations were found in the same trend as the original breakouts, 90° from the hydrofracs. Re-examination of the original dipmeter log showed that small elongations existed which became enlarged after the hydrofrac. The criteria for listing a breakout required that the hole elongation was at least 0.5 inches greater than the nominal hole size indicated by the second caliper. A number of differential elongations of about 0.2 inches were ignored as not being significant. However, as a result of the hydrofrac they were enlarged to $\geq$ 0.5 inches and became quite prominent.

The Baca 20 R/D not only demonstrates the theoretical basis for breakout formation but also forcefully shows the value of even subtle elongations.

INTERPRETATION

Multiple, fault-bounded stress fields are present in all geothermal systems studied. Ongoing work shows the same situation in fields in California and Nevada. The stress fields are independent of regional stresses and appear to be related to local faults or fault systems. Faults that act as boundaries between two different stress directions must be free surfaces across which stresses are not transmitted. Tractions across the fault will tend to keep it open, maintaining a permeable reservoir or conduit for fluids.

The presence of multiple stress systems in geothermal fields was unexpected based on previous studies on petroleum wells which found uniform regional stresses. Restriction of multiple stress systems to active geothermal areas that are fracture controlled strongly suggests that thermal stresses produced by hydrothermal fluids in faults and fractures are the cause of the local stresses. This is an area of present research.

IMPLICATIONS

Breakout analysis allows a quick, cheap, reliable way to determine in-situ stress orientations over major intervals of a well. With this information hydrofracture directions can confidently be predicted. Wells that are open to production throughout their length should be re-evaluated based on stress blocks. A block of rock in the well with a stress field related to a producing fault or fracture system can be injected into for recharge and pressure maintenance. On the other hand, such a block should not be used for injection of disposed fluids. Instead disposed fluids should be injected into blocks of rocks with stress fields unrelated to producing fractures. This is not presently done in the geothermal industry.

Breakout analysis has the potential as a valuable tool in siting and completing geothermal wells. It should become a routine practice.

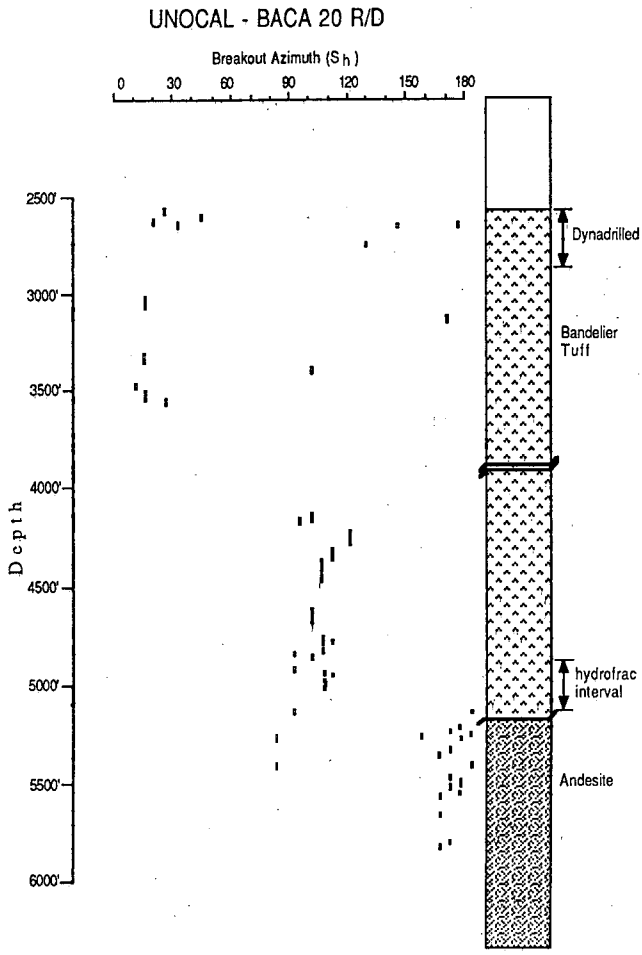


Figure 10. Breakout azimuths in well Unocal 20 R/D, Baca, as a function of depth. See Figure 2 and 7 for full description. Breakouts from first log run, prior to hydrofrac.

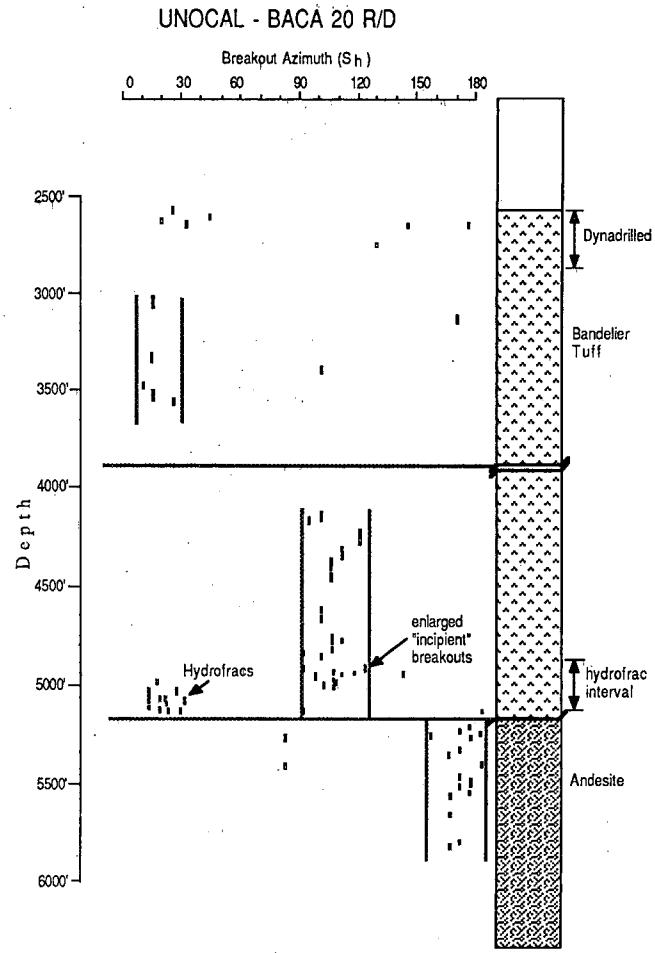


Figure 11. Unocal 20 R/D breakouts from second log run, after hydrofrac. Hydrofractures are evident as are breakouts enlarged from small borehole elongations ignored in first log run. Elongations of 0.2 inches thus are significant. Hydrofractures are 90° to breakout as predicted by theory.

REFERENCES

1. Babcock, E. A., "Measurement of Subsurface Fractures from Dipmeter Logs", Amer. Assoc. of Petrol. Geol. Bull., v. 62 (July, 1978), p. 1111-1126.

2. Ross, H. P., Nielson, D. L., and Moore, J. N., "Roosevelt Hot Springs Geothermal system, Utah - Case Study", Am. Assoc. Petr. Geol. Bull, v. 66 (July, 1982), p. 879-902.

3. Yousas, M. R., and R. L. Bruhn, "Structural fabric and in-situ stress analyses of the Roosevelt Hot Springs KGRA", DOE/ETZ report, Contract DE-AC07-78ET28392, Univ. of Utah, Dept. of Geol. & Geophys., Salt Lake City, 1979, 62 p.

4. Ross, H. P. , and J. N. Moore, "Geophysical Investigations of the Cove Ft.-Suphurdale geothermal system Utah", Geophysics, V. 50, 1985, p. 1732-1745.

5. Arabasz, W. J., and D. R. Julander, "Geometry of Seismically active faults and crustal deformation within the Basin and Range-Colorado Plateau transition in Utah", Geol. Soc. of Amer. Spec. Paper 208, 1986, p. 43-74.

ILLITE AND ILLITE/SMECTITE USES IN GEOTHERMAL SYSTEMS

Judith M. Ballantyne

Earth Science Laboratory, University of Utah Research Institute,
391 Chipeta Way, Suite C, Salt Lake City, UT 84108

The composition of illite is partly dependent on the temperature at which it forms. Modeling of geothermal illites as smectite-muscovite solid solutions has resulted in the development of a new chemical geothermometer that is potentially useful in the temperature range 200° to 300° C (Ballantyne and Moore, 1988). The calculated smectite content of illite appears to be a reasonable predictor of temperature, at least for the published data available. Because of the exchangeability of interlayer cations in smectite and the general non-reversibility of the smectite to illite reaction, use of the illite geothermometer may be restricted to systems in which the associated aqueous chemistry conforms to the Na-K-Ca geothermometer. Thus illites in sedimentary basin systems, and in waning or fossil hydrothermal systems subjected to subsequent, non-illitizing fluids, may not fit the model.

Because temperature is not the only factor affecting illite formation, it is necessary to quantify the effects of other factors. Chemical environment, and whether or not the illite fills fractures or replaces a precursor mineral, also affect the composition of the illite formed. New studies to refine the use of the illite geothermometer are underway at UURI.

Understanding of the mechanism of illite formation is necessary before the geothermometer can be used quantitatively to determine temperatures of formation. A new theory for the mechanism of illite/smectite and illite formation has been developed at UURI.

Predictions of a four-part mechanism for smectite illitization are born out by published data from diverse sources. The four parts of the mechanism are: Ia. Dissolution of smectite layers at layer terminations, initiated by the breaking of Mg-O bonds. Ib. Formation of paired illite layers by dehydration of K^{+} ions, driven by conservation of Al^{3+} from the dissolved smectite layers. II. Precipitation of lath-like or filamentous illite at the margins of illite/smectite platelets, by deposition of products from the dissolution of internal smectite layers. The location of lath growth is controlled in part by the position of channelways provided by edge dislocations within the crystal, along which dissolution products are transported. III. Sealing together of paired illite layers into a massive illite structure, by replacement of exchangeable cations on the outer faces of the pairs by K^{+}. IV. Solid phase rearrangements of ions into a muscovite-like structure.

Illite and I/S can also be formed by other mechanisms, not requiring a smectite precursor. These include replacement of other minerals, and precipitation from solution.

Predictions of the theory are validated by published information in the areas of electron imaging (SEM and TEM), XRD, chemical composition, ^{29}Si NMR analysis, geothermal fluid composition, hydrothermal experiments and kinetics. New thermodynamic models for illite/smectite are indicated. This theory provides a framework for understanding the geological occurrence of both illite/smectite and illite, and for developing new exploration and industrial uses of these minerals.

REFERENCE

Ballantyne, Judith M. and Moore, Joseph N., 1988, A new illite geothermometer: Proceedings of the Thirteenth Stanford Reservoir Engineering Workshop, January, 1988, Stanford, California.

Use of Fluid Inclusion Studies in Geothermal Exploration and Reservoir Characterization

Joseph N. Moore and Michael C. Adams

University of Utah Research Institute, 391 Chipeta Way, Suite C, Salt Lake City, UT 84108

ABSTRACT

A hydrologic model of a geothermal system must include data on the location and characteristics of the reservoir fluids, how these fluids interact, where boiling and mixing occur, and the velocity and direction of fluid movement through the reservoir. These data are vital as input to models that predict the behavior of a geothermal system, and to the placement of production and injection wells.

Fluid inclusions are common in many geothermally deposited minerals and can be an important source of information on the chemical and physical properties of the reservoir fluids. Microthermometic measurements combined with routine petrographic observations can be used to determine the formation temperatures, salinities, and gas contents of the fluid inclusions. These data can be interpreted with respect to boiling, mixing, conductive cooling and steam heating by applying methods analogous to those used in the interpretation of fluid analyses. In this paper we briefly review the applications of fluid inclusion studies to geothermal exploration and development and provide examples of the work currently in progress at the University of Utah Research Institute.

INTRODUCTION

Fluid inclusions are micron-sized cavities formed during mineral growth or fracturing. These cavities are filled with liquid, gas, or a combination of both. Despite their small size, fluid inclusions can be readily heated and frozen until a phase change occurs among the inclusion components. From the temperatures of the phase changes, the formation temperatures, salinities, and gas contents of the fluid inclusions can be inferred. Fluid inclusions are common in many of the secondary minerals found in geothermal systems (e.g. quartz, calcite, anhydrite, sphalerite). Thus, fluid inclusions can be an important source of information on a geothermal system, particularly with respect to the preproduction characteristics of the reservoir. In this paper we briefly discuss some of the ongoing studies being conducted at UURI on fluid inclusions from geothermal systems. These studies include cooperative research efforts with the field operators at Coso, East Mesa, Heber, and Los Azufres as well as investigations to better characterize the compositions of the inclusions through laboratory methods. The overall objective of this work is to develop better hydrogeochemical models of fracture-dominated geothermal systems.

The fluid inclusion measurements discussed in this paper were made on doubly polished plates of the host mineral using a commercially available heating-freezing stage fitted to a microscope. An inclusion can be heated until either the liquid or the vapor phase disappears. This temperature, termed the homogenization temperature, provides an estimate of the temperature of formation. The salinity of the fluid in the inclusion is determined by freezing measurements. The most important low-temperature phase changes observed in fluid inclusions are the final ice melting temperature (Tm), from which the salinity as equivalent weight percent NaCl is calculated, and the melting of CO_2 clathrate. This latter phase is indicative of CO_2-enriched fluids.

DETERMINATION OF THERMAL PROFILES

Fluid inclusions provide a relatively simple means of establishing what the temperature distributions were prior to drilling. Such data are especially useful when information is needed before the wellbore temperatures have stabilized or where casing failure allows colder water to enter the well. Figure 1 illustrates the degree of correspondence that can be achieved between fluid inclusion homogenization temperatures and downhole mea- surements. The fluid inclusions that were studied in this well were found in vein quartz and calcite. These veins appear from textural evidence to represent the youngest thermal event within these rocks. In most of these veins, the quartz occurs as a narrow rim along the vein walls whereas the calcite

occurs as coarse crystals within the vein interiors. The lack of quartz-calcite intergrowths in most samples suggests that calcite deposition resulted from heating or mixing.

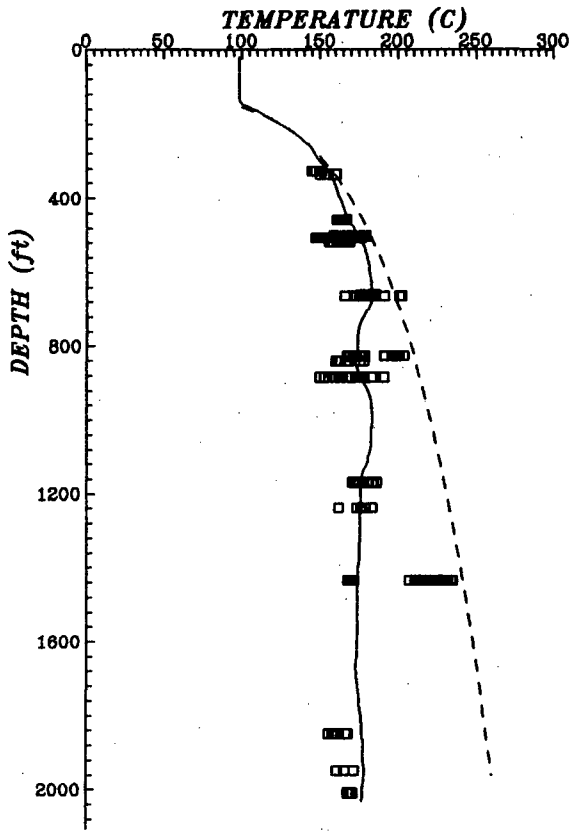


Fig. 1. Comparison of fluid inclusion and measured temperatures from a shallow corehole. Each square represents a fluid inclusion homogenization temperature. The solid line is the present measured temperature. The dashed line is the boiling point curve calculated for a water table at a depth of 200 feet (61m).

In contrast, veins sampled at 661 and 840 feet (201 and 256 meters respectively) consist of intergrown calcite and quartz, indicating that boiling occurred locally during the deposition of the veins at these depths. While such textures can be interpreted in terms of processes affecting the fluids, they provide no insight into the composition or temperature of the fluid.

The close correspondence between the fluid inclusion and measured temperatures indicates that the calcite veins were deposited by the present geothermal system and that these veins can be used to map temperature and salinity variations in three dimensions. In addition, the fluid inclusion homogenization temperatures can provide information on changes in temperature with time. For example, in the lower portion of the corehole, the higher measured temperatures relative to those recorded by the fluid inclusions indicate that some heating of the rocks has occurred since deposition of the veins.

RESERVOIR PROCESSES

By converting homogenization temperatures to enthalpy and the freezing point depressions of the fluids to equivalent weight percent NaCl (Potter et al., 1978), enthalpy-salinity plots analogous to those used for fluid analyses (Fournier, 1979) can be constructed. Figure 2 is an enthalpy-salinity plot for the inclusions shown in Figure 1. The data define a straight line that can be interpreted in terms of mixing between two end members; a low-salinity heated groundwater, with a temperature of 166°C, and a higher salinity geothermal fluid. The relatively high temperature and low salinity of the diluting fluid, combined with the high CO_2 contents of fluid inclusions from similar depths in other wells in the same system suggest that the high-salinity geothermal fluids are being diluted by a steam-heated groundwater.

As part of a study of the Salton Sea geothermal system, Moore and Adams (1988) used salinity-temperature relationships to distinguish the thermal cap in two wells from the underlying reservoir. The thermal cap in these wells was found to consist of evaporites, lacustrine deposits, and anhydrite- and calcite-cemented sandstones. This work suggested that growth of the cap occurred as conductively heated, high-salinity brines that formed in the shallow parts of the geothermal system percolated downward. Homogenization temperatures were found to increase rapidly with depth through the thermal cap, yielding an average gradient of .66°C/m between the surface and 330 m. In contrast, homogenization temperatures from the underlying reservoir rocks were found to vary little with depth.

ESTIMATION OF GAS CONTENTS

Carbon dioxide and other gases are important in many geothermal systems and their presence may significantly affect the freezing point depressions of the fluid inclusions (Hedenquist and Henley, 1985). Figure 3 shows the expected relationships between homogenization and ice melting temperatures for gas-rich fluid inclusions. The primary effect of boiling is to remove the noncondensable gases from the fluids. The difference in the freezing point depressions of

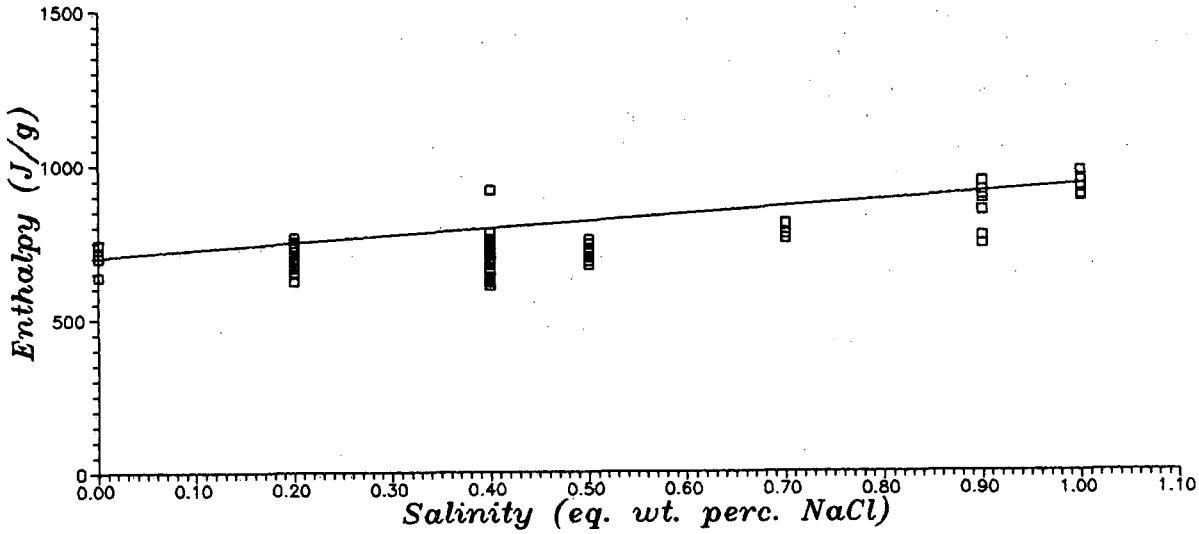


Fig. 2. Enthalpy - salinity relationships for the fluid inclusions shown in Figure 1. Each square represents one inclusion. The straight line represents a dilution trend between the high and low salinity fluids.

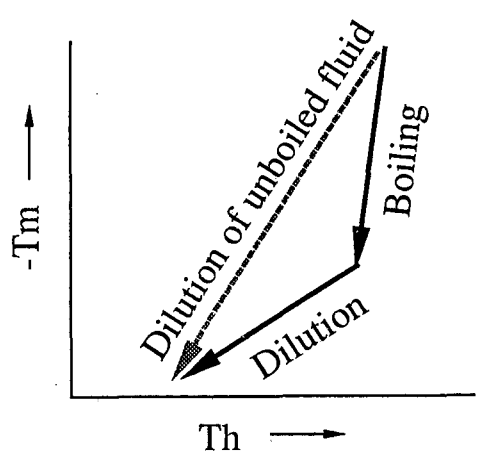


Fig. 3. Expected trends in ice melting (Tm) and homogenization (Th) temperatures resulting from boiling and dilution of a fluid with a high initial gas content (from Hedenquist and Henley, 1985).

inclusions trapped before and after boiling can be related to the gas content of the fluid through the relationship:

$$\text{delta Tm} = 1.86\ \text{Em} \qquad (1)$$

where delta Tm is the difference between the highest and lowest ice-melting temperature of the inclusions, and Em is the molality of CO_2 in the inclusion (Hedenquist and Henley, 1985). Figure 4 provides a good example of the effect of gas loss on the freezing point depression of fluid inclusions from a deep well located in the northeastern part of the Los Azufres geothermal system. The samples are from a depth of 798-804 m. Both liquid- and gas-rich inclusions are found in these samples, indicating that boiling has occurred. The gas content of these inclusions calculated from equation 1 is 3.0 weight percent, a value that is consistent with the estimated gas content of the Los Azufres fluids.

CHEMISTRY OF FLUID INCLUSIONS

Because of the large number of components in the geothermal fluids, microthermometric measurements can only provide an approximation of the fluid chemistry. More detailed compositional information requires direct analysis of the inclusions either through the use of various microanalytical techniques or the analysis of the fluids extracted from large numbers of inclusions (Shepherd et al., 1985). Because of the narrow compositional range displayed by most of the samples we have studied, and the

small size of the inclusions, chemical analyses of the bulk fluids are most suitable. We are currently investigating the use of ICAP spectrometry to directly determine the composition of the fluids released during the decrepitation of inclusion-rich samples.

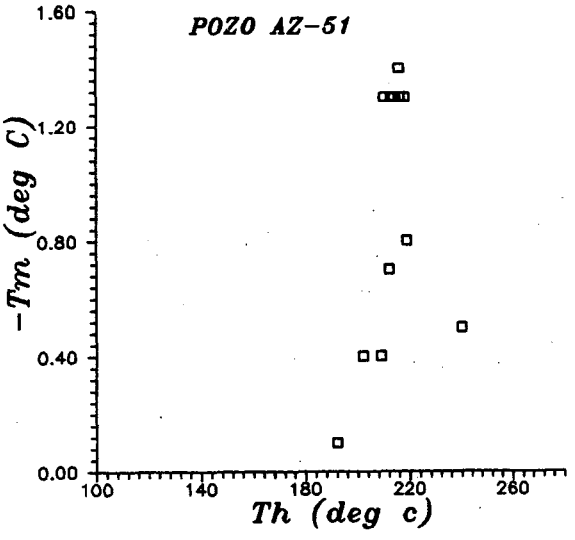


Fig. 4. Ice melting (Tm) and homogenization (Th) temperatures of inclusions in quartz and calcite from Los Azufres well AZ-51.

CONCLUSIONS

Detailed hydrogeochemical models are necessary to predict the behavior of a geothermal system during production. Because of the drilling and completion techniques currently in use, fluid samples obtained from geothermal wells generally cannot yield the detail needed to construct these models. The results of our investigations demonstrate that measurements made on fluid inclusions can greatly increase the amount of geochemical and thermal data obtained from the borehole. Additional studies of well documented geothermal reservoirs and the development of analytical techniques to determine the chemistry of the inclusions are still needed.

ACKNOWLEDGEMENTS

Funding for this research was provided by the U. S. Department of Energy under contract DE-AC07-85ID12489. Beverly Miller prepared the samples and performed some of the measurements.

REFERENCES

1) Fournier, R. O., 1979, Geochemical and hydrologic considerations and the use of enthalpy-chloride diagrams in the prediction of underground conditions in hot-spring systems: Journal of Volcanology and Geothermal Research, v.5, p. 1-16.

2) Hedenquist J. W., and Henley, R. W.,1985, Effect of CO_2 on freezing point depression measurements of fluid inclusions - evidence from active systems and implications for epithermal mineralization: Economic Geology, v. 80, p. 1379- 1406.

3) Moore, J. N., and Adams M. C., 1988, Evolution of the thermal cap in two wells from the Salton Sea geothermal system, California: Geothermics, in press.

4) Potter, R. W., II, Clynne, M. A., and Brown, D. L., 1978, Freezing point depression of aqueous sodium chloride solutions: Economic Geology, v. 73, p.284-285.

5) Shepard, T., Rankin, A. H., and Alderton, D. H. M., 1985, A pratical guide to fluid inclusion studies: Blackie and Son Ltd., Glasgow, England.

THE PREDICTION OF CHEMICAL SCALING IN GEOTHERMAL POWER OPERATIONS

John H. Weare and Nancy E. Møller
University of California, San Diego

Abstract

The purpose of the DOE program at UCSD is to provide a highly reliable thermodynamic model of brine chemistry for use by the geothermal community. This model will be of sufficient accuracy to be used for the prediction of chemical problems in production, energy extraction, and brine reinjection. By replacing and extending costly laboratory simulations, the model will provide a cost effective design tool to enhance the efficiency of geothermal operations.

Recent emphasis has been placed on modeling the deposition of the scale-forming minerals, calcite ($CaCO_3$), calcium sulfate ($CaSO_4$), and amorphous silica (SiO_2). At present, the scaling model has the capability to calculate gypsum-anhydrite, amorphous silica and calcite solubility as a function of partial pressure of CO_2 and brine composition for a range of temperatures to 250°C. We also now have the capability of calculating breakout (onset of two phase flow) for a limited set of temperatures.

In the following article, we use the model to treat several examples of scaling and breakout in geothermal production systems. For example, we predict from well head concentration data for a Dixie Valley well that 2.328×10^4 kg of calcite scale will precipitate in the well bore in one year of operation. These results demonstrate that important information about the design and operation of a geothermal power production system can be obtained from model simulation.

Introduction

Interest in the utilization of geothermal energy continues to grow. However, with this growth there is an increasing awareness of the chemical problems which can hinder the efficient extraction of energy. While the chemistry of geothermal brines has received less attention than other aspects of geothermal operations, problems with the chemistry often limit or completely restrict the exploitation of the resource. Similar problems occur in the petroleum industry; however, they may be less damaging to the utilization of the resource. For example, well damage due to scale formation in oil wells necessitates some down-time to clean up well bores. This is inconvenient but endurable because of the potentially high amount of oil energy extractable per brine volume. On the other hand, scaling in geothermal operations can be of such magnitude as to render them infeasible. This is because of the relatively smaller amount of energy available per volume from geothermal brines and the much greater amounts of brine handled during the energy extraction process.

Chemical problems can be experienced in all phases of geothermal plant operation. Removing brine for energy extraction can cause porosity changes in the formation which result in scaling of the well, thus making it difficult to produce enough brine for continued operation. Chemical incompatibilities encountered during reinjection of waste brines which are out of equilibrium with the receiving formation and formation brine may lead to plugging of the formation. Significant mineral precipitation in power plant equipment is also common. As an example, figure (1) shows a section of pipe, taken from a geothermal power plant in the Imperial Valley, which is almost completely plugged with calcite scale. The costly effects of such pipe scalings have been well documented.

It is important to be able to evaluate the possible effects of brine chemistry on geothermal plant operation for a specified range of conditions in order to assess and enhance the economic value of the resource. Given this capability, proper choices can be made so that chemical problems such as the scale formation illustrated in figure (1) can be avoided or diminished. Such a capability would also allow design criteria to be established for the successful exploitation of a resource. Moreover, it would allow the potential of a possible resource to be evaluated under specified site conditions before substantial investment is made.

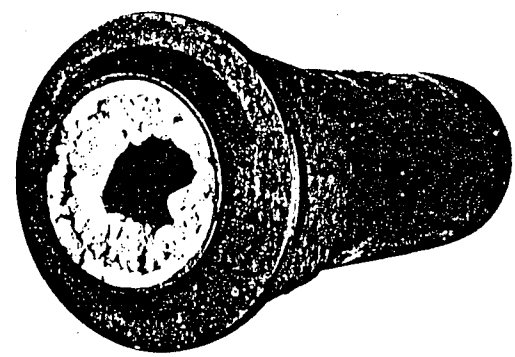


Figure (1)
Calcite scale in a pipe from a geothermal power plant.

In our program at UCSD, we are developing models of brine chemistry which will be used to predict the problems encountered when brines are utilized for the production of geothermal power. Traditionally such problems have been identified either from actual plant production experience or from laboratory simulations. The models we are developing greatly facilitate the identification of such problems, the development of strategies for their solution and the testing of these operational approaches. The models are easily and inexpensively applied to the wide variety of chemical problems that are encountered in geothermals operations. In addition to being a valuable and inexpensive aid to laboratory simulations, these models can provide information about the process chemistry under conditions which are difficult to simulate in the laboratory (e.g., high temperature and pressure environments). In table (1), we summarize some of the ways our chemical models of geothermal brines may be used to optimize geothermal operations.

In prior reports and publications we have given detailed descriptions of our model equations and parameterization procedures (see, for example, Weare, 1987). This article, after a brief description of the model in section (2), will emphasize the application of the model to scaling problems which are common to geothermal plant operation. These applications include discussions of the chemical controls governing the formation of the important scaling minerals, amorphous silica (section (3)) and calcite (sections (4) and (5)).

As is graphically illustrated in figure (1), calcite scale formation frequently plays a role limiting the economic value of geothermal power plant operations. Such chemical problems are particularly difficult to predict because of the relation of the gas phase composition and pressure to the solubility of the scale forming minerals. Because of this relationship, it is critical in plant design to identify conditions under which the working brine will become a two phase system (flash or breakout). In section (4) we discuss the prediction of breakout in geothermal brines from our model. Our results show excellent agreement between on site measurements and the brine breakout predicted by the models.

In designing power plants it is important to have an accurate estimate of the down hole composition of the geothermal fluid. Unfortunately, down hole samples are rarely available because of technical difficulties. Surface samples, on the other hand, may not accurately reflect the down hole composition because the scale forming minerals may have precipitated out of the brine when it was produced. In section (5) we discuss the application of the models to reconstructing down hole

brine compositions from surface sample measurements. In the process of reconstructing this composition, potential problems due to brine scaling can be identified.

Table 1

USES OF A BRINE SIMULATION MODEL	
Exploration	• Scale Prediction • Formation Water Characterization • Simulation of Chemical Treatments
Plant Design and Operation	• Scale Formation • Energy Recovery Prediction • Prediction of Gas Breakout
Waste Treatment	• Simulation of Mineral Recovery • Prediction of Environmental Hazards • Simulation of Reinjection Strategies

Overview of the Model

In order to predict scale formation from the composition of the working fluid, it is necessary to build a highly accurate model of the thermochemical behavior of the geothermal brine. The solubility of a mineral which produces scale is determined by the interactions of the dissolved solutes composing the solid with the other principal solutes in the aqueous phase. For example, the solubility of the scale forming mineral, amorphous silica, in a concentrated NaCl brine is a function of the interaction between the dissolved SiO_2 species and the dissolved Na^+ and Cl^- ions. Our models focus on the accurate description of these interactions. Recently this work has been reviewed (Weare, 1987).

The model begins with the expression for the free energy, G, of the system:

$$G = \sum_i n_i \mu_i, \tag{1}$$

Where the summation i is over all solution species and solid phases. This function, if minimized subject to mass balance constraints, gives the amounts of each aqueous species and of the solid phases. Generally, the chemical potentials, μ_i, in equation (1) are further defined in terms of the activity coefficients, γ_i, and concentration m_i of the individual species i in solution by the relation:

$$\mu_i = \mu_i^o + RT \ln m_i + RT \ln \gamma_i^{elec} + RT \ln \gamma_i^{exc}. \tag{2}$$

The first term on the right hand side of equation (2) is the standard chemical potential. For a pure mineral, this term is the only term needed. For a solution phase species, the three additional terms are necessary. The second term, where m_i is the molality of species i, describes ideal mixing. The third term represents nonideal corrections for long range electrostatic forces and is usually given in terms of the Debye-Hückel activity formula, and the fourth term represents additional (excess) nonideal corrections for highly concentrated brines. As very little is known about concentrated brines, the fourth term must be given in terms of a phenomenological expression, which contains parameters evaluated from experimental data.

Two steps are required to define a model describing brine chemistry. First, the species in solution which appear in equation (1) must be specified. For most geothermal applications, the species in solution are well known (e.g., Na^+, Cl^-, HCO_3^-, etc.). And second, an expression must be given for the fourth term in equation (2). In the models we have been developing, this term is given by the expressions of Pitzer and coworkers (Pitzer, 1987). This approach appears to have the accuracy required while introducing a minimum number of parameters to be evaluated from experimental data. In this approach, the fourth term is represented in the virial expansion form:

$$RT \ln \gamma_i^{exc} = \sum_j B_{ij}(I) m_j + \sum_{jk} C_{ijk} m_j m_k \ldots\ldots \tag{3}$$

In the first term on the right hand side of equation (3), the coefficient, B_{ij}, is a function of ionic strength (see Pitzer, 1987) containing parameters which must be established from experimental data. The constant coefficient, C_{ijk}, in the second term on the right hand side also is evaluated from experimental data. The procedure for evaluating the required parameters has been discussed in detail in Weare (1987). For most systems of interest to the geothermal community, all the required parameters may be obtained from binary (e.g., $NaCl-H_2O$) and ternary (e.g., $NaCl-CaCl_2-H_2O$) experimental data. The high accuracy of our models, parameterized by these relatively simple data, in applications to very complex systems has been documented in a number of published articles (see Harvie, Møller and Weare, 1984). In the remainder of this article, we will focus on the application of our models to investigate various problems encountered in the geothermal industry.

Control of Silica Scale Formation

Scale formation in plant equipment and porosity losses in injection well formations created by the precipitation of amorphous silica have been identified as important problems in the operation of geothermal power plants. The formation water in high temperature hydrothermal systems is usually in near equilibrium with the SiO_2 mineral, quartz. The solubility of quartz below the critical temperature of water is a monotonically increasing function of temperature. Therefore, when hydrothermal brine is produced from a formation and the energy extracted in the geothermal power plant, it would be expected that quartz would precipitate from the cooled brine. Fortunately, however, quartz rarely precipitates because of the slow kinetics involved in this reaction. The more common precipitation product is amorphous silica. At a given temperature, amorphous silica is considerably more soluble than quartz. Its solubility is also an increasing function of temperature. Therefore a brine initially saturated with respect to quartz would not be expected to precipitate any SiO_2 until it reaches saturation with respect to amorphous silica at a considerably lower temperature.

This effect provides a strategy for avoiding silica scaling problems. If a brine is extracted from a formation saturated with respect to quartz at temperature, T_{in}, and if the operating temperature of the power plant is not allowed to decrease below the temperature, T_o, at which amorphous silica will precipitate, then silica scale formation should not be a problem. The difference between the temperatures T_{in} and T_o represents the range of outlet temperatures at which the plant may be operated without scale formation. In the following, we show how the model may be used to calculate the temperature T_o.

The data of Chen and Marshall (1982) were used to evaluate the silica interaction parameters in the appropriate expression for term four in equation (2). The results of this data fitting are given in figure (2) for two of the required subsystems. When all the subsystems have been parameterized from experimental data over an appropriate temperature range, a variable temperature model of amorphous silica solubility for brines of general composition can be constructed. This model can then be used to calculate the solubility of amorphous SiO_2 for a given temperature in an arbitrary brine. Such calculations are illustrated for three different brine compositions in figure (3) (for concentrations, see table (2)). If the measured concentration of amorphous silica in the geothermal brine exceeds the equilibrium value calculated for that brine at a given temperature (solid lines, figure (3)), then precipitation may occur at this operating temperature. For example, consider the Heber brine. If the calculated solubility of amorphous silica exceeds .047 (the concentration of SiO_2 measured in the Heber brine), then we would not expect scale formation. From figure (3) we see that this condition is met for the Heber brine for all temperatures above 160°F.

Of course, the consequences of retaining a high outlet temperature can be expensive. In figure (3), we have also calculated the solubility of

SiO_2 in more concentrated brines (Woolsey and Salton Sea) from the Imperial Valley (see table (2)). As can be seen from the figure, SiO_2 is less soluble as the concentration of the solution increases. To operate these wells without silica scale formation requires higher outlet temperatures assuming the same cocentration of SiO_2 in the formation brine. To illustrate the effect of this requirement on the power production of the system, we have calculated the ideal efficiency ($e = \frac{T_{in} - T_{out}}{T_{in}}$) of these brines and have compiled the results in table (3). For the most concentrated brine (Salton Sea) there is a 40% loss of efficiency. Such model calculations may provide valuable information when deciding whether or not to establish a geothermal power plant in a particular area.

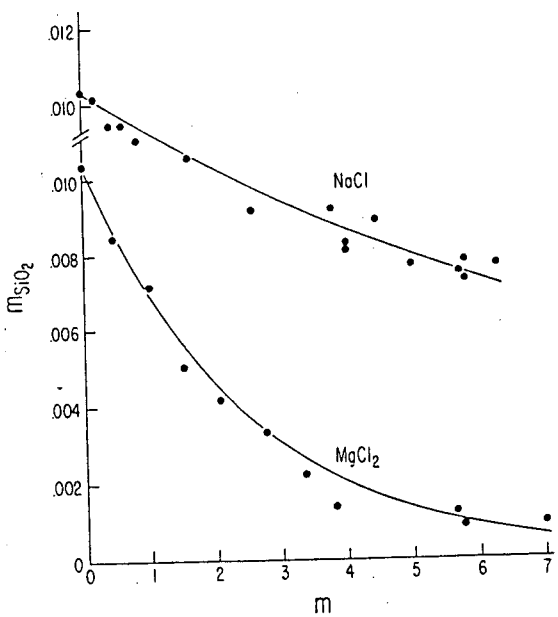


Figure (2)

Solubility of amorphous silica in concentrated brines at 150°C. The solid lines give the model predictions. The points are the data of Chen and Marshall (1982).

Table 2

COMPOSITIONS OF
GEOTHERMAL WELL WATERS

Component	Heber	Woolsey	Salton Sea
Na	.1862	1.3801	2.969
K	.0065	.2015	.606
Mg	.00016	.01086	--
Ca	.0522	.50138	.946
Cl	.2222	3.1917	5.921
SO_4	.00086	--	--

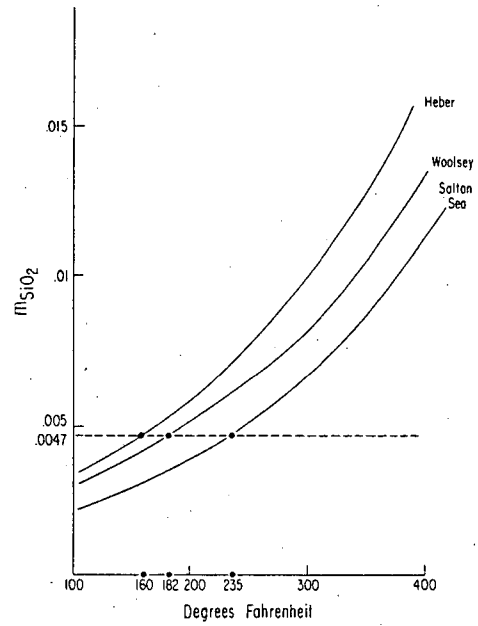


Figure (3)

The predicted solubility of amorphous silica in mixed brines (solid lines). The silica concentration is that of the Heber brine (dashed line).

Table 3

IDEAL EFFICIENCY CHANGES

	Temperature		% Change in Efficiency
	Inlet	Outlet	
Heber	340	162	---
Woolsey	340	180	-10%
Salton Sea	340	235	-41%

Prediction of Breakout

Scale formation from the carbonate mineral, calcite, is a persistent problem in geothermal operations. An illustration of the disastrous effects on power plant equipment of such scale has been given in figure (1). The prediction of carbonate deposition is particularly difficult because of the strong dependence of the solubility of calcite on the concentration of dissolved CO_2. The problem is complicated further by the polyprotic acid/base equilibria in the carbonate system. This means that a complete model of the acid/base equilibria in the solution as well as a model of gas to solution equilibria must be available before meaningful predictions can be made. Our group has made considerable progress with such a model. The details of this work have been discussed elsewhere (see Harvie, Møller and Weare, 1984). In this section and the following, we discuss the application of this work.

The solubility of calcite is a strong function of the solution concentration of CO_2. The solution concentration of CO_2 is in turn a function of the CO_2 pressure above the solution. When a brine forms a bubble (breaks out) and two phase flow begins, the CO_2 concentration in the solution phase drops precipitously. Since calcite is more soluble in high CO_2 solutions, this leads to precipitation of scale if the carbonate system is the principal acid/base system in the brine. For this reason, the onset of two phase behavior in a geothermal operation involving carbonate brines is

important to control.

A brine will break out when the vapor pressure of the brine equals the overburden pressure. When a geothermal well is produced, the overburden pressure may be reduced. This can induce break out which may result in scale formation at some point in the well or power plant.

The vapor pressure of a brine is determined from the pure water vapor pressure corrected for the dissolved solute concentration plus the contribution of the confining pressures of the various dissolved gases in the brine. In a typical carbonate carrying brine, the contribution of the dissolved gases to the total vapor pressure of the brine is apt to be of the order of magnitude of the contribution of the water vapor. Typically, dissolved CO_2 is the most concentrated dissolved gas in a geothermal brine. However, other dissolved gases such as methane, which may appear in lesser concentration, may have a higher escaping tendency than CO_2 and therefore contribute considerably to the breakout pressure.

As an example and test of our model, consider the East Mesa brine, the composition of which is given in table (4). The breakout characteristics of this brine as a function of temperature were measured by Robertus (private communication) and are shown in figure (4). As is typical, these concentrations were measured after breakout and therefore the concentrations prior to breakout had to be reconstructed using the model. The calculated prebreakout concentrations are given in table (5). Using these concentrations, the various contributions to the vapor pressure of the brine as a function of temperature can be computed. The results are summarized in table (6) and are plotted as the Δ in figure (4). The agreement between the calculated breakout and the measured values is within experimental accuracy. Note that for this brine, the contribution to the vapor pressure from dissolved gasses is of the same magnitude as the contribution from water vapor.

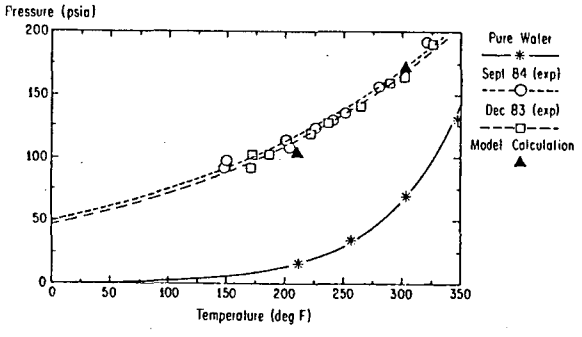


Figure (4)

CO_2 breakout conditions in the Magma plant inlet.

Prediction of Calcite Deposition in Well Bores

Our calcite solubility model may also be used to calculate the amount of calcite deposited when geothermal water is produced from a formation. In the following example, measured well head concentrations for a Dixie Valley well (table 7), supplied by Marshall Reed of DOE, were used to calculate the saturation index, SI, of the brine under various conditions. SI, which is defined as:

$$SI = \left\{ \frac{\prod_i a_i^{\nu_i}}{K_{sp}} \right\}, \qquad (4)$$

gives an estimate of the ability of the brine to precipitate or dissolve calcite. In equation (4), a_i is the activity of solution species i. ν_i is the stoichiometric coefficient of species i in the mineral. K_{sp} is the solubility product of the species composing the mineral of interest. (For example, for calcite, S.I. $= \left\{ \frac{a_{Ca^{++}} a_{CO_3^{--}}}{K_{sp}} \right\}$.) A value of S.I. greater than 1.0 indicates that the brine is supersaturated and can precipitate scale, while a value less than 1.0 indicates that the brine is undersaturated.

Table 4

ANALYTICAL DATA SUPPORTING CO_2 BREAKOUT TESTS

Gas/Liquid Ratio = 0.31 Liters/Kg at 39°C.
Gas Volume also at 39°C.

Anion/Cation Analysis

	mg/l		mg/l
Al	0.0	Cl^-	3449.0
As	0.5	SO_4^-	70.0
B	6.75	HCO_3^-	492.0
Ba	0.80	Tot CO_2	1519 (1738 in Jan.85)
Ca	51.5	pH = 5.71	@43°C
Fe	15.5	15.1 psia	
K	210		
Li	6.60		
Mg	1.80		
Na	2035.0		
Si	103.0		
Sr	11.70		
Cu	1.10		
Mn	0.25		

Anion/Cation Analysis

Components	Mole %
CO_2	72.9
Ar	0.16
O_2	1.13
N_2	9.20
CO	< 0.10
He	< 0.01
H_2	0.27
CH_4	16.3

Table 5

RECONSTRUCTED EAST MESA BRINE COMPOSITION

Component	Concentration (m.)
Na^+	.108
Ca^{+2}	.00135
Cl^-	.102
HCO_3^-	.00848
CO_2	.03169

The calculated solution compositions using the water concentrations given in table (7) are summarized in table (8). The first row contains calculated values for the separated brine (flashed brine) calculated from the separated brine concentration (table (7), column I). As indicated in table (8), row 1, the SI for this brine is supersaturated with respect to calcite, indicating that some calcite precipitation may have occurred. Generally, complete equilibrium is not obtained in a flashing system. In the second row, the concentrations used were those calculated when the gas phase was incorporated in the separated brine (column II, table (7)). As expected, because of the increase in dissolved CO_2, the brine is now undersaturated with respect to calcite.

There are two explanations of the undersaturation (low value of Ca and CO_3 in the brine) of the well head water when brought back to forma-

Table 6

CONTRIBUTIONS TO BREAKOUT PRESSURE

Temperature (°C)	P_{CH_4} atm.	P_{CO_2} atm.	P_{H_2O} atm.
150.	26.	77.	69.
200.	16.	72.	225.

tion conditions by theoretically incorporating the outgassed CO_2. Either calcite was not present in the formation and therefore the brine did not reach saturation, or calcite precipitated when the brine flashed. In the latter case, calcite has been deposited in the well bore. When the CO_2 and other gasses are reincorporated in the brine for purposes of calculation (column II, table (7)), this lost calcite is not included. We can estimate the amount of scale deposited by using the model to reequilibrate the reconstructed formation brine with calcite. The results of such a calculation are given as row 3, table (8). Subtracting the Ca concentration in row 2 of table (8) from the value in row 3 of the table gives the amount of Ca ($.97 \times 10^{-5}$ mole) deposited per kilogram of water produced from this formation. According to Reed's measurements, 2.4×10^9 kg of brine would be produced from this well per year. Therefore 2.328×10^4 kg of scale would be deposited in the well bores in one year of operation.

Table 7

COMPOSTION OF WELL HEAD WATER
DIXIE VALLEY [a]

	I[b]	II[c]
Na	0.01143	0.01143
Ca	0.0000178	0.0000178
Cl	0.00777	0.00777
HCO_3	0.00329	0.00329
CO_3	0.000203	0.000203
CO_2	0.0	0.0516

[a] Brine compositions from Marshall Reed.
[b] Brine composition after flash.
[c] Brine composition with CO_2 reintroduced.

Table 8

SATURATION CALCULATIONS
FROM THE DATA OF REED

Case	CO_2	HCO_3	CO_3	Ca	P_{CO_2}	pH	SI
1[a].	.000902 m.	.00256 m.	.000036 m.	.0000178 m.	0.090 m.	8.1 m.	2.3 m.
2[b].	.0514	.00365	.0000053	.0000178	5.1	6.5	0.65
3[c].	.0514	.00368	.0000078	.0000275	5.1	6.5	1.0

[a] Calculated using composition I, table 7.
[b] Calculated using composition II, table 7 calcite not allowed to dissolve.
[c] Calculated using composition II, table 7 calcite allowed to dissolve.

The accuracy of the model for calculations such as those in the last example could be tested if both downhole and well head samples were available. Unfortunately, such samples are difficult to find. An alternative is to test the model against laboratory simulations of down hole conditions as reported by Shaughnessy and Kline (1982). In these simulations, which were done to analyze oil well damage from scale formation, surface brine samples were re-equilibrated with formation rocks in an autoclave at 100°C. Our model can be used to compute the amount of Ca under simulated formation conditions. The results of the model calculations are compared to the laboratory data in table (9). As can be seen from the table, the predictions of the model are in excellent agreement with the Shaughnessy and Kline (1982) laboratory simulation. These results support the calculations given in the prior paragraph suggesting that our calculations using the Dixie Valley data are correct.

Table 9

MODEL CALCULATION OF CALCITE
SOLUBILITY IN HIGHLY PRESSURED
FORMATION WATERS AT 100°C

	Equilibrium composition of surface brine	Composition of surface brine re-equilibrated to formation conditions (calcite present) P_{CO_2} = 34 atm. EXPERIMENT	Composition of surface brine re-equilibrated to formation conditions (calcite present) P_{CO_2} = 34 atm. MODEL CALCULATION
Na^+	.331 m.	.331 m.	.331 m.
Cl^-	.301	.301	.301
Ca^{+2}	.00042	.006	.00567
HCO_3^-	.030	.042	.043

Acknowledgements

It is a pleasure to acknowledge many discussions with Marshall Reed (DOE), Don Shannon (Battelle) and Bob Robertus (Battelle).

References

Chen, C.-T.A. and Marshall, W.L. (1982). Amorphous silica solubilities IV: Behavior in pure water and aqueous sodium chloride, sodium sulfate, magnesium chloride and magnesium sulfate solutions up to 350°C. *Geochim. Cosmochim. Acta* **46**, 279-287.

Harvie, C.E., Møller, N. and Weare, J.H. (1984). The prediction of mineral solubilities in natural waters: The Na–K–Mg–Ca–H–Cl–SO_4 –OH–HCO_3–CO_3–CO_2–H_2O system to high ionic strength at 25°C. *Geochim. Cosmochim. Acta* **48**, 723-751.

Pitzer, K.S. (1987). A thermodynamic model for aqueous solutions of liquid-like density. *Rev. in Mineralogy* **17**, 97-142.

Robertus, R. (1985). Private Communication. Battelle Pacific Northwest Laboratories.

Shaughnessy, C.M. and Kline, W.E. (Sept. 1982). EDTA removes formation damage at Prudhoe Bay. Soc. of Petrol. Eng., 57th Annual Fall Technical Conference. *SPE 11188*.

Weare, J.H. (1987). Models of mineral solubility in concentrated brines with application to field observations. *Rev. in Mineralogy* **17**, 143-176.

GEOCHEMISTRY IN GEOTHERMAL RESERVOIR TECHNOLOGY

Alfred H. Truesdell
U.S. Geological Survey, Menlo Park, CA

ABSTRACT

Geochemistry of fluids and solids has an important role in geothermal reservoir technology. The use of fluid chemistry in exploration is well established; its use in reservoir studies is an expanding field. During exploration the chemistry, temperature, and flow of surface hot springs and fumaroles can be used to estimate subsurface temperatures, convective heat flow, directions of subsurface fluid flow, chemistry and state (vapor or liquid) of subsurface fluids, and the origin of recharging water. In subsequent exploratory drilling, the character of drill cuttings and the chemistry and temperature of well fluids are used to confirm or revise earlier interpretations and extrapolate deeper into the reservoir. At this stage, the homogeneity of reservoir fluids, the relation of fluid and rock compositions, and the nature of natural reservoir processes (boiling, dilution) can be studied. During power production, monitoring fluid chemistry provides warning of processes (boiling and mineral deposition in the aquifer, inflow of cold water) that may adversely affect well (and field) performance. Some new methods of interpretation of geochemical data are discussed using Cerro Prieto as an example. A short bibliography of recent papers is included to draw attention to other geochemical studies not discussed here.

INTRODUCTION

The Cerro Prieto geothermal field, located 20 miles southeast of Mexicali in Baja California, Mexico, is the world's largest producing hot-water geothermal field with a capacity of 620 MWe (fig. 1). Since before the start of production in 1973, the Comision Federal de Electricidad (CFE) has collected and analyzed produced brine, and since 1977 the U.S. Geological Survey (USGS) has collected and analyzed brine and steam for isotopes and gases. This large body of data along with wellhead physical data (there are now over 70 producing wells) has been used to indicate reservoir processes as well as temperatures, origin of constituents, and other chemical properties. Of most practical interest to reservoir engineers are the geochemical methods of monitoring changes in fluid character and reservoir processes caused by fluid production. The CFE and USGS chemical and isotopic data show fieldwide processes of cold-water influx and boiling induced by drawdown and identify upflow areas and field margins. At the same time, detailed study of the changes in fluid chemistry with time of single wells show details of local processes of boiling and heat transfer, mixing with steam or cooler water, and migration of fluids within the reservoir.

FIELDWIDE CHANGES

Studies by CFE (Manon et al., 1979; Fausto et al., 1979, 1981) used Na-K-Ca geothermometry and concentration patterns to indicate changes in fluid temperature and composition due to exploitation. From 1973 to 1977 they found decreases in temperature of 10-20°C and in chloride of 370-670 ppm per year. The margins of the field to the south and west were indicated by chloride dropoff but the eastern margin was not defined. Changes in chloride (Truesdell et al., 1979a and unpublished data) and isotopes (Truesdell et al., 1979b; Stallard et al., 1987) show similar patterns (fig. 2), with lower chloride and lighter isotopes at the field margins, and also show drawdown of more dilute, isotopically lighter water in the center of the field along fault L (fig. 1) located by Halfman et al. (1984). This drawdown has increased from 1977 to the present. Cold waters are also entering the field from the southeast and probably the west, although interpretation of western inflow is complicated by lack of wells and close proximity to the central drawdown. A zone of upflow in the northeastern part of the field is indicated in recent isotope surveys by isotopically heavier fluids (fig. 2).

RESERVOIR PROCESSES NEAR INDIVIDUAL WELLS

Geothermometers differ in their rate of equilibration and these differences may be used to indicate processes that have heated or cooled fluids during their passage to the well. The Na-K-Ca geothermometer (T_{NKC}), which equilibrates relatively slowly in fluids of moderate or high salinity, indicates fluid temperature away from the influence of the well; and the quartz saturation geothermometer (T_{SIL}), which equilibrates relatively quickly, indicates well-bottom temperature. These temperatures along with the "enthalpy temperature" (T_E, the calculated temperature of liquid having the same enthalpy as the measured total fluid enthalpy) give clear indications of near-well reservoir processes. Many of the following cases have been observed at Cerro Prieto and Ahuachapan (El Salvador): $T_{NKC} = T_{SIL} = T_E$ indicates all-liquid, fully equilibrated fluid; $T_E > T_{NKC} > T_{SIL}$ results from near-well boiling with fluid cooling and transfer of heat from rocks (fig. 3 shows exponential enthalpy decline characteristic of near-well boiling with a constant pressure boundary); $T_E = T_{NKC} > T_{SIL}$ results when near-well boiling continues but rock and fluids equilibrate thermally; $T_{NKC} > T_{SIL} = T_E$ results from mixing near the well with cooler liquid and subsequent reequilibration of silica; $T_E > T_{NKC} = T_{SIL}$ results from mixing of steam with equilibrated liquid in or near the well; $T_{NKC} > T_{SIL} > T_E$ results from mixing of cooler water in the well with lowering of T_E and apparent lowering

of T_{SIL} due to dilution; $T_{SIL} > T_{NKC}$ results from sweep of cooler water through hotter rock (fig. 4); and $T_{NKC} = T_{SIL} > T_E$ results from conductive cooling in the wellbore during reduced flow. These processes may be combined such as boiling in the reservoir and mixing with cooler water in the well. Changes in calculated aquifer chloride indicate processes of concentration and dilution (fig. 5). Mineral deposition and formation plugging that results from localized aquifer boiling (Truesdell et al., 1984), and the "cold sweep" of cooler water heated by reservoir rock in the first-exploited CPI reservoir (Grant et al., 1984; Truesdell and Lippmann, 1986) have been demonstrated using these methods.

REFERENCES

Fausto, J.J., Jimënez, M.E., and Esquer, I. (1981), Current state of the hydrothermal geochemistry studies at Cerro Prieto. CPIII, p. 188-220.

Fausto, J.J., Sanchez, A., Jimënez, M.E., Esquer, I., and Ulloa, F. (1979), Hydrothermal geochemistry of the Cerro Prieto geothermal field. CPII, p. 199-223.

Grant, M.A., Truesdell, A.H., and Manon, A. (1984), Production induced boiling and cold water entry in the Cerro Prieto geothermal reservoir indicated by chemical and physical measurements. Geothermics, v. 13, p. 117-140.

Halfman, S.E., Lippmann, M.J., Zelwer, R., and Howard, J.H. (1984), Geologic interpretation of geothermal fluid movement in the Cerro Prieto field, Baja California, Mexico. Am. Assoc. Petrol. Geol. Bull., v. 68, p. 18-30.

Manon, A., Sanchez, A., Fausto, J.J., Jimënez, M.E., Jacobo, A., and Esquer, I. (1979), Preliminary geochemical model of the Cerro Prieto geothermal field. Geothermics, v. 8, p. 211-222.

Stallard, M.L., Winnett, T.L., Truesdell, A.H., Coplen, T.B., Kendall, C., White, L.D., Janik, C.J., and Thompson, J.M. (1987), Patterns of change in water isotopes from the Cerro Prieto geothermal field, Baja California, Mexico: 1977-1986. Trans. Geothermal Resources Council, v. 11, p. 203-210.

Truesdell, A.H., D'Amore, F., and Nieva, D. (1984), The effects of localized boiling on fluid production at Cerro Prieto. Trans. Geothermal Resources Council, v. 8, p. 223-229.

Truesdell, A.H. and Lippmann, M.J. (1986), The lack of immediate effects from the 1979-80 Imperial and Victoria earthquakes on the exploited Cerro Prieto geothermal reservoir. Trans. Geothermal Resources Council, v. 10, p. 405-411.

Truesdell, A.H., Manon, A., Jimënez, M.E., Sanchez, A., and Fausto, J.J. (1979a), Geochemical evidence of drawdown in the Cerro Prieto geothermal field. Geothermics, v. 8, p. 257-265.

Truesdell, A.H., Rye, R.O., Pearson, F.J., Jr., Olson, E.R., Nehring, N.L., Whelan, J.D., Huebner, M.A., and Coplen, T.B. (1979b), Preliminary isotopic studies of fluids from the Cerro Prieto geothermal field. Geothermics, v. 8, p. 223-229.

BIBLIOGRAPHY

D'Amore, F., Fancelli, R., Saracco, L., and Truesdell, A.H. (1987) Gas geothermometry based on CO content--application in Italian geothermal fields. Proc. 12th Workshop on Geothermal Reservoir Eng., Stanford, CA, p. 247-252.

D'Amore, F. and Truesdell, A.H. (1984) Helium in the Larderello geothermal fluid. Geothermics, v. 13, p. 193-213.

Fournier, R.O. (1981), Application of water geochemistry to geothermal exploration and reservoir engineering: Chap. 4 in Geothermal Systems: Principles and Case Histories, L. Rybach and L.J.P. Muffler, eds. Wiley, New York, p. 109-143.

Haizlip, J.R. and Truesdell, A.H. (1988), Hydrogen chloride in super-heated steam at The Geysers geothermal field, California. Proc. 13th Workshop on Geothermal Reservoir Eng., Stanford, CA.

Henley, R.W., Truesdell, A.H., and Barton, P.B., Jr., (with contribution by J.A. Whitney) (1984), Fluid-mineral equilibria in hydrothermal systems. Soc. Econ. Geo. Reviews in Economic Geology, v. 1, 268 p.

Truesdell, A.H., Haizlip, J.R., Box, W.T., Jr., and D'Amore, F. (1987), Fieldwide chemical and isotopic gradients in steam from The Geysers. Proc. 12th Workshop on Geothermal Reservoir Eng., Stanford, CA, p. 241-246.

Truesdell, A.H. and Janik, C.J. (1986) Reservoir processes and fluid origins in the Baca geothermal system, Valles caldera, New Mexico. J. Geophys. Res., v. 91, no. B2, p. 1817-1833.

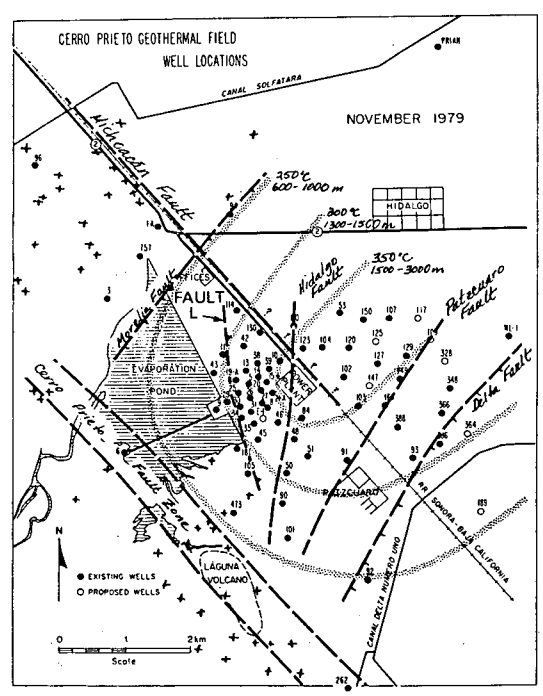


Figure 1. Map of Cerro Prieto showing well locations, faults (heavy dashed lines), simplified isotherms for variable depths (stippled), and locations of surface manifestations (pluses).

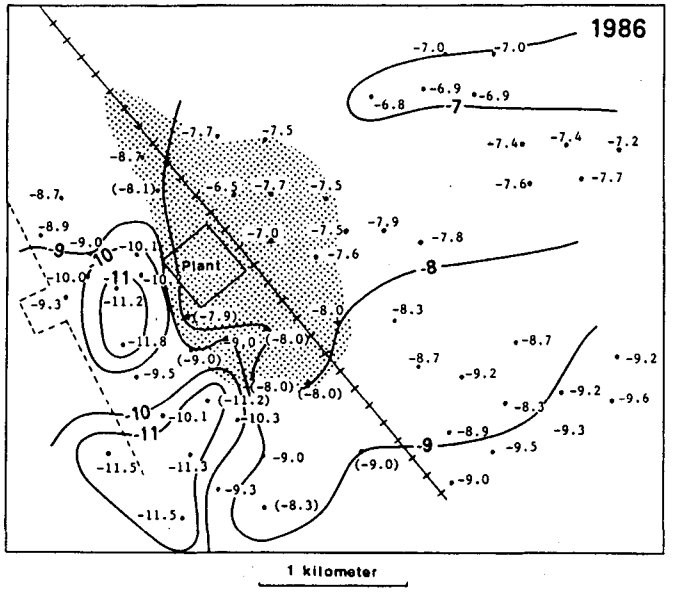


Figure 2. The distribution of oxygen isotope compositions of total discharge from Cerro Prieto wells in permil SMOW. Stippling shows an area of boiling. Note the western area where cold water enters along fault L (< -11 permil), the area of dilution (< -9 permil), and the upflow area in the northeast (< -7 permil).

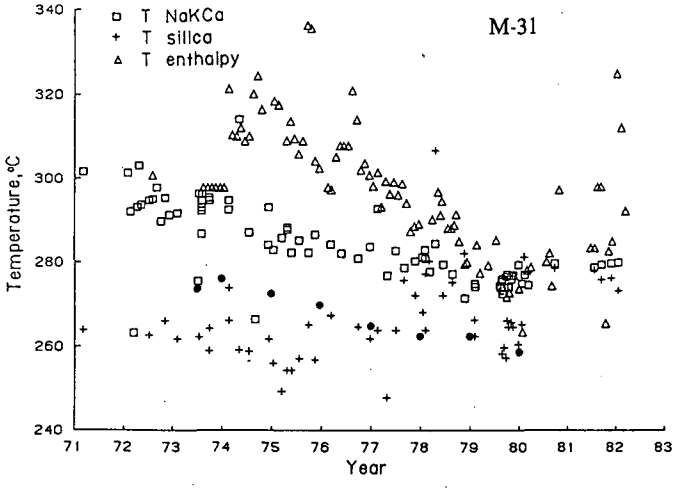


Figure 3. The temperature-enthalpy history of fluids from Cerro Prieto well M-31. The rapid increase and exponential decline of T_E indicates near-well boiling and heat transfer with a constant pressure boundary due to a "leaky" caprock. The boiling zone stabilized and excess enthalpy disappeared in 1980. The dots show calculated well-bottom temperatures, which are similar to values of T_{SIL}.

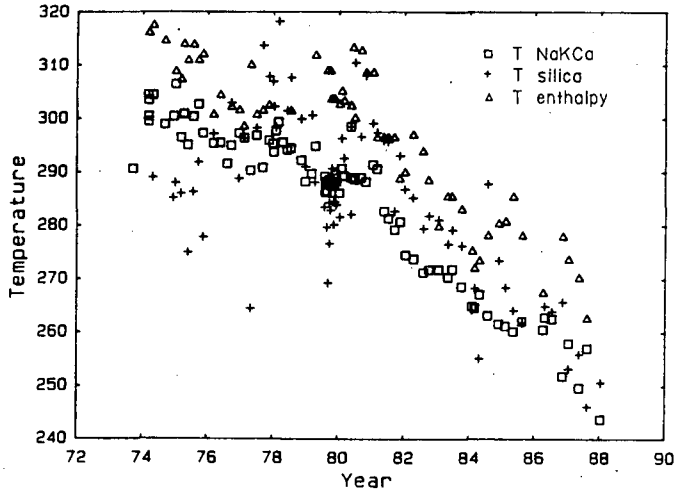


Figure 4. Temperature-enthalpy history of Cerro Prieto well M-35 showing a thermal front reaching the well in 1981. T_{NKC} declines faster than other temperatures because the water came from a cooler part of the reservoir. The final order shows $T_{SIL} > T_{NKC}$.

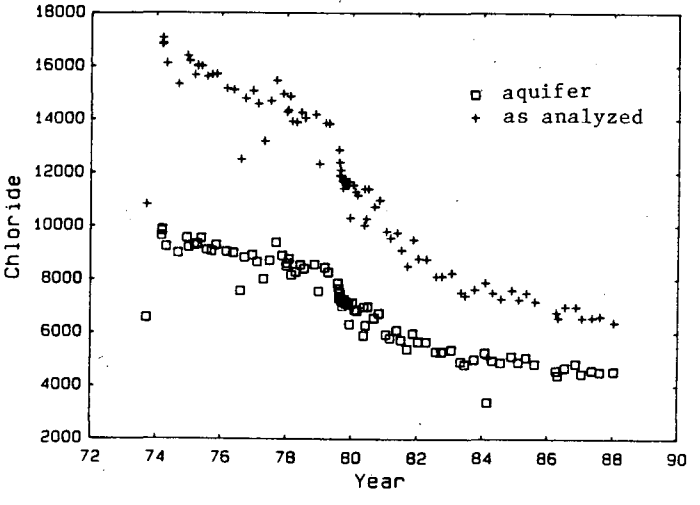


Figure 5. Chloride history of well M-35 showing the arrival of a chemical front in 1979 preceding the thermal front (fig. 4) by 2 years.

GEOPHYSICS

Session Chairperson

Charles Swift
(Chevron Resources)

Seismological Investigations in Geothermal Areas

E. L. Majer

Earth Sciences Division
Lawrence Berkeley Laboratory
University of California
Berkeley, California 94720

Abstract

Microearthquake and Vertical Seismic Profiling methods are being investigated for their usefulness for determining the static and dynamic properties of geothermal regions. At The Geysers and Salton Sea geothermal fields we have found velocity variations of up to 11% between *SH* and *SV* waves generated by rotating the shear wave vibrator orientation between two orthogonal polarizations. The effect is generally consistent with equivalent anisotropy expected from the known fracture geometry, although unexplained factors remain. These methods are useful for defining the geometrical properties of the fracture sets and possibly the fluid state of the reservoir. Microearthquake studies are now yielding useful information on the production parameters and appear to be more useful for reservoir monitoring than for exploration.

Introduction

The parameters affecting seismological phenomena in geothermal environments can be divided into two categories, static and dynamic. Static properties relative to the time frame of seismological measurements, i.e., the passage of a seismic wave, are: porosity, permeability, temperature, pressure, density, thermal conductivity and the state of the pore fluids. Dynamic properties include fluid movements, temporary phase changes, stress release, thermal expansion, or any process that causes changes in the static properties. In general, there are three seismological phenomena of interest related to the above: earthquakes (or discrete energy release), wave propagation effects, and "noise" generation. In this paper no attempt is made to review all seismological techniques that have been applied to geothermal problems. This paper will concentrate mainly on the techniques being used in wave propagation, i.e., active seismic, and microearthquake studies for geothermal applications, and to identify the areas of greatest promise for application to the geothermal industry.

Microearthquake Monitoring

Microearthquake (MEQ) studies are still very important, especially when applied to monitoring geothermal environments. Today, the primary use for MEQ studies is to relate production parameters (i.e., withdrawal and injection rates, pressure) to the spatial and temporal energy release distribution of the earthquakes. In addition there have been recent attempts to relate the high-frequency noise and MEQ activity (100 Hz and above) to regions of injection. Although there are declining budgets for geophysical measurements in these times of low fossil energy prices, there are still some geothermal operators that are using MEQ networks in the production environment. Because most geothermal regions lie in tectonically active regions, there is good reason to expect high MEQ activity. Although this activity alone may not be a reliable exploration tool, it seems that it is sensitive to the production parameters. Eberhart-Phillips and Oppenheimer (1984) reported a good correlation between production and MEQ activity at The Geysers geothermal field over times frames of years. However, it is still not clear why the activity is occurring and its exact relationship to fluid withdrawal and injection. Also, at The Geysers the MEQ activity has a depth limit that may be due to the brittle-plastic transition zone or due to the pore pressure conditions which may in turn be related to the steam content and water saturation levels. In any case, MEQ studies still seem to be very useful and deserve further research efforts. The problem of interpreting the MEQ data in the past has been a lack of a complete data set. That is, in most cases the procedure has been to install only one or two earthquake monitoring stations to determine if there is any activity. As time passed and fluid production increased more stations may have been added to the array, but by then the valuable baseline information had been lost. Because MEQ activity seems to be so strongly related to the changes in the reservoir parameters, or the dynamic properties, it is important that this activity be fully characterized from the beginning, especially when the reservoir is undergoing the largest changes. Last but not least is the need to correlate the MEQ parameters to the production parameters. This is becoming more common, but there are few complete, if any, long term case histories publically available.

Vertical Seismic Profiling and Crosshole Imaging

Today the geothermal reservoir engineer needs to have as a precise as possible picture of the subsurface. Ideally, one would like the capability to image the variation in subsurface inhomogeneities on the scale of meters and to be able to relate the measured seismic properties directly or indirectly to such parameters as fluid content, porosity, temperature and/or permeability. More often than not, the one single feature controlling these parameters is the fracture properties. Therefore there is a great need for having a means for the detection and location of dominant fractures. Vertical Seismic Profiling (VSP) alone or together with crosshole seismic imaging may offer a useful technique to characterize fractured media. However, the full potential of VSP demands three-component data. Fracture studies using VSP have been reported in a series of papers pointing out the

importance of using three-component data, particularly for fracture detection (Crampin, 1978, 1981, 1984a, 1984b, 1985; Stewart et al., 1981). The phenomena of shear wave splitting and anisotropy effects on S and P waves have also been discussed previously (Leary and Henyey, 1985).

Recent experimental (Myer et al., 1985, 1988) and theoretical work (Schoenberg, 1980, 1983) have supported a model in which apparent shear wave anisotropy is related to the "stiffness" of a fracture. Displacements across the fracture are not required to be continuous as a seismic wave passes. The discontinuity in seismic wave displacement at the fracture is taken to be linearly related to the stress through the stiffness of the fracture surface. According to this theory a fracture set may have a significant effect on wave propagation. Schoenberg shows that the velocity ratio for propagation perpendicular and parallel to the fracture set is a function of the spacing and the stiffness of the discontinuities. From this one can determine the average fracture spacing by measuring the velocity anisotropy and knowing or assuming a value for fracture stiffness.

Several tests of the applicability of VSP for fracture detection have been carried out in several different areas by LBL using multi-offset, multi-component sources and receivers. The first one was in the fall of 1984 (Majer et al., 1988). Compressional and shear-wave sources were used with a 3-component geophone in a steam well at The Geysers geothermal field in northern California. The objective was to test the VSP technique in an area with well-characterized fracture zones. Fracture content, dominant orientation and fracture spacing, were target parameters. Data were collected using $P-$ and $S-$ wave vibrators as sources. An innovation for this study was the use of orthogonal shear wave sources, accomplished by orienting the shear wave vibrator in two perpendicular directions for each geophone level with the expectation that fracture properties would be reflected in shear wave velocity anisotropy. Peacock and Crampin (1985) also reported finding shear wave splitting in a transversely isotropic media using a shear wave vibrator oriented at various angles relative to the axis of anisotropy.

In addition to the VSP survey, a short surface line consisting of vertical and horizontal geophones was laid out for high resolution P- and S-wave profiling in an attempt to map the steam zone from the surface. Previous reflection work in the area used only P-wave sources (Denlinger and Kovach, 1980). In addition there was another reason in using multicomponent surface reflection techniques for the mapping of the vapor zone. Ostrander (1984) has suggested comparing $P-$ and $S-$wave profiles for natural gas detection in porous media. Both the high resolution surface profile and the multi-offset VSP were designed insofar as possible to yield information on fracture content, structure, and the nature of pore fluids. Figure 1 is the layout of the experiment. Shown is the location of the surface shots, receivers, and CDP points, in addition to the location of the far VSP offset.

Despite some indications of reflection segments in the shot gathers, very little coherent energy was seen in the processed data from the surface line. It seems that the subsurface appears to a P wave as a very complex, non-reflective

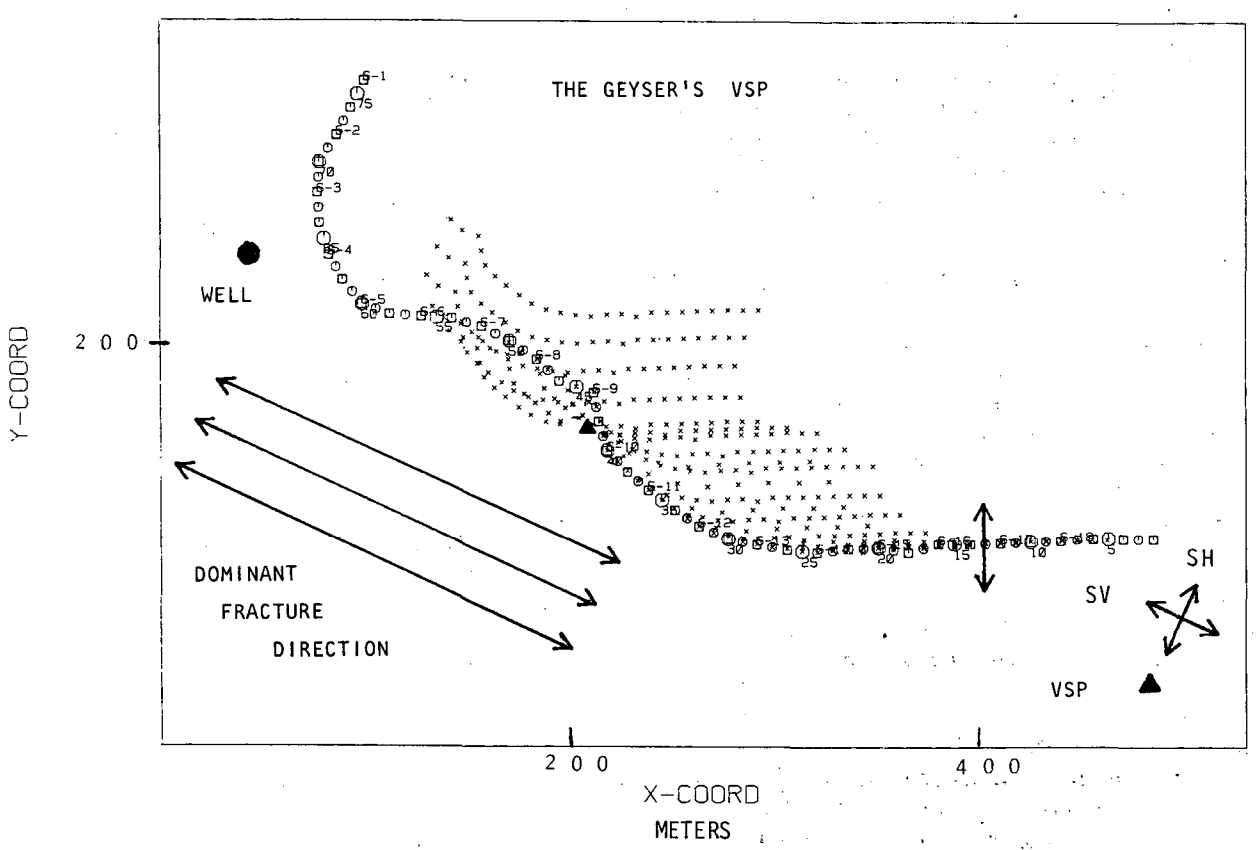


Figure 1. Survey layout at The Geysers experiment, with well, CDP line with midpoints and VSP vibrator positions (triangles), and source polarization directions. Direction of prominent, known fracturing is indicated.

medium. The shear wave surface line was only marginally better. The VSP data set, however, was of much higher quality than the surface line, though limited in quantity. The first interesting point to notice in the near-offset VSP data was a drop in Poisson's ratio at the bottom of the well, just at the top of the steam zone. Although it is not a dramatic change, it is significant if one remembers that average velocities are measured. On this basis we realize that over a few hundred feet occurs a substantial velocity difference. Combs and Rostein (1975) and Majer and McEvilly (1978) reported anomalously low V_P/V_S ratios in microearthquake studies of geothermal areas, and these data seem to confirm the phenomenon. In addition, it was possible to pick reflectors from the near-offset VSP data, however none correlated with the top of the low Poisson's ratio zone. The depths of the reflectors in the P-wave data were projected to be 1590, 2256, 2835 and 4116 m. The common deep reflector at approximately 4100 m is interesting in that microearthquake activity ceases at 4 to 5 km depth in this region (Majer and McEvilly, 1978; Eberhart-Phillips and Oppenheimer, 1984). If the seismic activity stops at this depth due to high temperature no major discontinuity in rock properties is required. The reflector, however, suggests the possibility of a relatively sharp change in rock properties at the base of the seismogenic zone.

The far-offset VSP yielded only a limited data set, yet the results may be the most significant of the survey. The formation in the surveyed interval is a highly fractured greenstone with very complicated structure. A cross-cutting fault is seen at the surface between the near and the far-offset VSP's, but its dip is unknown at depth. Figure 2 shows the relative arrival times of SH component from the SH source versus the SV arrival from the SV source at the far-offset VSP. This is probably the most dramatic evidence of how fractures affect the propagation of shear waves. Unfortunately we could not rotate the vibrator at the near-offset VSP. It appears that we see mixed effects of shear-wave splitting and shear-wave velocity anisotropy. Hodograms of the rotated data clearly show nonlinear polarization in the transverse plane, while the P-wave polarization is very nearly linear.

Both the anisotropy in shear wave velocity and the shear wave splitting observed in the far-offset VSP data can be interpreted in terms of the nature and distribution of the fractures in the rock mass. A single fracture of the type described earlier will produce a discontinuity in the displacement field of an incident seismic wave, and the magnitude of this displacement discontinuity is related to the stiffness of the fracture (Schoenberg, 1980; 1983). At The Geysers, geologic evidence suggests that the fracture spacing is small relative to the seismic wavelengths used; on the order of a few meters compared to seismic wavelengths which are on the order of a hundred meters. In such situations fractures can be represented by effective bulk material properties. Amadei and Goodman (1981), Schoenberg (1983) and others have shown that the bulk material properties of an otherwise elastic and isotropic rock mass containing a set of plane parallel fractures are equivalent to those of a transversely isotropic media described by five independent elastic constants. With this degree of symmetry, three body waves with mutually

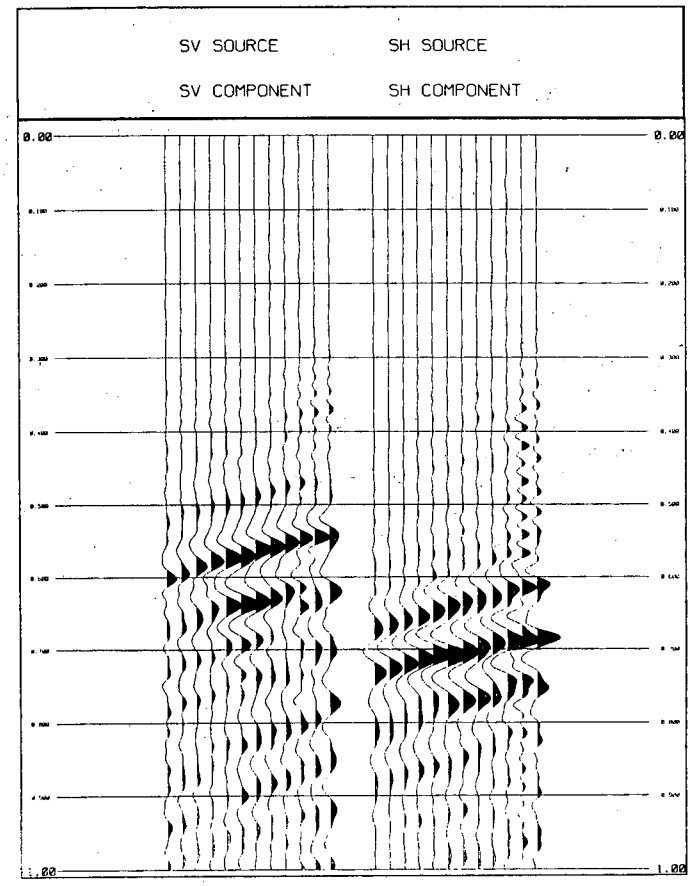


Figure 2. A comparison of the SH component from the SH source versus the SV component from the SV source for The Geysers VSP. Notice the 100 millisecond difference in arrival times.

orthogonal polarizations exist, but, except along an axis of symmetry, the particle motion is not coincident with the dynamic axes formed by the wave front and propagation vector, and shear waves will be split into two components with, in general, different velocities. At The Geysers the *SH* source was oriented perpendicular to strike of the predominant fracture set, which is assumed to dip nearly vertically. Similarly, the *SV* source yields shear wave data corresponding to a *qSV* wave (*SV* source/*SV* component) at the same propagation angle. For a vertical fracture set the *qSH* wave (*SH* source/*SH* component), should be significantly slowed relative to the *qSV* wave, as observed in Figure 2.

Shear wave splitting is evident in data for both the *SH* and *SV* sources. For the *SV* source, the velocities of the two waves are similar, and the evidence for splitting is in the non-linear particle motion. Propagation directions and source orientations are along symmetry directions of the equivalent transversely isotropic media, so that no shear wave splitting would be predicted if the geometry were exact and the inferred fracture set correct.

Given the values for fracture stiffness, the observed velocity anisotropy could be related quantitatively to fracture spacing. This analysis is not pursued due to the lack of such data. Research is currently underway to study the stiffness of

single fractures under dynamic loading conditions in order to obtain realistic values of stiffness.

In addition to work at The Geysers, we have also demonstrated the value of multicomponent VSP data for fracture detection and anisotropy determination at the Salton Sea Scientific well in southern California's Imperial Valley, and at the Cajon Pass scientific well near the San Andreas fault in southern California. Both surveys used three component sources (vibrators) and receivers, and are referred to as the SSVSP and CJVSP in the following paragraphs.

At the Salton Sea well (Daley, 1987), located near the Salton Sea Geothermal Field, standard VSP analysis techniques were used to identify reflecting horizons both within the survey interval (from 1500 to 5700 ft) and deeper in the well (Fig. 3). The reflection at 6900 ft in Figure 3 is associated with a fractured reservoir, and event C is interpreted as a scattered wave from a fracture zone near the well at a depth of 3000 ft. One goal of the SSVSP was location of fracture zones which are associated with the geothermal process. Seismic velocity anisotropy and the associated shear-wave splitting are indicators of fracturing utilized in the SSVSP analysis. Travel-time differences observed between orthogonal polarizations of the shear-wave source, labeled SV and SH, show a variation in anisotropy with depth. The SV-source motion is polarized in the radial direction towards the well, and the SH-source motion is polarized transverse to the radial. In an isotropic material these polarizations will generate the standard SV and SH type shear waves. Since the travel time is measured on a component with the same polarization as the source, travel time difference is a measurement of shear-wave velocity anisotropy.

Three component particle motion analysis of shear-wave arrivals was found to be an effective method for characterizing the subtleties in the S-wave splitting throughout the various zones in the well. Although the traveltime measurements show anisotropy of only around 1%, the particle motion analysis clearly showed changes in the S-wave propagation characteristics.

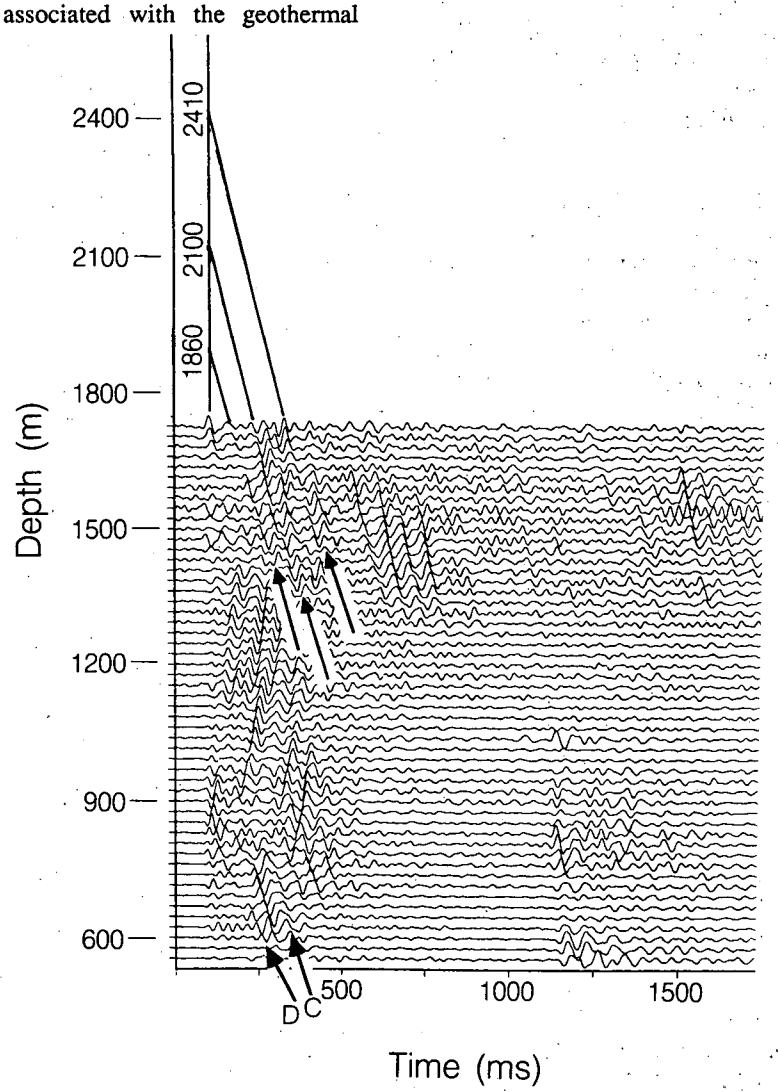


Figure 3. Reflector depth estimation for far-offset P-source, vertical-component at the Salton Sea VSP. Section is time shifted to align first arrivals and dip filtered to attenuate downgoing energy. Three deep events are identified with generation depths estimated at 6100, 6900 and 7900 ft. Event D is a P-wave reflection from 2800 ft. Event C is a vertically scattered P-wave event. The different moveout of events D and C indicate different modes of generation (Daley, 1987).

In the CJVSP survey (Daley et al., 1988) the shear-wave vibrator occupied one offset position for three runs of the borehole geophone, allowing three different S-wave polarizations to be obtained. These polarizations were radial and transverse to a line from the well, and the intermediate orientation, called SV, SH and S45, respectively. Complete data sets were obtained for the SV and SH polarizations (from surface to 1800 m, with 10 m spacing), but the third run was not finished giving coverage with the S45 source only from 1040 to 1630 m. By rotating the data from the P, SV and SH sources into the radial, SH and SV components, a nine-component display could be produced for the CJVSP (Fig. 4). The variation of events seen on each of these nine components shows the details which multicomponent VSPs produce compared to standard VSPs which have one source and one receiver component (such as the P-source, radial-component data shown in Fig. 4). In the CJVSP there is a significant interface near 500 m between the sedimentary Punchbowl Formation and the granitic basement rock. The effect of this contact is seen in the breakup of the first shear-wave arrival near 0.5 sec on the SV and SH components of the SV and SH sources. The contact is also delineated by the mode converted shear waves seen on the SV and SH components of the P and SV sources at 0.25 sec.

The three shear-wave data sets are shown in Figure 5 for the SH and SV component data. Anisotropic effects are clearly seen on the SH components where the S45-generated arrival between 0.7 and 1.1 s has a split waveform and a less coherent arrival. The effect of this anisotropy is also seen on the two component particle motion plots. The nearby San Andreas fault is expected to cause microfracturing which will affect the orientation of the shear-wave particle motion. In the particle motion plots, the S45- and SV-generated arrivals have a component of motion in the fault direction, but the SH-generated arrival, which is aligned with the fault, does not stay linear as we would expect. This type of particle motion analysis of the CJVSP data shows that factors other than the San Andreas fault are affecting the seismic anisotropy.

Conclusions

Microearthquake studies indicate a strong relationship between fluid production and injection and MEQ activity. MEQ studies may be very valuable for reservoir management purposes. Pilot VSP studies of shear wave propagation in several geothermal field yielded several interesting observations:

1. Anisotropy due to fractures causes up to an 11% velocity difference between *SH*- and *SV*- polarized waves generated at a common source point and recorded by a common downhole three-component geophone. There is little or no evidence of any P-wave anisotropy in these regions. However, the P-wave does cause forward scattering of shear waves from fractured regions.

2. The apparent anisotropy is consistent to first order with expected effects of the known dominant fracture sets.

3. There is a decrease in Poisson's ratio at the top of The Geysers production zone. The phenomenon was suggested in previous microearthquake studies, and is consistent with lower liquid saturation.

4. A weak but distinct *P*– and *S*–reflection from about 4 km at The Geysers may be related to conditions also responsible for the cessation of microearthquake activity below that depth.

The data sets collected have been limited and insufficient for detailed determination of fracture density and orientation. However, the data do suggest, as Crampin and others have pointed out, the potential value of using three-component multi-source VSP data to determine subsurface

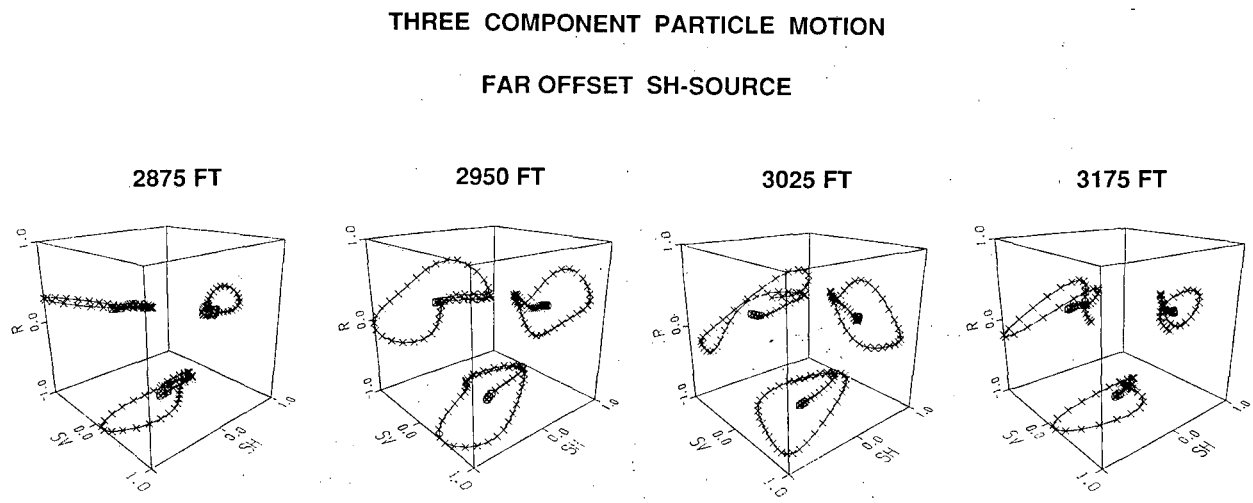


Figure 4. Nine-component display of Cajon Pass VSP data. Each section is a depth versus time display of the data from one source type (P, SH or SV) recorded on one geophone component (radial, SH or SV). The data has been rotated into radial, SH and SV components from the original, randomly rotated geophone recordings using the first P-wave arrival (Daley et al., 1988).

fracture content and orientation. In addition, if the theory developed by Schoenberg relating *SV* and *SH* velocity differences to fracture stiffness is applicable, information on average fracture spacing may also be obtained. The data presented show clearly a significant anisotropic effect on the propagation of shear waves through the fractured rock. The observations are consistent, to a first approximation, with a simple model in which the dominant fracture direction controls the apparent anisotropy directions.

Much work lies ahead in interpreting the data in actual field situations in terms of fracture properties. It appears promising, however, that useful information on fracture density and orientation can be obtained. Combined *S*– and *P*-wave data offer information on the nature of fracture-filling fluids. Amplitude and spectral information remain to be exploited. If the fracture stiffness model holds up, the spectrum of the reflected wavelet offers a valuable diagnostic tool in discriminating between reflections from welded interfaces and those from fracture sets. Further development of high-temperature receivers and downhole multicomponent sources will open up an entire new and effective method of mapping inhomogeneities and fractures in geothermal environments. Coupled with the MEQ and high frequency noise techniques the seismic methods appear to have a bright future in the geothermal industry.

Acknowledgements

This work was supported by the Secretary of Conservation and Renewable Energy, Office of Renewable Technologies, Division of Geothermal Technology of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

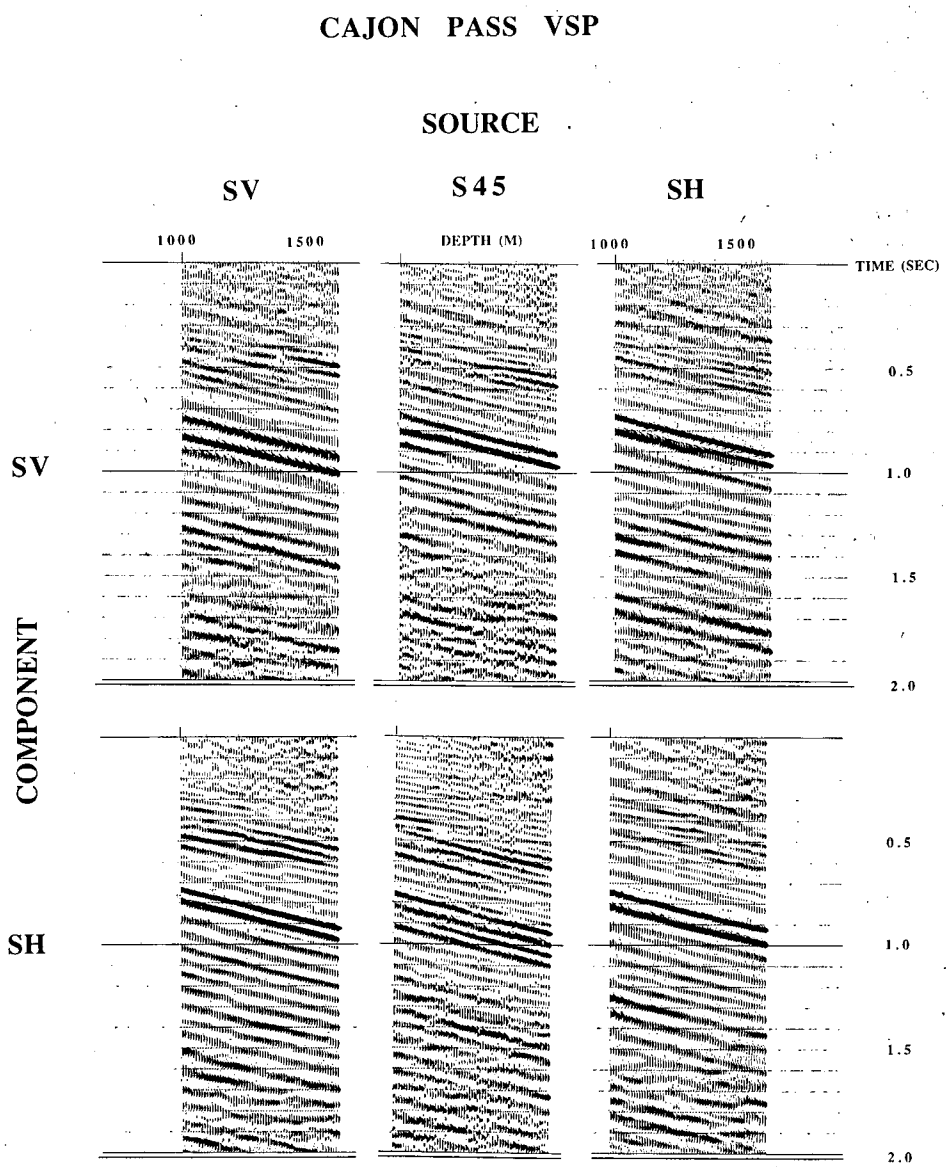


Figure 5. Shear-wave data from Cajon Pass VSP. The SV, SH and S45 sources are three polarizations of a shear-wave vibrator. The borehole geophone data has been rotated into SH and SV components. The variation in observed arrivals between sources can be used to study seismic anisotropy (Daley et al., 1988).

References

Amadei, B., and R.E. Goodman, 1981, A 3-D constitutive relation for fractured rock masses: *in* Studies in Applied Mechanics, Part 5B, Mechanics of Structured Media, Elsevier (International Symposium on the Mechanical Behavior of Structural Media, Ottawa), pp. 249-268.

Combs, J., and Y. Rostein, 1975, Microearthquake studies at the Coso geothermal area, China Lake, California: 2nd U.N. Symp. on the Dev. and Use of Geothermal Resources, San Francisco, p. 909.

Crampin, S., 1977, A review of the effects of anisotropic layering on the propagation of seismic waves: Geophys. J. Roy. Astron. Soc., v. 53, pp. 467-496.

Crampin, S., 1978, Seismic-wave propagation through a cracked solid: polarization as a possible dilatancy diagnostic: Geophys. J. Roy. Astron. Soc., v. 53, pp. 467-496.

Crampin, S., 1981, A review of wave motion in anisotropic and cracked elastic-media: Wave Motion, v. 3, pp. 343-391.

Crampin, S., 1984a, Effective anisotropic propagation through a cracked solid: In Crampin, S., Hipkin, R.G., and Chesnokov, E.M., eds., Proc. of the First Internat. Workshop on Seismic Anisotropy, Geophys. J. Roy. Astron. Soc., v. 76, pp. 135-145.

Crampin, S., 1984b, Anisotropy in exploration seismics: First Break, v. 2, pp. 19-21.

Crampin, S., 1985, Evaluation of anisotropy by shear wave splitting: Geophysics, v. 50, no. 1, pp. 142-152.

Daley, T.M., 1987, Analysis of P- and S-wave VSP data from the Salton Sea geothermal field, M.S. Thesis, LBL Report 24661, 253 pp.

Daley, T.M., T.V. McEvilly, and E.L. Majer, 1988, Multiply polarized shear-wave VSP's from the Cajon Pass drill hole, Geophy. Res. Letters, in press.

Denlinger, R.P. and R.L. Kovach, 1980, Seismic-reflection investigations at Castle Rock Springs in The Geysers geothermal area: U.S. Geol. Survey, Prof. Paper # 1141, pp. 117-128.

Eberhart-Phillips, D. and D.H. Oppenheimer, 1984, Induced seismicity in The Geysers geothermal area, California: J. Geophys. Res., v. 89, no. B2, pp. 1191-1207.

Leary, P.C. and T.L. Henyey, 1985, Anisotropy and fracture zones about a geothermal well from *P*-wave velocity profiles: Geophysics, v. 50, no. 1, pp. 25-36.

Majer, E.L. and T.V. McEvilly, 1978, Seismological investigations at The Geysers geothermal field: Geophysics, v. 44, no. 2, pp. 246-269.

Majer, E.L., T.V. McEvilly, F.W. Eastwood, and L.R. Myer, 1988, Fracture detection using P- and S-wave vertical seismic profiling at The Geysers, Geophysics, v. 53, no. 1, pp. 76-84.

Myer, L.R., D. Hopkins, and N.G.W. Cook, 1985, Effects of contact area of an interface on acoustic wave transmission characteristics: In Balkema, A.A., ed., Research and Engineering Applications in Rock Masses, Proc. 26th U.S. Symposium on Rock Mechanics, South Dakota School of Mines, v. 1, pp. 565-572.

Myer, L.R., D.L. Hopkins, and N.G.W. Cook, 1988, Effects of an interface in partial contact on attenuation of acoustic waves: Geophysics, (in press).

Ostrander, W.J., 1984, Plane wave reflection coefficients for gas sands of non normal angles of incidence: Geophysics, v. 49, no. 10, pp. 1637-1648.

Peacock, S., and S. Crampin, 1985, Shear-wave vibrator signals in transversely isotropic shale, Geophysics, v. 50, no. 8, pp. 1285-1293.

Schoenberg, M., 1980, Elastic wave behavior across linear slip interfaces: J. Acoust. Soc. Am., v. 68, no. 5, pp. 1516-1521.

Schoenberg, M., 1983, Reflection of elastic waves from periodically stratified media with interfacial slip: Geophys. Prosp., v. 31, pp. 265-292.

Stewart, R.R., R.M. Turpening, and M.N. Toksöz, 1981, Study of a subsurface fracture zone by vertical seismic profiling: Geophys. Res. Lett., v. 8, pp. 1132-1135.

RESEARCH IN BOREHOLE GEOPHYSICS

Phillip M. Wright, Stanley H. Ward,
Craig Beasley, Douglas LaBrecque,
John S. Stodt, and Howard P. Ross

Earth Science Laboratory
University of Utah Research Institute
Salt Lake City, Utah 84108

ABSTRACT

For the past five years, scientists at the University of Utah Research Institute have been working to develop electrical borehole geophysical methods for the purpose of detecting fractures and permeable zones in geothermal systems. Increasing the radius of investigation around a geothermal well would have obvious benefit since many holes find high temperatures but fail to encounter enough permeability to be good producers. The status of the research may be summarized as follows: (1) forward modeling algorithms have been developed and published to examine resistivity, mise-a-la-masse, MMR, CSAMT, and time-domain EM and to examine the effects of casing in wells and of geological and electrical noise; (2) a multi-array resistivity system has been designed and we are beginning construction of the prototype; and (3) about one year from now we will be seeking appropriate wells in geothermal areas in which to test the new method.

INTRODUCTION

A key problem worldwide in development of hydrothermal resources is locating permeable zones. Hot but unproductive holes have been drilled at most of the major geothermal areas in the world. Although none of the geophysical methods maps permeability directly, some of these methods can be used to measure physical property contrasts that can be interpreted, non-uniquely, in terms of subsurface permeability variation. At UURI, we have been developing electrical borehole techniques to detect and map resistivity anomalies due to permeable zones in the subsurface.

OBJECTIVE OF UURI R&D PROGRAM

The objective of our program is to develop and demonstrate the use of borehole electrical techniques in geothermal exploration, reservoir delineation and production. Our approach is: (1) develop computer techniques to model the various possible borehole electrical survey systems; (2) use these models to determine the best types of surveys to do and to help design a field data acquisition system; (3) use these same models to develop computer-based interpretation techniques based both on forward modeling and inversion; (4) test the new borehole field methods and interpretation techniques in one or more hydrothermal systems; and, (5) encourage the private sector to offer the new methods as a service to the geothermal industry.

BACKGROUND

It is important to understand the differences between geophysical well logging and borehole geophysics. In geophysical well logging, the instruments are deployed in a single well in a tool or sonde, and the depth of investigation is usually limited to the first few meters from the well bore. By contrast, borehole geophysics refers to techniques where energy sources and sensors are deployed both in boreholes and on the surface for the purpose of making borehole-to-surface, surface-to-borehole and/or borehole-to-borehole measurements. The depth of investigation is generally much greater in borehole geophysical surveys than it is in geophysical well logging. In addition, there is increased sensitivity of borehole surveys over surface surveys to subtle resistivity changes deep in the subsurface.

Prior to our work, only a few published papers considered computer modeling of down-hole electrodes for three-dimensional bodies. Daniels (1977) studied six buried electrode configurations and plotted normalized apparent resistivity or apparent polarizability against such configuration parameters as source and receiver depth, bipole length, receiver distance from body, depth of body, and distance of source and receiver from body center. Snyder and Merkel (1973), computed the IP and apparent resistivity responses resulting from a buried current pole in the presence of a buried sphere. Their plots were center -line profiles for normalized apparent

resistivity and normalized IP response. Dobecki (1980) computed the effects of spheroidal bodies as measured in nearby single boreholes using the pole-pole electrode array. Daniels (1983) illustrated the utility of hole-to-surface resistivity measurements with a detailed study of an area of volcanic tuff near Yucca Mountain, Nevada. He obtained total-field resistivity data for a grid of points on the surface with current sources in three drill holes, completed a layered-earth reduction of the data, and interpreted the residual resistivity anomalies with a three-dimensional ellipsoidal modeling technique.

Apart from efforts such as these, however, borehole electrical geophysical methods are poorly developed. One reason for this is that there are a large number of ways that borehole electrical surveys can be performed and it has been unclear which methods are best. At the same time, computer algorithms to model the several methods have not existed until recently so that it has not been possible to select among methods prior to committing to the expense of building a field system and obtaining test data.

SUMMARY OF RESULTS

At the beginning of the current phase of our work, Ross and Ward (1984) reviewed all literature pertaining to borehole electrical and electromagnetic methods up to that date. Their report gives a summary of this review and an annotated bibliography. It forms a useful reference for those interested in pursuing the topic in some detail.

Galvanic Resistivity

Most of our work to date has been with the galvanic, direct-current resistivity method. This preference is based largely on the fact that the down-hole equipment for such surveys consists only of electrodes, with no requirement for down-hole electronics, an obvious advantage in the hot, corrosive geothermal environment. Because the down-hole equipment is simple, adaptation of conventional logging equipment will be relatively straightforward.

Forward Modeling Algorithm Development. In 1982, Newkirk (1982) from our group completed a study of down-hole electrical resistivity with 3D bodies. Using a numerical modeling technique described by Hohmann (1975), theoretical anomalies due to a three-dimensional body composed of simple prisms were computed. Figure 1a and 1b illustrate anomalies on a surface resistivity survey produced by a narrow conductive body buried at a depth of 7 units with the electrode in the body (Fig. 1a) and off the end of the body (Fig. 1b). The peanut shaped anomaly shown in Figure 1a is particularly characteristic on surface resistivity surveys with the borehole electrode in the body. One basic shortcoming of Newkirk's (1982) algorithm is that it does not apply when the anomalous body becomes thin, i.e., to the case of delineation of fractures or thin fracture zones. To address this important problem, thin-body studies have been undertaken. These studies are aimed at targets simulating fracture zones which are thin relative to their other two dimensions.

Yang and Ward (1985a and 1985b) present theoretical results from surface integral equation modeling that relate to the detection of thin oblate spheroids and ellipsoids of arbitrary attitude. The effects of the surface of the earth are neglected and the body is assumed to be enclosed within an infinite homogeneous mass. The model results indicate that cross-borehole resistivity measurements are a more effective technique than single-borehole measurements for delineating resistivity anomalies in the vicinity of a borehole. Figure 2a shows cross-borehole resistivity responses of a vertical conductive fracture zone between two boreholes. The electrode configuration is the pole-pole array with electrode B fixed and electrode M moving in the second borehole. Several curves are plotted depending on the distance between the fracture and the second borehole. The larger anomalies occur when the second borehole is nearer to the fracture zone. Figure 2b shows anomalies for the same situation as Figure 2a except that now the fracture dips toward the first borehole. Figure 2c shows the effect of varying the resistivity contrast between a dipping fracture and the host medium. As expected, the large contrast cases produce the largest anomalies. Figure 2d shows the change in anomaly shape for the dipping fracture when four electrodes are placed down-hole instead of two (compare with Fig. 2b, EMX = 2.5). By study of a large suite of such graphs as these, the comparative capabilities of the various possible cross-borehole arrays can be examined.

A volume integral-equation approach by Beasley and Ward (1986) incorporates a half-space formulation, i.e., the earth's surface is not neglected. As with the surface integral-equation technique of Yang and Ward (1985a), the volume integral-equation method requires that only inhomogeneities be discretized. Any number of inhomogeneities of differing sizes and physical properties can be accommodated by this algorithm. The

algorithm is flexible in that it permits a buried electrode to be placed either inside (mise-a-la-masse) or outside (near-miss) the body. The maximum depth at which a body could be located and still produce a detectable anomaly on surface surveys was found to be dependent, as expected, upon the position of the buried electrode and upon the contrast in resistivity between the body and the host. It was found that locating the buried electrode just outside the body did not significantly alter the results from those when the electrode is embedded in the inhomogeneity.

Figures 3a, 3b and 3c show representative results from Beasley and Ward (1986). Each figure is a vertical section through the earth with contours of the resistivity anomaly. A borehole can be placed anywhere on this figure and the resistivity curve that would be observed in such a borehole with a single down-hole potential electrode would be given by the intersection of the borehole with the contours. The down-hole current electrode source is shown by the star.

A versatile algorithm for the borehole resistivity method is the 2-D finite element algorithm used by Zhao et al. (1986). The versatility arises from the fact that the entire subsurface is discretized. Since triangular elements are used for discretization, dipping bodies are readily handled. The algorithm also accommodates a layered-earth host environment. This algorithm was used to evaluate signal-to-noise ratio for various types of noise, including electrical and geologic noise. Figures 4a, 4b, and 4c show typical results. Figure 4a shows subsurface resistivity contours in section for a vertical fracture with a current source outside the body. This plot is similar to those given by Beasley and Ward (1986) in Figures 3a, 3b and 3c. The figure shows that the conductive fracture can be seen with receivers in a borehole on either side of the fracture, even further from the borehole than the source borehole. Figure 4b illustrates how subsurface topography due to geologic structure affects results. Note that the anomaly due to the fracture is obscured to a great extent by the resistivity pattern created by the contact. This is due in part also to the relatively large distance of the fracture from the down-hole current source, shown by the star. A current source in a borehole closer to the fracture would cause a much clearer anomaly. As Figure 4c shows, the anomaly becomes more evident when the down-hole electrode is near the lower extremity of the vertical fracture zone.

From the above studies we tentatively conclude the following: the cross-borehole method produces larger anomalies than does a single-bore hole method; the cross-borehole anomalies using a pole-pole array are smaller than those for a cross-borehole dipole-dipole array; the cross-borehole mise-a-la-masse method produces larger anomalies than the other cross-borehole methods; and, the anomalies due to a thin sheet are generally much smaller than those for a sphere, as is to be expected.

Casing. The d.c. resistivity methods obviously will not yield information if the borehole sensors are inside casing. However, many holes are only partly cased, and our studies show that the uncased portions of these holes can be used (LaBrecque and Ward, 1988a). Figure 5a shows the borehole profile of apparent resistivity for a long lateral array due to a nearby 3D conductive body. Also shown is a profile of apparent resistivity due to the body plus steel casing. The casing extends only part way down the hole. Once the far potential electrode (N) begins to exit the borehole, there is a large excursion in the apparent resistivity. This effect persists until potential electrode M is a short distance beneath the bottom of the casing. Thereafter, the effect of the 3D body is clearly seen. For a borehole-to-borehole survey, the effect of the casing increases as the surface potential dipole moves closer to the casing. Figure 5b illustrates the borehole apparent resistivity profiles for a surface dipole centered to one side of the top of the borehole. A single current electrode is run down the borehole with the return current electrode at infinity. The effect of the casing does not extend far beyond its lower extremity and the anomaly due to the body is clearly seen. As long as several dipole receivers are used on the surface, with varying distances from the borehole, then numerical modeling will readily permit recognition of the body in the presence of the casing.

Multi-array Borehole Resistivity and Induced Polarization. We believe that the best way to define the resistivity structure of the subsurface with the detail and resolution required for siting drill holes in the geothermal environment will be to collect a suite of data using combinations of borehole-to-borehole, borehole-to-surface and surface-to-borehole electrodes. We have devised the multi-array method, illustrated in Figures 6a and 6b for data collection. Transmitter and receiver electrodes would be deployed both on the surface and in one or more boreholes. Rapid switching between various combinations of electrodes would allow the collection of a redundant set of resistivity data for essentially all combinations of electrode positions. Such

a redundant data set would be used for two- and/or three-dimensional inversion to effect interpretation analogous to seismic geotomography and to the well-known CAT scan in the medical profession.

During the past year, we have acquired two data sets using the multi-array borehole method, one in a minerals application and one in a coal environment. These environments were chosen because the use of the field equipment was donated by Broken Hill Proprietary Limited, whose contribution to this phase of the project is gratefully acknowledged. The data are currently being used to develop and test inversion programs, discussed below. We are currently planning the development of research field equipment of our own which can be used in geothermal fields.

Inversion. Practical multi-array borehole field surveys will generate a large amount of data that comprise transmitter and receiver locations both on the surface and down the hole -- a redundant data set, as discussed above. It will be necessary to develop computer methods to handle these data in a cost- and time-effective manner. We are, therefore, working to develop inversion techniques for borehole d.c. resistivity surveys. Beasley and Ward (1988) are developing a technique to invert borehole resistivity field data to block resistivities. Preliminary testing of the algorithm has demonstrated its feasibility. LaBrecque and Ward (1988b) are studying another approach to inversion using moveable boundaries. Both of these algorithms are two-dimensional. It will be important to extent this work to three dimensions in order to perform the type of interpretation required by the geothermal environment. We also plan to extend the algorithms to handle induced polarization data in conjunction with resistivity data.

Time-Domain Electromagnetic Studies

Beginning with a 3-D integral equation algorithm developed by San Filipo and Hohmann (1985), West (1986) performed a model study to evaluate the time-domain electromagnetic (TDEM) response of a horizontal conductive body imbedded in a half-space. Figure 7 shows contours of apparent resistivity normalized by the resistivity of a homogeneous half-space for a horizontal 1000m X 1000m X 100m prism of resistivity 10 ohm-m. The details of the geometry of the transmitting loop, the body and the borehole are shown in the figure. The prism is clearly detected. The EM methods have great potential for use in borehole surveys, and we plan to pursue these methods once the galvanic methods discussed above are well developed and in use.

Controlled-Source Audiomagnetotelluric Studies

West and Ward (1988) studied the controlled-source audiomagnetotelluric (CSAMT) method for borehole applications. Figure 8 shows models for a 1000m X 1000m X 100m prism of resistivity 10 ohm-m in a background which is either 300 ohm-m or 1000 ohm-m. Clear-cut anomalies were obtained from which the top and bottom of the body can readily be deduced. As expected, the amplitude of the real component decreases with decreasing host resistivity due to increased attenuation of the primary wave. On the other hand, the amplitude of the imaginary component increases with decreasing host resistivity due to phase shift of the primary wave.

Magnetometric Resistivity Studies

Figure 9 was taken from the work of LaBrecque and Ward (1987) pertaining to magnetometric resistivity (MMR). The figure displays anomalies in the three magnetic field components measured at the surface over a prism of dimensions 2000m X 1000m X 100m. The resistivity of the prism is 10 ohm-m while that of the host is 100 ohm-m. The down-hole electrode is shown by the asterisk, while the return current electrode is at the surface 1000m vertically above the subsurface electrode. Hence, the source is a vertical electric bipole which yields no primary magnetic field at the surface. Note the quadripolar, monopolar and dipolar anomaly patterns for the x-, y- and z-components of the magnetic field, respectively.

DISCUSSION

The focus of our most recent work has been on pole-pole and pole-dipole direct current resistivity techniques utilizing multiple transmitter-receiver positions in various borehole-to-borehole and borehole-to-surface configurations to determine resistivity structure remote from the boreholes. These methods can be applied to open or partially cased holes. We will be developing a field data acquisition system over the next year for work in the geothermal environment. We believe that borehole techniques have substantial potential for locating zones of higher permeability in geothermal systems for siting drill holes and for determining appropriate directions in which to deviate holes in single- or multiple-leg completions.

ACKNOWLEDGEMENTS

The work described in this paper has been supported by the U. S. Department of Energy under contracts DE-AC03-84SF12196 and DE-AC07-85ID12489. We are grateful for the support of Marshall Reed of DOE-Headquarters, Marty Molloy of the San Francisco Operations Office, and Susan Prestwich of the Idaho Operations Office.

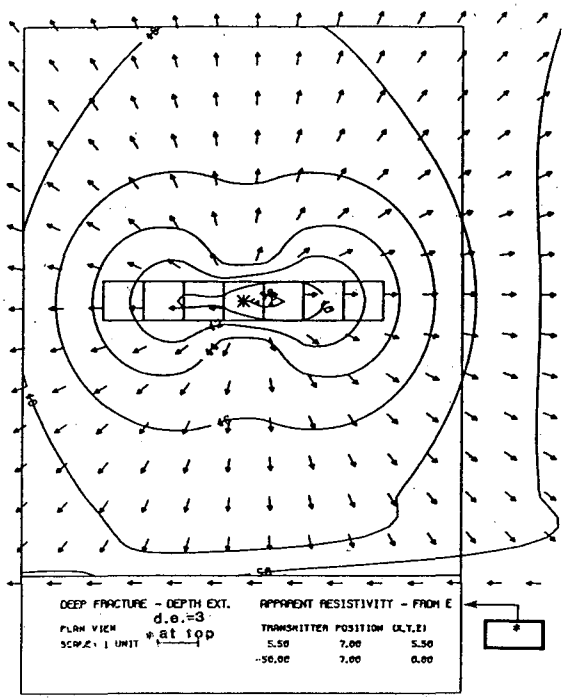


Figure 1a
Surface Resistivity anomaly due to deep fracture with downhole electrode in body.

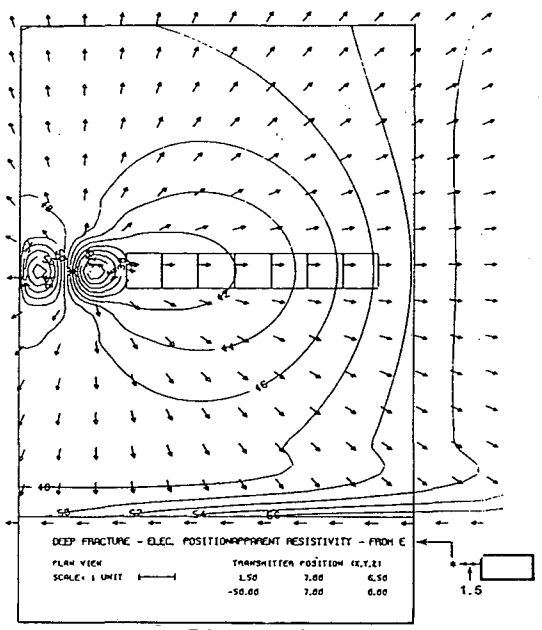


Figure 1b
Surface resistivity anomaly due to deep fracture with downhole electrode at side of body.

REFERENCES

Beasley, C. W., and Ward, S. H., 1986, Three-dimensional mise-a-la-masse modeling applied to mapping fracture zones: Geophysics, 51, 96-111.

Beasley, C. W., and Ward, S. H., 1988, Cross-borehole resistivity inversion: Expanded Abstracts, Annual International Meeting and Exposition, Society of Exploration Geophysicists, Anaheim, CA.

Daniels, J. J., 1977, Three-dimensional resistivity and induced-polarization modeling using buried electrodes: Geophysics, 42, 1006-1019.

Daniels, J. J., 1983, Hole-to-surface resistivity measurements: Geophysics, 48, 897-97.

Dobecki, T. L., 1980, Borehole resistivity curves near spheroidal masses: Geophysics, 45, 1513-1521.

Hohmann, G. W., 1975, Three-dimensional induced-polarization and electromagnetic modeling: Geophysics, 40, 309-324.

LaBrecque, D. J., and Ward, S. H., 1987, Evaluation of borehole MMR for fracture detection: Report DOE/SAN/12196-23, Earth Science Laboratory, University of Utah Research Institute,

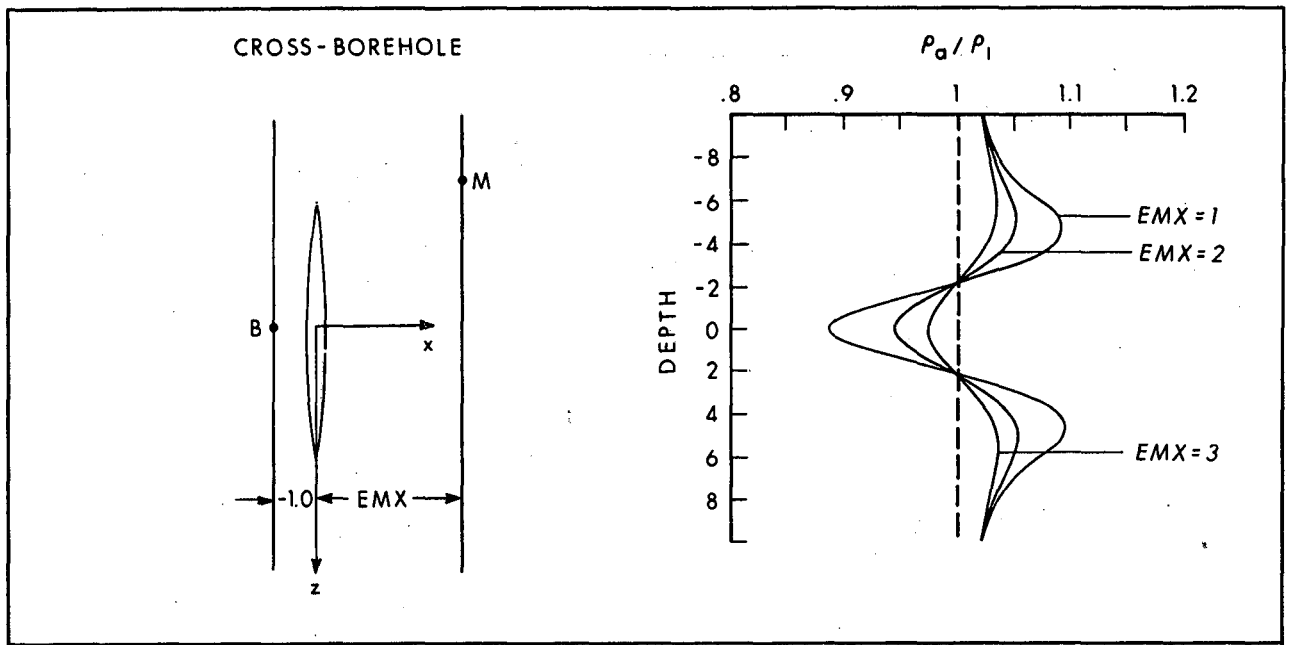
LaBrecque, D. J., and Ward, S. H., 1988a, Effect of a metal well casing on #-D interpretation of borehole resistivity data: Expanded Abstracts, Annual International Meeting and Exposition, Society of Exploration Geophysicists, Anaheim, CA.

LaBrecque, D. J., and Ward, S. H., 1988b, Two-dimensional inversion of cross-borehole resistivity data using movable boundaries: Expanded Abstracts, Annual International Meeting and Exposition, Society of Exploration Geophysicists, Anaheim, CA.

Newkirk, D. J., 1982, Downhole electrode resistivity interpretation with three--dimensional models: Masters Thesis, Dept. of Geology and Geophysics, Univ. of Utah.

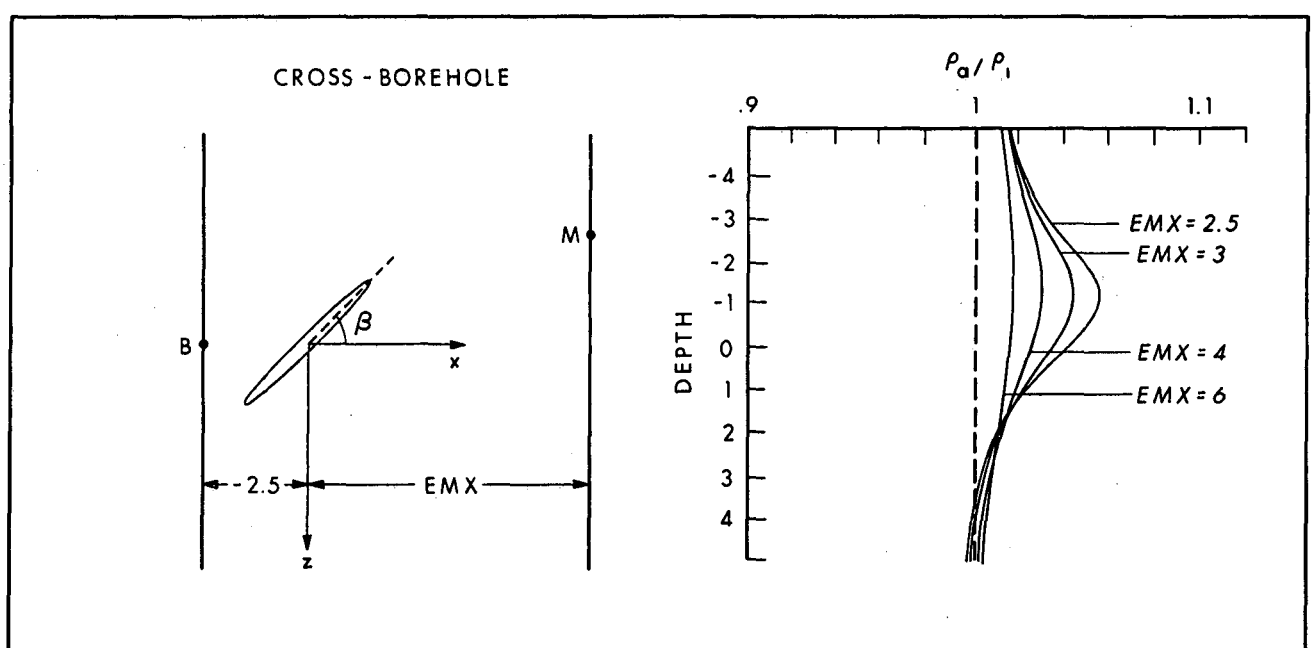
Ross, H. P. and Ward, S. H., 1984, Borehole electrical geophysical methods-- a review of the state-of-the-art and preliminary evaluation of the application of fracture mapping in geothermal systems: University of Utah Research Institute, Earth Science Laboratory Report DOE/-SAN/12196-2, ESL-141, 61p.

San Filipo, W. A., and Hohmann, G. W., 1985, Integral equation solution for the transient electromagnetic response of a three-dimensional body in a conductive half-space: Geophysics, 50, 798-809.



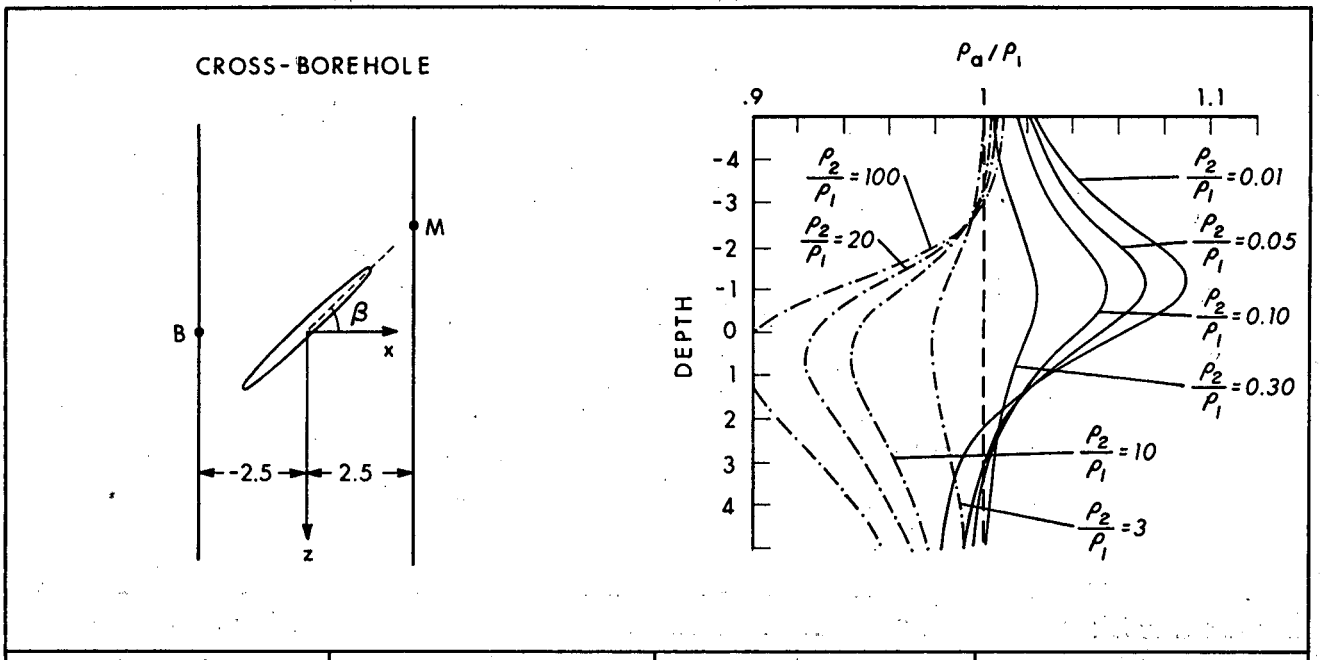
Electrode Configuration	Body Size	Angles	Resistivity Contrast
Fixed Source Moving Electrode SBX=-1.0 SBY=SBZ=0 EMY=0	a = 6 (z) b = 2 (y) c = 0.2 (x)	$\alpha = 0°$ $\beta = 90°$ $\gamma = 0°$	$\frac{\rho_2}{\rho_1} = 0.10$

Figure 2a
Downhole cross-borehole resistivity anomalies for vertical fracture showing the effect of varying distance from fracture to second borehole.



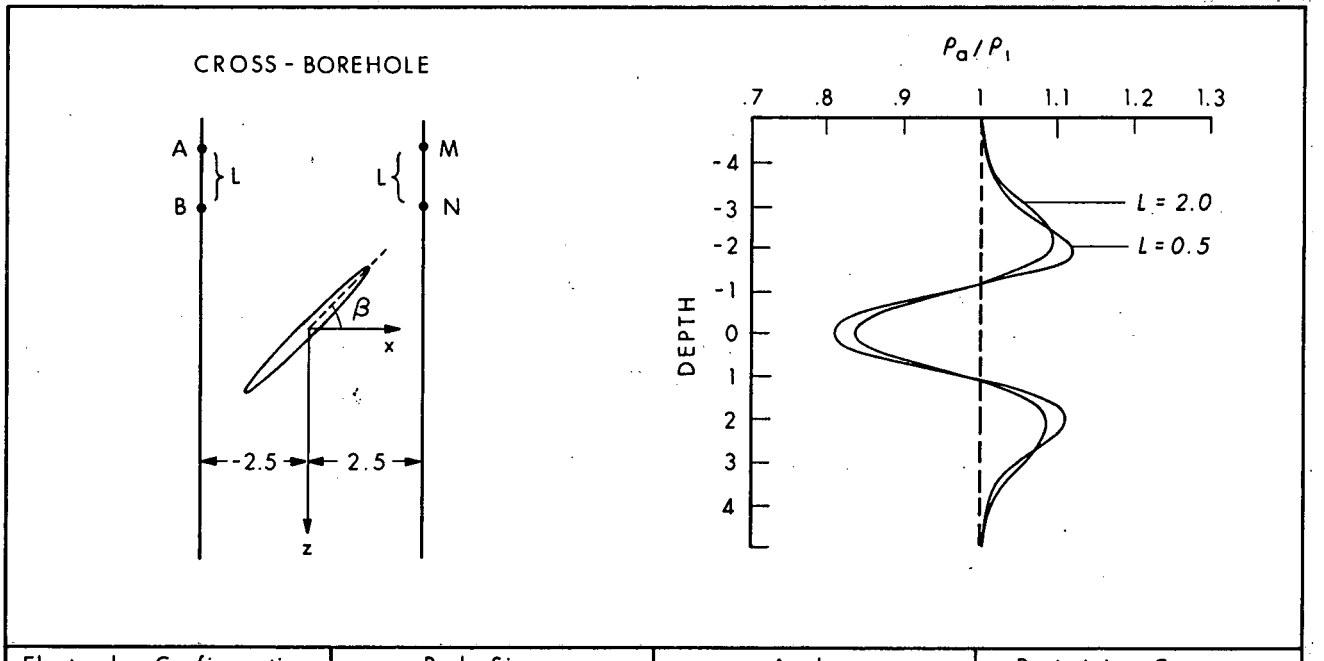
Electrode Configuration	Body Size	Angles	Resistivity Contrast
Fixed Source Moving Electrode SBX=-2.5 SBY=SBZ=0 EMY=0	a = 2 b = 2 c = 0.2	$\alpha = 0°$ $\beta = 45°$ $\gamma = 0°$	$\frac{\rho_2}{\rho_1} = 0.10$

Figure 2b
Downhole cross-borehole resistivity anomalies for dipping fracture showing the effect of varying distance from fracture to second borehole.



Electrode Configuration	Body Size	Angles	Resistivity Contrast
Fixed Source Moving Electrode SBX=-2.5 SBY=SBZ=0 EMX=2.5 EMY=0	a = 2 b = 2 c = 0.2	$\alpha = 0°$ $\beta = 45°$ $\gamma = 0°$	——— $\frac{\rho_2}{\rho_1} < 1$ —·—·— $\frac{\rho_2}{\rho_1} > 1$

Figure 2c
Downhole cross-borehole resistivity anomalies for dipping fracture showing the effect of varying resistivity contrast between fracture and host medium.



Electrode Configuration	Body Size	Angles	Resistivity Contrast
Moving Bipole Source Moving Bipole Receiver SAY = SBY = 0 EMY = ENY = 0	a = 2 b = 2 c = 0.2	$\alpha = 0°$ $\beta = 45°$ $\gamma = 0°$	$\frac{\rho_2}{\rho_1} = 0.10$

Figure 2d
Downhole cross-borehole resistivity anomalies for dipping fracture showing the effect of dipole length for downhole electrodes.

Snyder, D. D., and Merkel, R. M., 1973, Analytic models for the interpretation of electrical surveys using buried current electrodes: Geophysics, 38, 513-529.

West, R. C., 1986, The borehole transient EM response of a three-dimensional fracture zone in a conductive half-space: MS Thesis, Department of Geology and Geophysics, University of Utah.

West, R. C., and Ward, S. H., 1988, The borehole transient EM response of a three-dimensional fracture zone in a conductive half-space: in press in Geophysics.

Yang, F. W., and Ward, S. H., 1985a, Single- and cross-borehole resistivity anomalies of thin ellipsoids and spheroids: Geophysics, 50, 637-655.

Yang, F. W., and Ward, S. H., 1985b, On sensitivity of surface-to-borehole resistivity measurements to the attitude and the depth to the center of a 3-D oblate spheroid: Geophysics, 50, 1173-11-78.

Zhao, J. X., Rijo, L., and Ward, S. H., 1985, Evaluation of the ratio of signal-to-noise in cross-borehole electrical surveys: Geophysics, 51, 1978-1991.

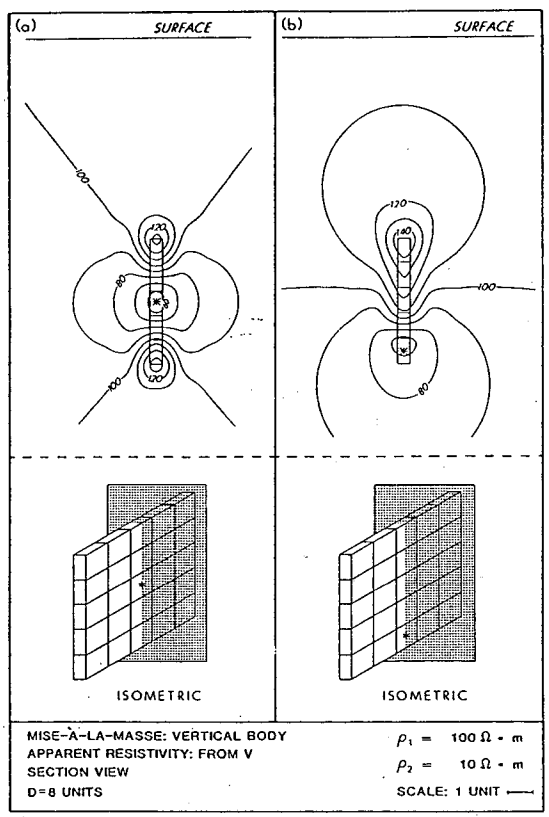


Figure 3a
Subsurface resistivity contours for a vertical permeable zone with an imbedded downhole current source.

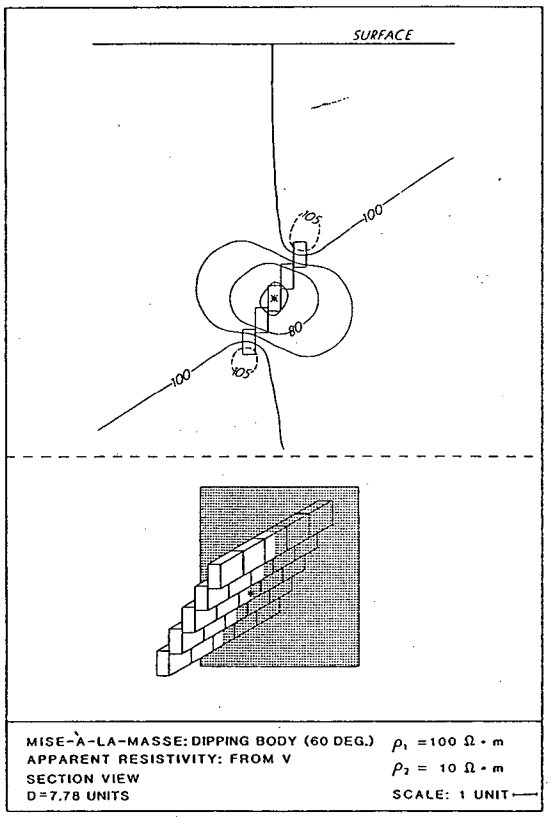


Figure 3b
Subsurface resistivity contours for a dipping permeable zone with an imbeded downhole current.

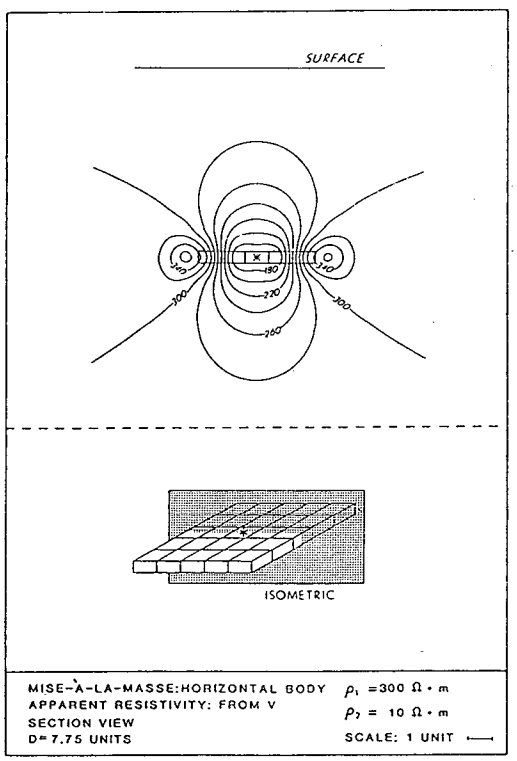
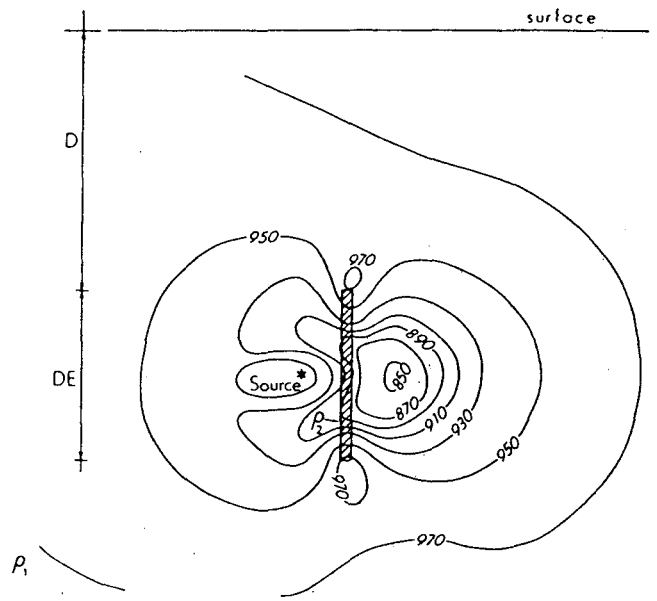


Figure 3c
Subsurface resistivity contours for a horizontal permeable zone with an imbedded downhole current source.



D = 6 units
DE = 4 units
W = .25 unit

Scale 1 Unit
ρ_1 = 1000
ρ_2 = 100

Figure 4a
Subsurface resistivity contours for a vertical permeable zone with current source to the side.

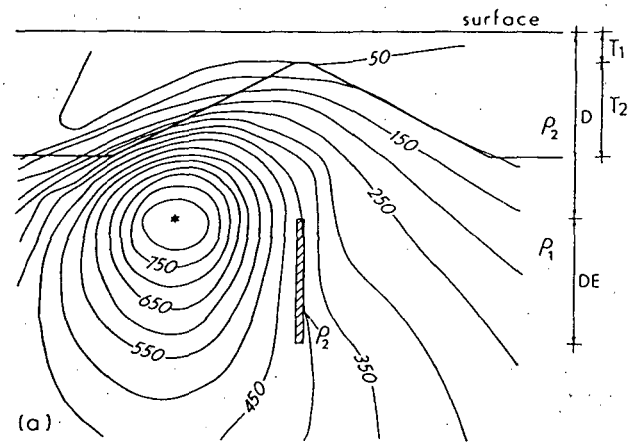
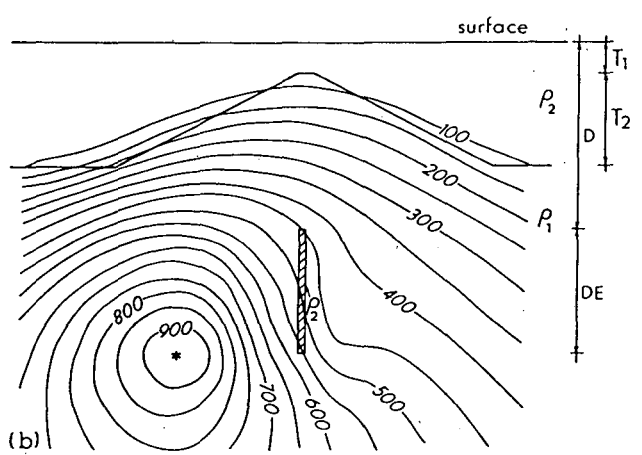


Figure 4b
Subsurface resistivity contours for a vertical permeable zone beneath geologic structure with varying positions of the downhole current electrode.



Scale 1 Unit
ρ_1 = 1 000 Ω•m
ρ_2 = 10 Ω•m
* = Source

D = 6 units
DE = 4 units
T_1 = 1 unit
T_2 = 3 units
W = .25 unit

Figure 4c

Subsurface resistivity contours for a vertical permeable zone beneath geologic structure with varying positions of the downhole current electrode.

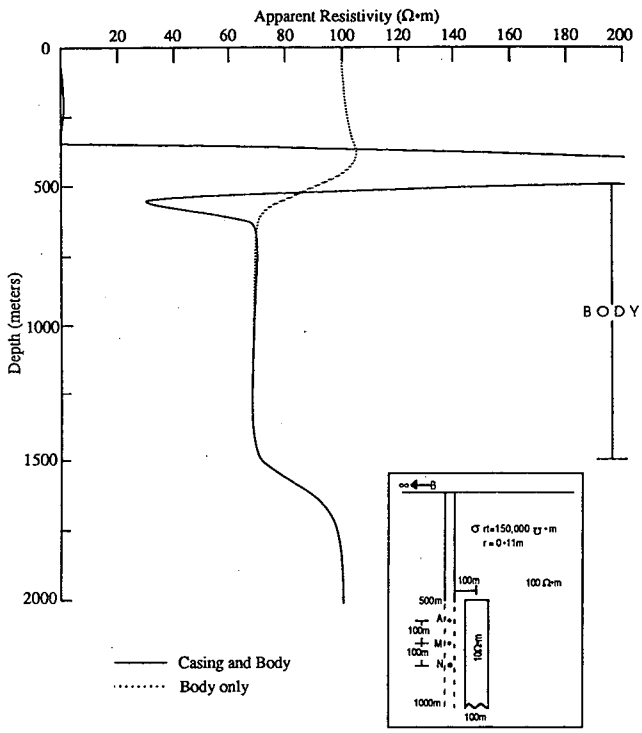


Figure 5a
Borehole apparent-resistivity profile for a 100 m lateral array down a borehole cased to 500 m. A 3-D body lies adjacent to the borehole as shown in the figure.

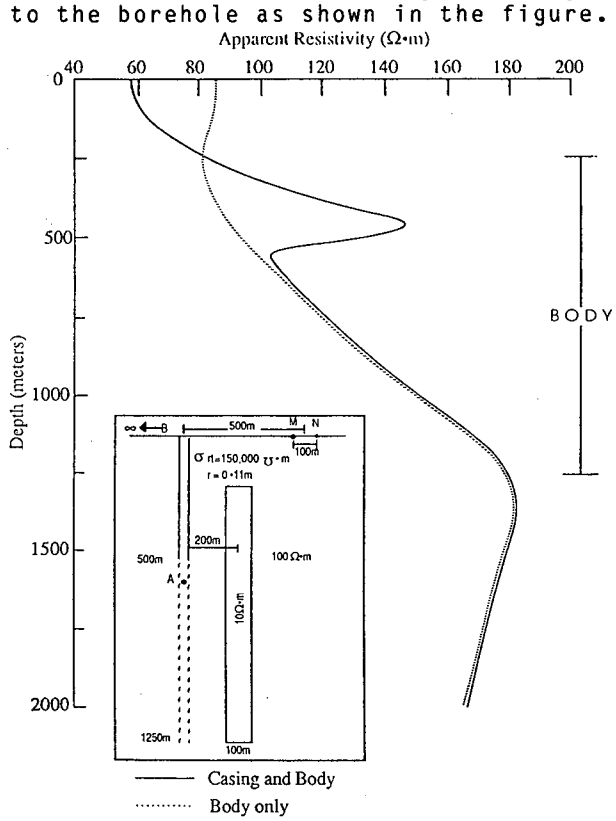


Figure 5b
Borehole apparent-resistivity profile for a pole source downhole and a 100 m receiving dipole at surface. The borehole is cased to 500 m; all parameters are shown in the figure.

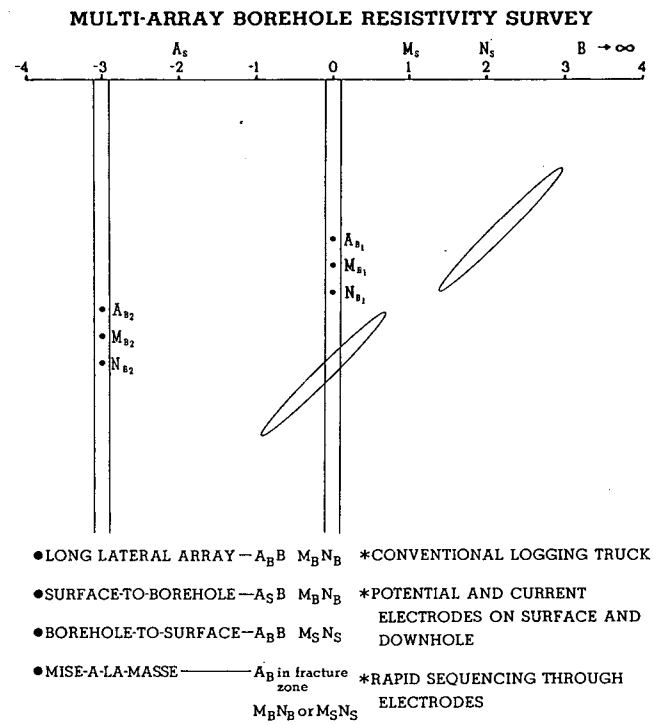
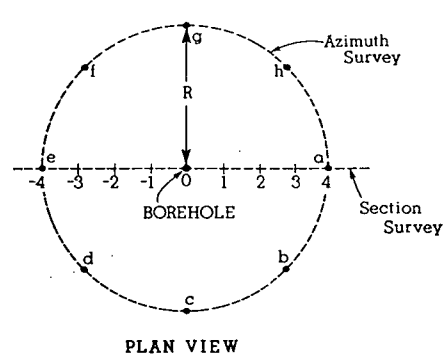


Figure 6a



LOCATIONS OF A_S : -4,-3,-2,-1,0,1,2,3,4 SECTION SURVEY

a,b,c,d,e,f,g,h AZIMUTH SURVEY

Figure 6b

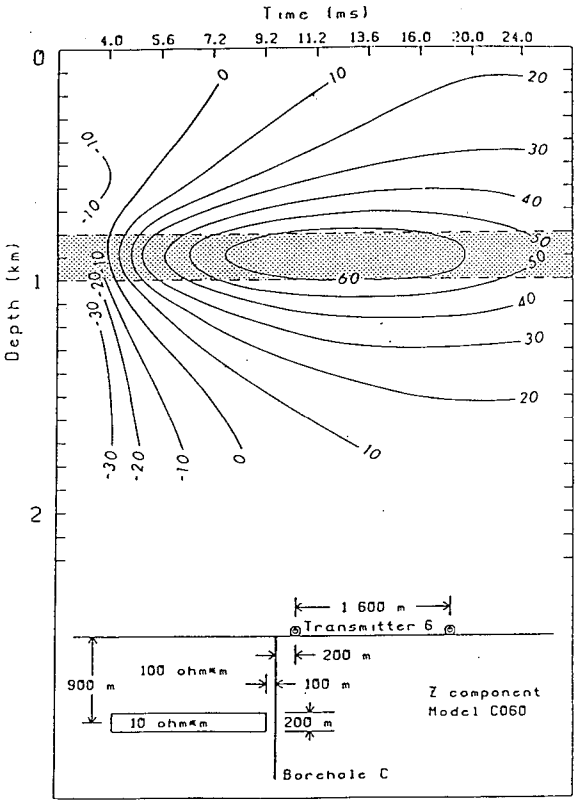


Figure 7
Percent difference (PD) in dB_z/dt for a 10 ohm meter target in a 100 ohm meter half-space. PD =(total - primary)/primary x 100%, where primary = half-space response.

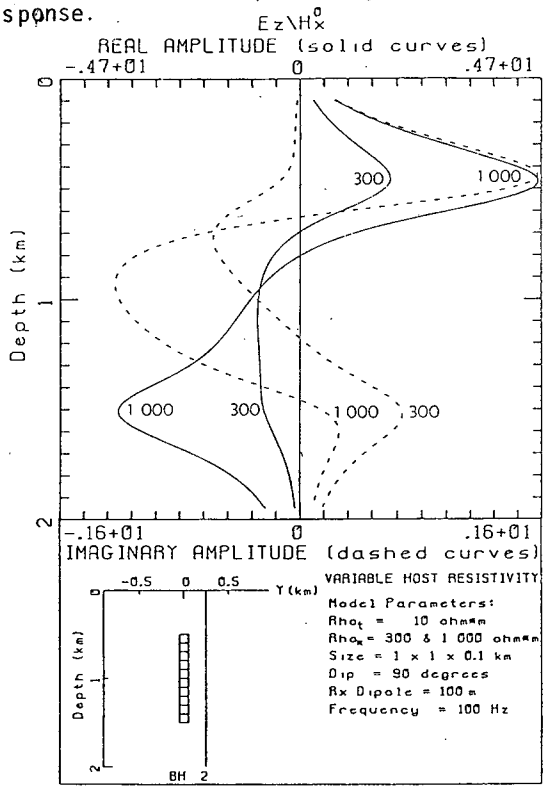


Figure 8
E_z/H_x^0 profiles for borehole near a vertical conductive prism embedded in a half-space.

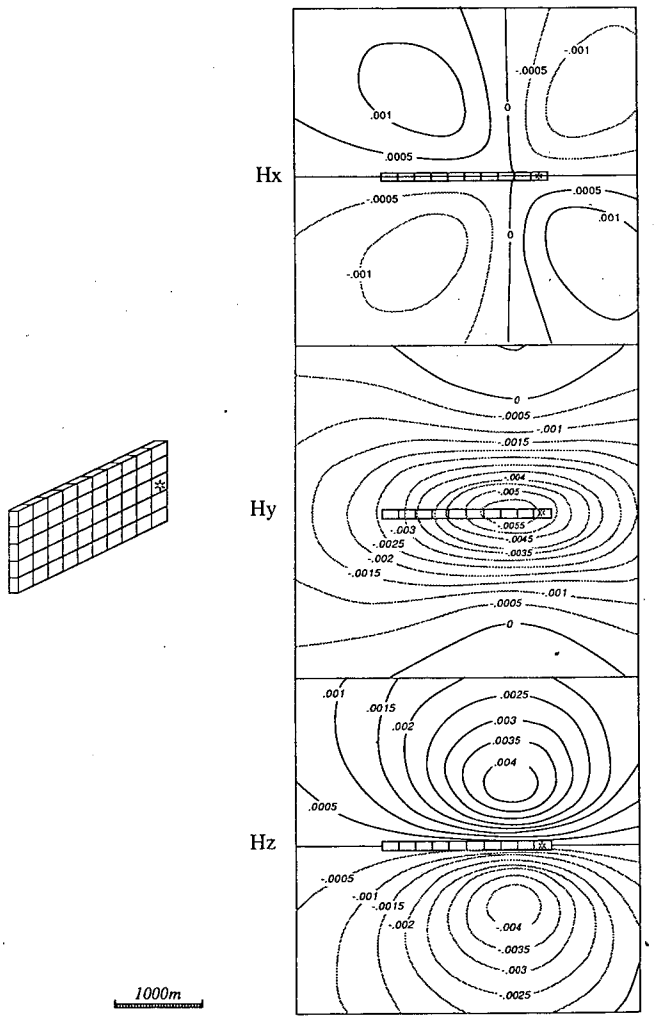


Figure 9

Magnetic fields over a vertical prism with strike length of 2000 m. The positive current electrode is located at a depth of 1000 m, 800 m in the x (strike direction) from the center of the dike and 0 m in the y direction from the center of the dike. Contours are in nT/A. (after LaBrecque and Ward, 1987).

Geophysical Programs at LLNL

Paul W. Kasameyer
Jay Zucca
Steve Jarpe
Teresa Hauk

Lawrence Livermore National Laboratory
Livermore, California 94550

ABSTRACT

Lawrence Livermore National Laboratory (LLNL) has a number of geophysical projects related to geothermal energy. These projects are funded by the DOE Geothermal Technology Division (GTD) and the DOE Office of Basic Energy Sciences. In this paper, we describe GTD-funded projects that take advantage of the LLNL Configurable Seismic Monitoring System (CSMS) to study the seismic attenuation structure of Medicine Lake volcano, and to determine if there are useful sounds emitted during the Salton Sea Scientific Drilling Project production-injection test.

The CSMS was designed to provide a variety of seismic recording configurations in order to meet anticipated needs of the LLNL Treaty Verification Program. Our system consists of three main parts: remote stations, a central recording station, and telemetry between them. The central recording system, which is housed in a trailer, enables us to control a number of remote sites, and to collect and archive full-waveform digital data from them. The system can run in either event-detecting or continuous mode, and the central recording station can be controlled through a phone modem from our lab. The system allows us to collect high-quality data in rugged terrain, or to carry out a long-term monitoring test with no people on-site.

Medicine Lake Seismic Imaging Project

We participated in a USGS-run seismic imaging experiment at Medicine Lake volcano in northeast California. The primary purposes of this deployment were to:

1. Produce a detailed three-dimensional seismic velocity and attenuation image of the Medicine Lake caldera.
2. To demonstrate that this method works so it could be used at additional sites.
3. To collect a high quality, multi-component data set to be used for the development and testing of advanced seismic measurement and interpretation methods.

Using the CSMS, we placed 20 three-component remote stations in the least accessible parts of the volcano, and the USGS placed 120 single-component seismometers with independent recorders and set them to run for a specific length of time. Eight 1300-1800 kg charges were detonated in a circle with a 50 km radius about the receivers, and more than 1100 seismograms were recorded to be used to produce a three-dimensional image of the caldera. The USGS picked arrival times for all the signals in order to construct a travel-time image. In a parallel effort, LLNL produced an attenuation image from the slope of the power spectra as a function of frequency. As is reported in a *Journal of Geophysical Research* paper to be published by John Evans of the USGS and Jay Zucca of LLNL, the combined images were interpreted to indicate that only a small magma body might exist under the center of the volcano, and to locate areas which appear to be "dry", perhaps indicating temperatures above the boiling point of water. Our next effort will be to use existing data to produce an attenuation image of Newberry volcano.

Salton Sea Seismic Deployment

We have been studying the use of geophysical surveys to monitor processes in geothermal reservoirs during injection and production. One attractive geophysical method is to listen for micro-seismicity from the reservoir. Micro-seismicity has been detected at a number of injection or production sites, but we can not predict when it occurs. Our goal is to collect case studies to identify the circumstances that cause micro-seismicity, and to determine when it can be used to monitor injection.

The planned flow test at the Salton Sea Geothermal Field (SSGF), in southern California, is an excellent opportunity to collect a case history of injection-induced microseismicity. Because it is part of an integrated flow test, the results of our survey can be related to geology, pressures and flow distributions estimated from reservoir engineering models.

We have instrumented the injection site for several months before injection began on June 1, 1988, and continued to observe seismic events for about one month after. This will give us some idea of the background seismicity, and the sources of natural noise, and observations of any events during and shortly after the thirty-day flow test. The traditional method of deploying a seismic network will be supplemented by three small-aperture arrays whose sensitivity can be aimed in different directions. The arrays will allow us to study continuous noise as well as discrete events.

During this deployment, we will:

1. Determine if there are signals associated with the flow test, and assess what they tell us about the reservoir.
2. Evaluate the natural seismic noise previously detected near the SSGF. (Our preliminary results suggest that the only continuous source of natural noise is waves from the shore of the Salton Sea.)
3. Study the natural seismicity distribution and fault dynamics in this zone of extension between the San Andreas and Brawley faults.

Geophysical Progress in Fracture Detection and Mapping

Norman E. Goldstein

Earth Sciences Division, Lawrence Berkeley Laboratory
University of California, Berkeley, California 94720

Abstract

The Lawrence Berkeley Laboratory (LBL), in cooperation with geothermal developers, has been investigating the applicability of advanced fractured detection and mapping techniques to geothermal problems. Both seismic and non-seismic geophysical techniques have been under study. Among the non-seismic methods, 3-D gravity inversions, self-potentional (SP) analyses, and crosshole electromagnetic (EM) tomography have received most of our attention. Where detailed gravity data are available, 3-D gravity inversions may be able to resolve concealed faults due to either structural discontinuities (e.g., differential vertical displacement) or hydrothermal densification due to fluid-rock or fluid-fluid reactions. SP anomalies are often found related to faults, fissures and thermal manifestations, but it has been difficult to explain the SP anomalies quantitatively in terms of subsurface processes. A sharp SP anomaly over the East Mesa field conforms to the trace of a suspected fault, and may be the result of a shallow fluid-fluid junction due to a permeability contrast across the fault zone. Surface-to-borehole and crosshole EM techniques are being evaluated numerically at audio frequencies (100 Hz to 20 kHz). Although we do not yet have field data, the forward model and inversion calculations have been encouraging.

Introduction

This paper reviews LBL research, in progress or recently completed, dealing with our attempts to map faults and fracture zones using geophysical methods. The discussions will be limited to the non-seismic methods, as Ernie Majer (this volume) has covered the complementary seismic research activities at LBL.

Our guiding objective has been to reduce field development costs through better targeting of wells. It is reported that in many geothermal fields the difference between marginal and productive wells is whether the well intersects one or more open and, presumably, well-connected fractures. Reliance on surface fault features, such as drainage patterns, hydrothermal alteration patterns, and areas of highest near-surface temperature may not always be possible or are unreliable guides for well targeting where the geothermal reservoir is concealed or structurally offset from the surface discharge area.

We are also evaluating the use of crosshole geophysics to determine whether a major steeply-dipping fracture zone has been missed by drilling. If a suitable technique can be developed, it would be enormously useful for planning directional re-drilling of marginal holes.

This paper will cover three topics:

- 3-D Gravity Inversions
- Self-Potential
- Surface-to-Borehole and Crosshole EM Tomography

Three-Dimensional Gravity Inversions

A 3-D computer code and methodology have been developed to extract potentially revealing information from gravity data (Goldstein and Carle, 1986; Carle and Goldstein, 1987; Carle, 1988). The method of analysis has been applied to data from two geothermal fields. In both cases the 3-D structural/density analysis reveals more information than we expected on fault locations, although in one case the information argues against a permeable reservoir region associated with the faults.

East Mesa Geothermal Field

The East Mesa, California, geothermal field has long been viewed as a classic model for a simple fault-charged reservoir (Goyal and Kassoy, 1981). However, there is only weak surficial evidence for a fault (Babcock, 1971) and the seismic evidence has been inconclusive (Majer et al., 1978).

The geologic model calls for thermal fluids to ascend along a steeply-dipping fault zone and then flow laterally into an aquifer. On the basis of studies of cores and chips from early wells drilled by the U. S. Bureau of Reclamation, the fault zone seems to have experienced repeated episodes of self-sealing followed by earthquake-induced reopening. The resulting gravity high, nearly coincident with the heat flow high, was commonly believed to reflect densification of the fault zone due to fracture filling and hydrothermal alteration of the sediments. To examine this hypothesis more carefully, we tested our newly developed 3-D gravity inversion code on a discrete Bouguer gravity anomaly which we assumed was caused only by densification of the fault zone. The methodology resulted in an image of the densified zone, whose upper surface is shown in contour form in Fig. 1. The shallowest parts of the densified zone appear as a north-south trending ridge and correlate well with the highest present-day subsurface temperatures. This would indicate that our model is basically correct and that most of the gravity anomaly is due to youthful hydrothermal conditions. The small northeast and southeast lobes of the density anomaly do not seem to correlate with the temperature anomaly. There could be several reasons for this, e.g.,

1. the lobes are remnants of older, and now colder, parts of the hydrothermal system,
2. the lobes are artifacts of data error or erroneous assumptions in the model, and
3. there is insufficient thermal data to exclude a possibility that a correlation exists between temperatures and the density lobes.

This approach to mapping the principal conduits for fluid flow seems to be applicable to porous sediments that have

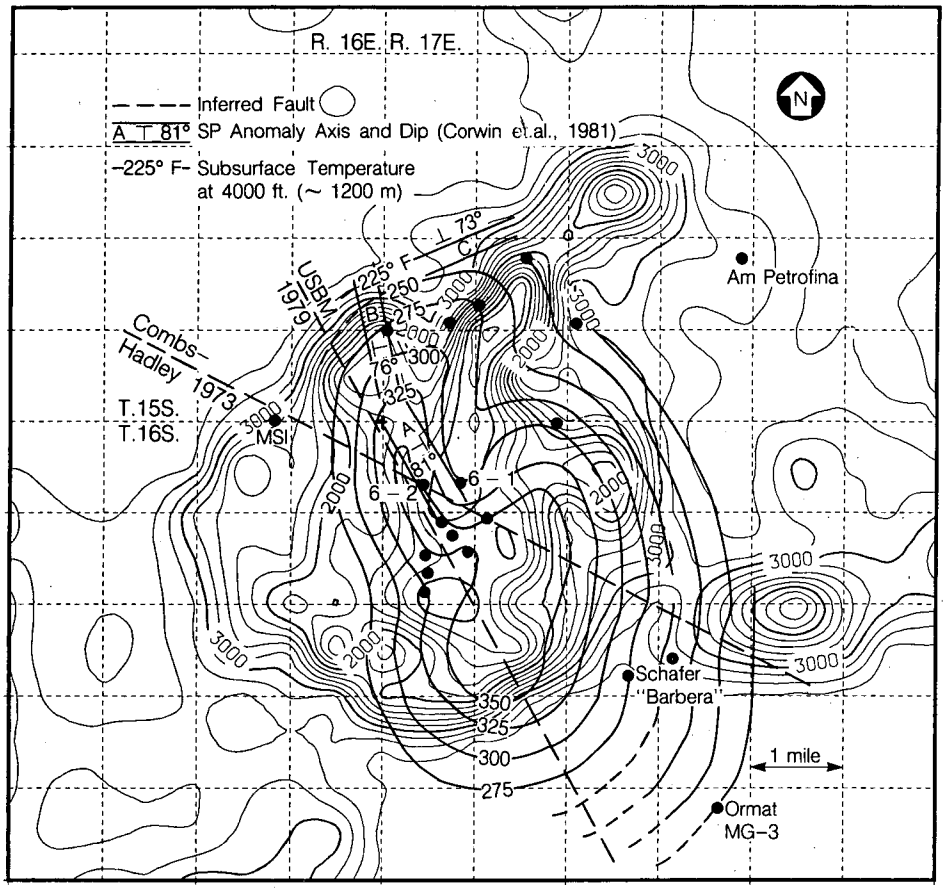


Figure 1. Contour image of the densified zone at the East Mesa geothermal field based on a 3-D inversion of the Bouguer anomaly. Contour units are in meters below the surface. The inversion was controlled using density information from well 6-1. The inferred fault denoted as USBM1979 is actually the fault first identified by means of aerial infrared photography (Babcock, 1971). Solid dots: wells.

experienced repeated and prolonged periods of hydrothermal activity. It is interesting to note that the strike of the self potential (SP) anomaly and the inferred fault direction (Babcock, 1971) both trend about N 30° W, not in the north-south direction of the density ridge. However, one can clearly see in Fig. 1 that the density anomaly does have a weaker secondary trend that matches the N 30° W strike of the other geophysical anomalies. Perhaps the principal stress directions have changed with time; the minimum stress direction might have rotated from E-W to N 60° E since the initial phase of faulting and hydrothermal activity.

Long Valley Caldera Fault Structures

Long Valley caldera, California, is a structurally complex volcanic environment in which there are several generations of faults. Among these are:

1. precaldera Sierran range-bounding faults, some of which continue to be active,
2. ring faults associated with cauldron block collapse, and
3. intracaldera extensional faults associated with post-caldera volcanic resurgence and extensional Basin and Range tectonics.

Many of the intracaldera faults have been identified and mapped over the last 20 years by means of careful surface mapping, aided by aerial photography, and a series of geothermal exploration holes drilled by industry and scientific holes drilled by DOE under the Continental Scientific Drilling Program. In spite of advances made toward understanding the structural complexities of the caldera, we do not yet have direct evidence for the principal faults that control the present-day hydrothermal upflow zone.

To discern caldera structure, we applied the 3-D inversion technique to an extensive gravity data set. The success in resolving caldera structure can be attributed to the completeness of the gravity coverage and the added information on caldera-filling lithology, stratigraphic thicknesses and rock densities provided by logs from seven holes, most of which bottomed in basement rocks.

Among the key structural features resolved by the 3-D gravity inversion is the approximate location of the inner ring-fracture zone (Fig. 2). There is some evidence from the 3-D gravity inversion that the inner ring-fracture zone may be a ring graben. This concept has been supported by drilling (Suemnicht and Varga, 1988; Eichelberger et al., 1988), but there is no evidence yet that these graben faults are the conduits for hydrothermal upflow in the west moat. It is conjectured that these conduits lie to the east of the graben because the permeability within graben structures should decrease

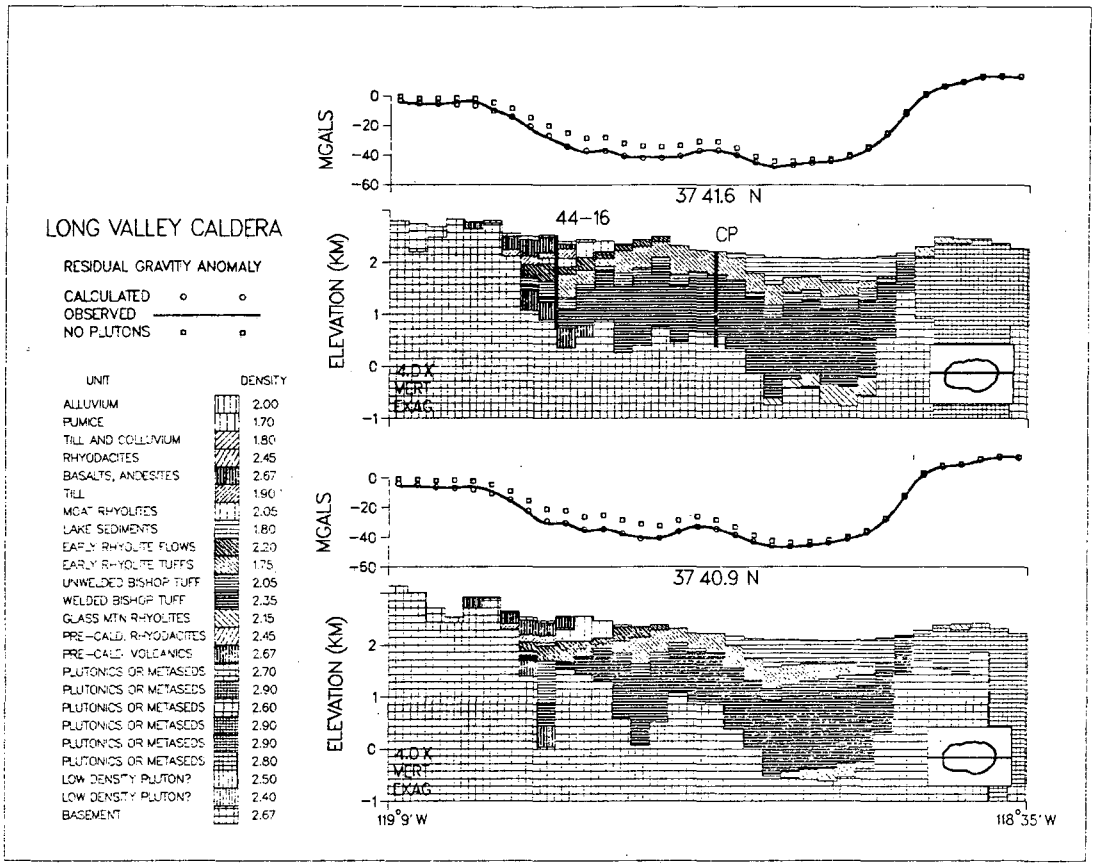


Figure 2. East-west cross-sections through the Long Valley caldera constructed from a 3-D inversion of the isostatic residual gravity data (Carle and Goldstein, 1987; Carle, 1988).

with depth unless there is a high rate of strain and the boundary faults dip at very high angles.

In summary, gravity analysis has resolved partially concealed ring (graben) faults, but these seem not to control the hydrothermal upflow in the west moat.

Self Potential and Reservoir Processes

The self-potential (SP) method is based on the fact that naturally occurring potentials observed on the earth's surface may often be related to electrochemical effects and other subsurface phenomena. Among the causes of SP anomalies over geothermal fields are:

- Electrokinetic; fluid flow due to a pressure gradient,
- Thermoelectric; heat flow due to a thermal source,
- Electrochemical; diffusion of chemical species due to a concentration gradient, and
- Oxidation-Reduction; a near-surface electrochemical cell set up at corroding well casing.

Due to the multiplicity of SP sources and the difficulty of modeling the electric flows in terms of geologic processes, the usefulness of SP as a diagnostic measurement has been in doubt. During the last ten years SP surveys have been made over many thermal areas, and SP anomalies were often found over fumaroles, hot springs, fault and fracture zones, etc. These results, coupled with laboratory studies and numerical modeling, confirm that the electrokinetic flow of ionic fluids in certain types of rocks and at appropriate pH and temperature conditions can result in SP anomalies of 50 - 300 mV. Thermal sources may only cause anomalies of 10 - 30 mV, while electrochemical noise is ± 5 mV in most areas.

It has also been noticed that geothermal production/injection activities alter the pre-production (natural state) SP anomaly at the few places where repeat surveys have been made. Is it possible, then, to draw inferences regarding subsurface conditions on the basis of changes in the SP anomaly? If so, can SP be used as a monitoring method to supplement wellhead and fluid enthalpy/chemistry data?

To explore these questions, we have analyzed a repeat SP survey made for DOE over the East Mesa field in late 1987. Under the DOE-CFE agreement, CFE has conducted a similar repeat survey over the Cerro Prieto field in Mexico. In these two Salton Trough areas the initial SP surveys were made in 1978. There are differences between the two areas, however. Whereas Cerro Prieto has experienced enormous brine extraction since 1978 with little reinjection, the brine production at East Mesa has been at least an order of magnitude less with total reinjection. We do not have yet the new Cerro Prieto SP data from CFE.

The East Mesa results show a few significant changes in the SP anomalies over and near the field (Fig. 3). The new data reveal a sharper negative anomaly (-35 mV) trending

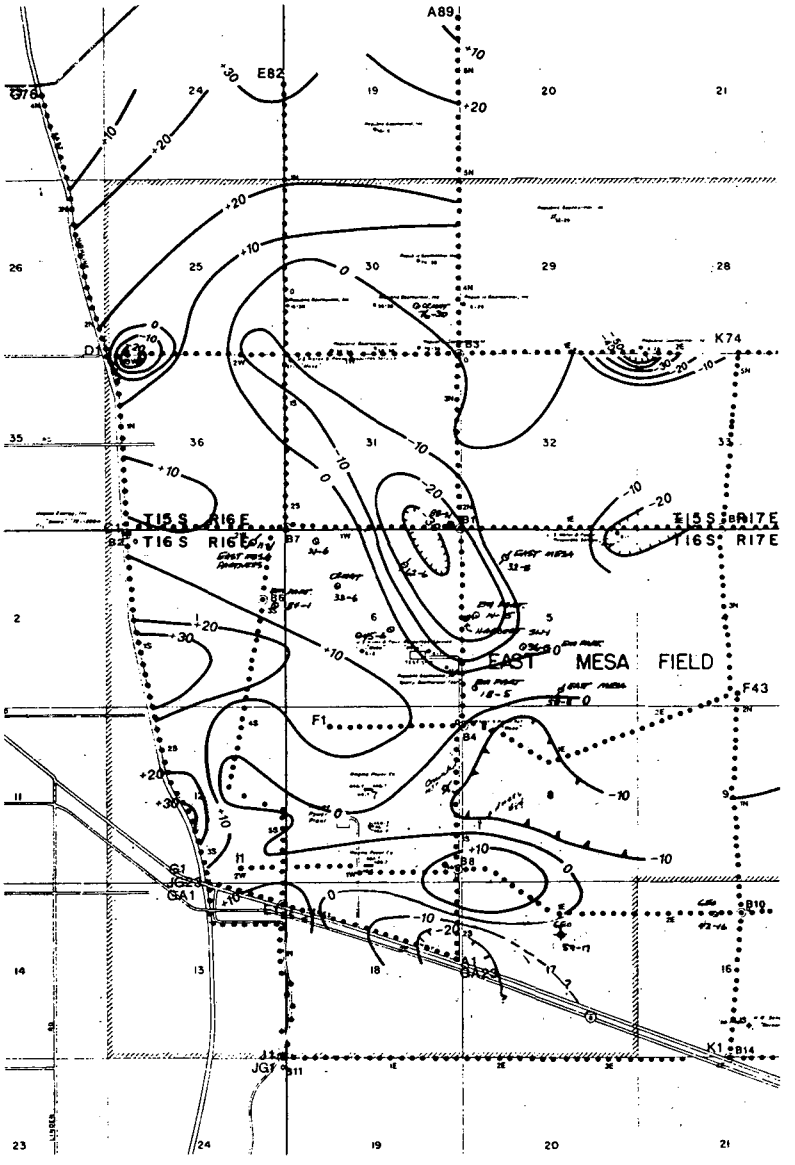


Figure 3. Smoothed self-potential anomalies over the East Mesa geothermal field, December 1987.

about N 30° W, oblique to the northerly strike of the principal gravity (densification) ridge but close to strike of the fault proposed by Babcock (1971) on the basis of oblique angle infrared aerial photography. Attempts to model the anomaly using pressure and temperature sources appropriate to the reservoir conditions (Goyal and Kassoy, 1981) proved to be unsatisfactory. The sharpness of the anomaly requires a very shallow source, one in the first few hundred feet of the surface. It would appear, then, that this SP effect may be due to shallow electrochemical reactions that occur along the fault trace, such as a fluid-fluid junction due to a permeability contrast across the fault.

Other interesting anomalies in the new data include

1 - a sharp low around well 18-28 which is probably due to casing corrosion,

2 - a sharp low at the west end of line D due to a pump on the East Highline Canal which is the western boundary of the survey area,

3 - irregular highs which may be due to fluid leakage from the Canal, and

4 - a very irregular pattern of dipolar anomalies (± 10 mV) at the south end of the production area and in the vicinity of production/injection wells completed in 1984-1986.

The analysis of the SP data continues.

Surface-to-Borehole and Crosshole Electromagnetic Tomography

The objective of this study has been to evaluate by means of numerical modeling the use of surface-to-borehole and crosshole (EM) electromagnetic tomography for detecting and characterizing a conductive fracture zone between two holes (Zhou et al., 1986; 1987; 1988; Morrison et al., 1988). Distinct from approaches followed by other workers who have focused their attention to radar frequencies or to dc

methods, our studies encompass the audiofrequency range (100 Hz to 20 kHz). Among the reasons why the audiofrequency range is being considered are:

1. the depth of penetration of these waves is much greater than at radar frequencies,
2. the waves interact well with a conductive fracture zone, and
3. there already exists a wide variety of geophysical hardware that can be used in a prototype system.

The basic assumption of the hypothetical geologic model is that there exists one or more steeply dipping tabular (or sheet-like) fracture zones missed by drilling (Fig. 4). A transmitter, either a grounded vertical electric dipole (GVED) or a vertical magnetic dipole (VMD) is lowered into one hole, while an induction coil magnetic detector is lowered into a second hole. The GVED would be useful in open holes and in rocks whose resistivities are not over 100 ohm · m. The VMD may have application in both cased holes and in higher resistivity rocks.

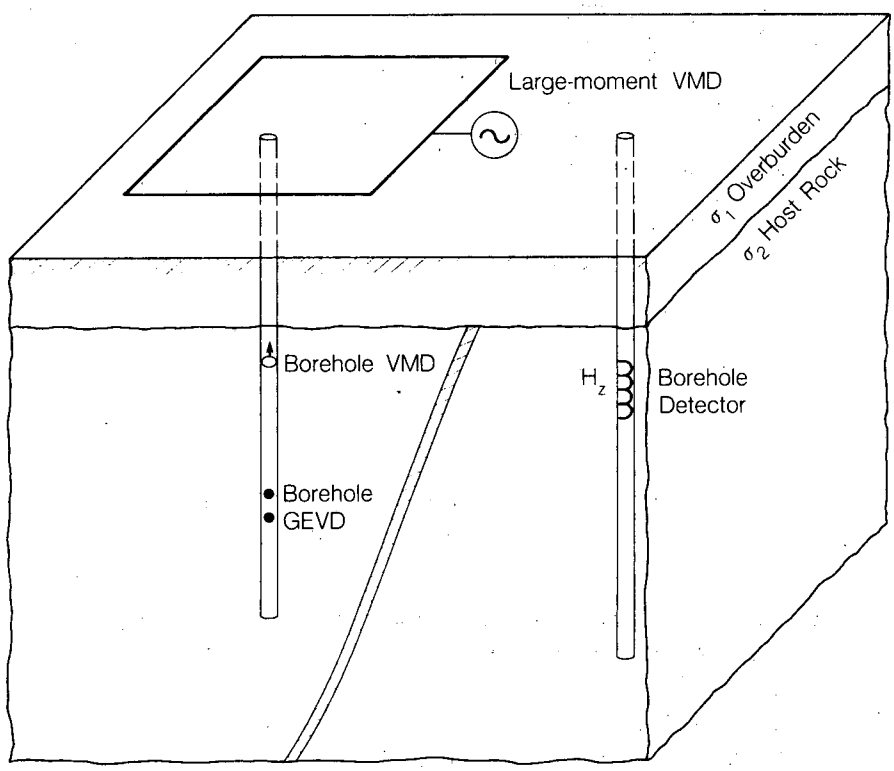


Figure 4. Schematic of the surface-to-borehole and crosshole EM techniques being evaluated numerically.

At this time we have completed a set of forward model calculations for the surface VMD source and for the downhole GVED and VMD sources. The code has been expanded to include multiple fractures.

Our current work is centered on the crosshole method, and it involves inversion of the EM data to map conductive areas between holes. A 2-D inversion code using diffusion tomography has been successfully tested using numerically generated data. What this means is that, different from the ray path approaches used in dealing with seismic or radar frequency waves, the governing equations specify that the field (signal) at each receiver point is affected by every volume element in the space between the two holes. To simplify the problem we also assume that the fracture zone is a weak scatterer; it only mildly perturbs the primary field (the so-called Born approximation from quantum mechanics). Thus far tests of the code verify that the dipping fracture zone can be imaged (Fig. 5). We do not yet have a code that can be applied to 3-D sources and 2-D conductors. Such a code is achievable if the proper approximations are made.

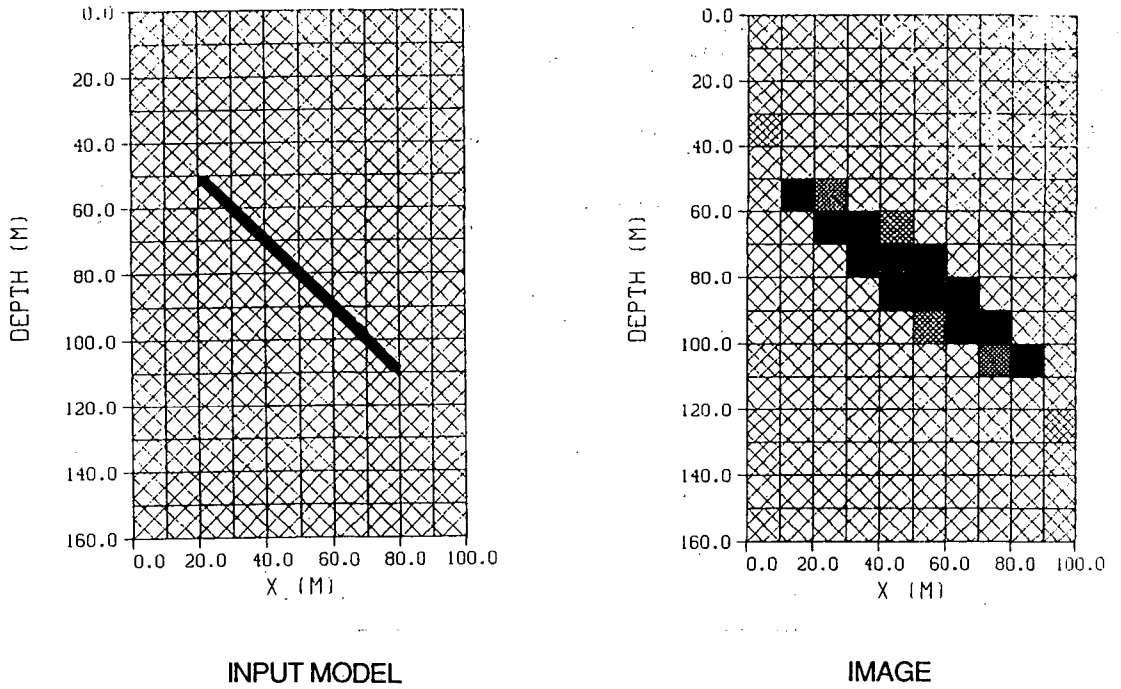
Our present plans are to test crosshole techniques at a non-thermal but well characterized site. For this we are looking for a suitable test site and for an industrial partner.

Acknowledgements

This work is supported by the U.S. Department of Energy, Office of Renewable Technology, Division of Geothermal Technology under Contract No. DE-AC03-76SF00098.

References

Babcock, E. A., 1971, Detection of active faulting using oblique infrared aerial photography in the Imperial Valley, California: *in* Rex., R. W., et al., Cooperative



Background conductivity σ_l =0.01/ohm-m | Frequency f= 5000 Hz | Fracture conductance τ = 0.1 S | 32 sources 32 receivers

Figure 5. A 2-D numerical example of EM imaging of a conductive fracture zone between two holes. The image on the right was obtained by means of diffusion tomography.

geological-geophysical-geochemical investigations of the geothermal resources in the Imperial Valley area of California, Univ. Calif., Riverside, **UCR/IGPP-71-2.**

Carle, S. F., 1988, Three-dimensional gravity modeling of the geologic structure of Long Valley caldera: *J. Geophys. Res.*, **93**, in press.

Carle, S. F. and N. E. Goldstein, 1987, Gravity and fault structures, Long Valley caldera, California: *Geoth. Res. Counc. Trans.*, **11**, 327-332.

Eichelberger, J. C., T. A. Vogel, L. W. Younker, C. D. Miller, G. H. Heiken, and K. H. Wohletz, 1988, Structure and stratigraphy beneath a young phreatic vent: South Inyo crater, Long Valley caldera, California: *J. Geophys. Res.*, **93**, in press.

Goldstein, N. E. and S. F. Carle, 1986, Faults and gravity anomalies over the East Mesa hydrothermal-geothermal system: *Geoth. Res. Counc., Trans.*, **10**, 223-228.

Goyal, K. P. and D. R. Kassoy, 1981, A plausible two-dimensional vertical model of the East Mesa geothermal field, California: *J. Geophys. Res.*, **86**, 10719-10733.

Majer, E. L., 1988, Seismological investigations in geothermal areas (this volume).

Majer, E. L., T. V. McEvilly, B. Schechter and N. E. Goldstein, 1978, Section 2: Seismicity *in* Howard, J. H. et al., Geothermal resource and reservoir investigations of U. S. Bureau of Reclamation leaseholds at East Mesa, Imperial Valley, California: Lawrence Berkeley Laboratory report **LBL-7094**, 33-55.

Morrison, H. F., N. E. Goldstein, T. Asch and Q. Zhou, 1988, Borehole electrical techniques in reservoir geophysics (abstr.): to be presented at the SEG/EAEG Reservoir Geophysics Workshop, Dallas, 31 July - 3 August 1988.

Suemnicht, G. A. and R. J. Varga, 1988, Basement structure and implications for hydrothermal circulation patterns in the western moat of Long Valley caldera, California: *J. Geophys. Res.*, **93**, in press.

Zhou, Q., K. H. Lee, N. E. Goldstein, H. F. Morrison and A. Becker, 1986, Fracture detection using a grounded subsurface vertical electric dipole: Lawrence Berkeley Laboratory report LBL-21985, 29 p.

Zhou, Q., K. H. Lee, N. E. Goldstein, H. F. Morrison and A. Becker, 1987, Fracture detection using subsurface electromagnetic techniques: Lawrence Berkeley Laboratory report **LBL-22614** (*in* Farmer, I. W. et al., eds., 28th Symposium on Rock Mechanics, Univ. Arizona, A. A. Balkema, Rotterdam, 5-17).

Zhou, Q., N. E. Goldstein and A. Becker, 1988, Crosshole electromagnetic responses of multiple thin conductors (extended abstr.): to be presented at the Soc. Expl. Geophys. Ann. Meeting, Anaheim, Calif., 30 October - 3 November 1988.

MAGNETOTELLURICS IN DEEP GEOTHERMAL EXPLORATION: APPLICATION TO THE LONG VALLEY MAGMATIC SYSTEM

Philip E. Wannamaker

University of Utah Research Institute, Earth Science Laboratory
391 Chipeta Way, Suite C, Salt Lake City UT 84108

ABSTRACT

The application of magnetotellurics (MT) in geothermal exploration often has been disappointing due to a lack both of high-quality data and of reliable interpretations. Primarily under DOE support, we have developed a research MT system incorporating a remote reference and sophisticated real-time statistical processing which yields the very high quality data needed to resolve subtle features in complex geologic environments. Also, we have produced uniquely versatile two- and three-dimensional interpretation algorithms appropriate to geothermal systems, and have made the algorithms available to others. A key theoretical contribution from our MT computer simulations is an understanding of the utility of 2D interpretation approaches for data taken over 3D prospects. Specifically, the transverse magnetic (TM) mode must be emphasized since it is relatively robust to departures from the 2D assumption.

In Long Valley caldera, we have collected twenty-four high-quality MT soundings with support from the DOE/GTD/-Magma program. Our data set reveals a rich variety of conductivity structures which relate to the evolution and present state of the Long Valley system. These include conductive layers on the order of 1 km deep from Clay Pit to the east wall of the caldera, beneath the axial graben of Smokey Bear Flat, and under the west moat. Resistive, probably crystalline basement at high levels is apparent in a central block from the center of resurgence to Clay Pit well. Most intriguing is a subtle anomaly in the transverse electric mode impedance phase which is suggestive of a deep conductive axis centered beneath the axial graben and resurgent dome. A finite element conductivity cross section has been derived for the upper three kilometers of the caldera and modeling is in progress for the deeper portions of the system.

INTRODUCTION

Twenty-four high-quality magnetotelluric (MT) soundings have been collected by UURI with its own instrumentation across Long Valley caldera with support by the DOE/Magma program (Figure 1). The purpose of MT observations in this environment is to gain control of upper crustal conductivity structure, and to ascertain the presence of any conductive, deep hydrothermal or magmatic system (Wannamaker, 1986). The data set to date is the result of two field excursions, one in late November and early December, 1986, and another in late September and early October, 1987. This project is ongoing.

Reconnaissance electrical geophysics together with gravity and refraction seismic surveys suggest substantial upper crustal conductances especially in the east but also in the west and south moats (reports in Goldstein, 1987). These are due mainly to faulted and altered volcanic stratigraphy which in large part rests disconformably on plutonic Sierran basement (Hill et al., 1985). Bipole-bipole apparent resistivities, telluric ellipse orientations, faulting, and gravity all indicate a NNW structural trend on average beneath our MT profile. Our soundings thus are processed and displayed using a fixed N20°W x-axis to facilitate two-dimensional modeling.

We have collected and interpreted MT data in recent years across the Long Valley Magmatic complex, the Juan de Fuca subduction system and Cascades Range in Oregon, and the Basin and Range-Colorado Plateau transition in southern Utah. These projects have been supported by both DOE and NSF. Our experience in these diverse environments has affirmed our theoretical concepts on the interpretation of MT in heterogeneous terranes and also has underscored the need for very precise field measurements.

OBSERVED DATA

Our data set is introduced with example sounding curves which demonstrate the subtlety of some of the anomalies and convey the statistical reliability of our data.

Towards the eastern portion of the line, the soundings for both modes detect a conductive layer at periods around 0.2 s (Figure 2). The layer is deepest in

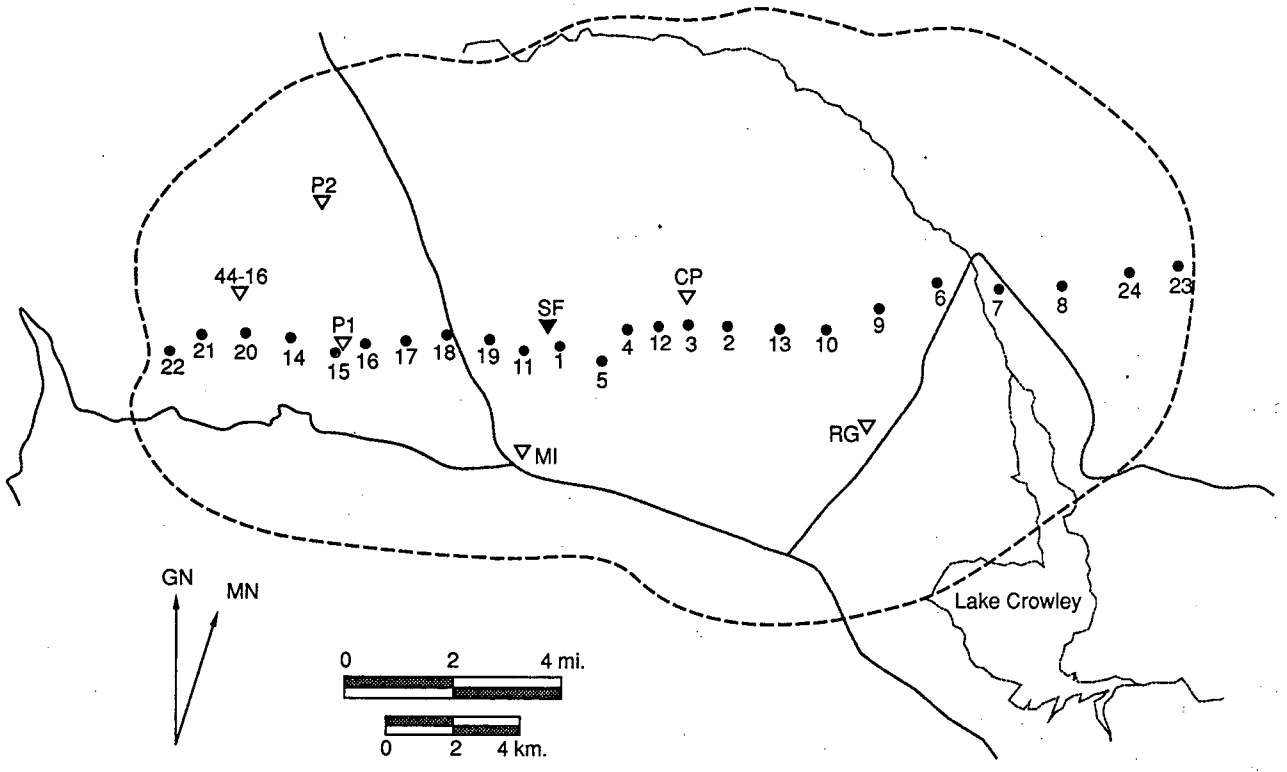


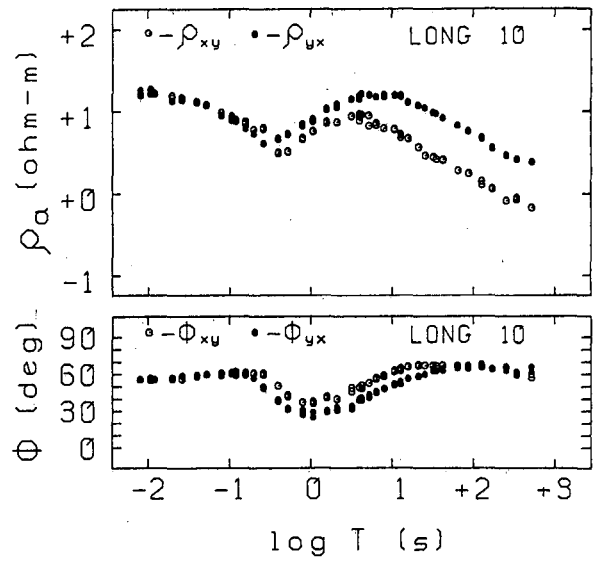
Figure 1. Site map for magnetotelluric soundings measured by UURI within Long Valley caldera. Several drill-hole locations are plotted and Santa Fe Geothermal Co. well pad is denoted by SF. Dashed curve traces caldera outline.

the east and comes to the surface and ends at site 2 about a mile SE of Clay Pit. This occurs approximately at the NW extension of the Hilton Creek fault zone as interpreted from previous bipole-bipole work by Stanley et al. (1976). Our most recent data indicates that this layer ends between our easternmost two sites (24 and 23) and so is confined to the caldera.

To the west over the resurgent dome, near-surface resistivities increase with the presence of younger volcanics (Figure 3). For stations only over the axial graben of the Smokey Bear Flat area (sites 11 and 17 to 19), however, a distinct conductive layer affects both modes around 1 s period (Figure 3). Our high data quality has allowed resolution of this discrete unit where previous electrical surveys have implied only a broad zone of low resistivity in this area. In the west moat (e.g., site 20, Figure 3), a relatively shallow conductive layer occurs as has been noted previously in publicly-released commercial MT and time-domain (TDEM) surveys and which has been modeled extensively by Park and by Nordquist (Goldstein, 1987).

Also in the central portion of the caldera, a deep conductive axis trending NNW is suggested especially by the impedance phase data at the middle and longer periods (Figure 3). The manifestation occurs exclusively in the nominally TE mode data (ρ_{xy}, ϕ_{xy}), verifying both the NNW trend and our selection of a fixed orientation for data interpretation. That the TE mode alone is affected suggests that the causative structure is of narrow E-W extent relative to its depth, or that perhaps the conductivity here is anisotropic. The anomaly is quite subtle and would be missed without very precise measurements. The TE phase remains anomalous to probably 1000 s in this area but is observed to diminish again at long periods beneath the west moat (site 20 for instance).

The data we have collected is summarized in pseudosection form (Figures 4 and 5). The shallow conductive layers in the east and west moats and a very resistive basement especially south of Clay Pit are clear in both TE and TM modes. The very flat character of the TM phase ϕ_{yx} at long periods over the



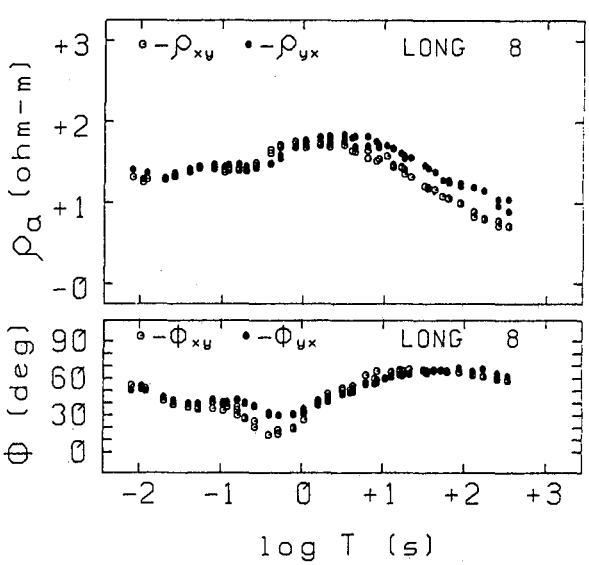
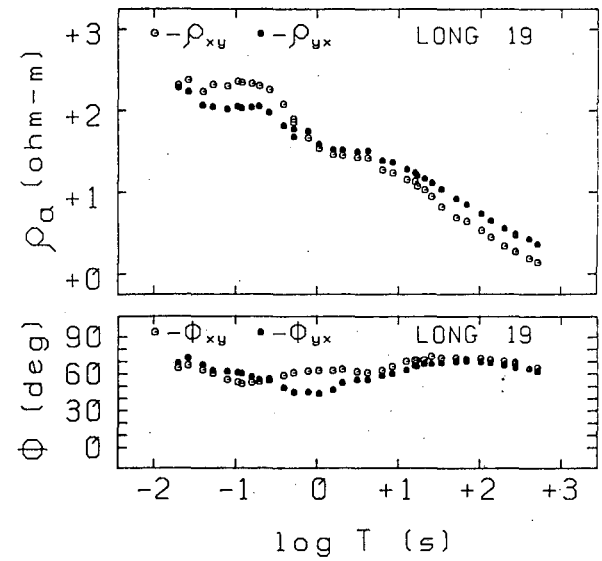


Figure 2. Apparent resistivity and impedance phase sounding curves at sites in the eastern half of the caldera. A shallow conducting layer is manifest near 0.1 s period which extends from the projection of Clay Pit to the eastern caldera wall.



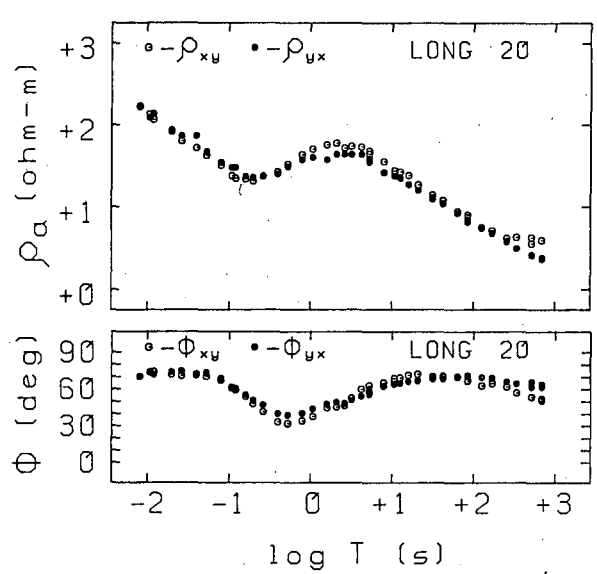


Figure 3. Apparent resistivity and impedance phase sounding curves at sites over the axial graben and western moat of the caldera. A conducting layer affects the sounding curves over the graben at about 1 s period while the TE phase in this area shows a slight anomalous high at long periods especially relative to soundings east and west. A shallow conductive layer affects all our soundings in the west moat.

eastern half of the caldera (Figure 4) suggests uniform resistivity in the middle and lower crust to E-W current flow, or at least inhomogenities whose E-W extent is substantially less than their depths. The TM mode also indicates a fundamental transition beneath station 11 at the east boundary of the central graben of Smokey Bear Flat. To the west of this, greater thicknesses of high conductivity are manifest at least in the upper crust.

Higher conductivity may exist also in the deep crust of the west in accordance with the somewhat higher values of ϕ_{yx} and ϕ_{xy} around 100 s here. Evidence for the NNW-trending deep conductive axis stated above lies in the high in ϕ_{xy} from 10 to 1000 s period centered below the axial graben. Tentatively, we argue for an isolated axis at some depth rather than the anomaly being due to a conductor which is laterally extensive throughout the west moat and in the northern portion of the caldera, as modeled by Park (in Goldstein, 1987). This is because the two entities occupy different lateral positions and are so widely separated in period.

TWO-DIMENSIONAL MODELING

Since we have a single profile of MT stations across the caldera, much of our interpretation must be based on a two-dimensional analysis. This is a very complex geoelectric environment so that a 2D approach must be justified by 3D MT simulations appropriate to the area. Model studies by Wannamaker et al. (1984) have shown that 2D modeling of the TM mode data across elongate 3D structures can yield an accurate conductivity cross section. The data profile does not need to be close to the center of the body for this to be accomplished. When surficial inhomogeneity is substantially more complex than this simple model, 2D TM interpretation yields a cross section which may be somewhat incorrect in its surficial features but which represents accurately the regional conductivity structure provided the regional structure itself is not arbitrarily 3D (Wannamaker, 1985). The TE mode remains tough to work with because the end effects of 3D structures can be so extreme (Wannamaker et al., 1984).

In light of the previous discussion, we commence our interpretation of our MT data profile with trial-and-error simulation of the TM mode response. For this we use the finite element algorithm of Wannamaker et al. (1986) which can model arbitrary conductivity cross sections including topography. A preliminary cross section of the upper three kilometers in Long Valley caldera

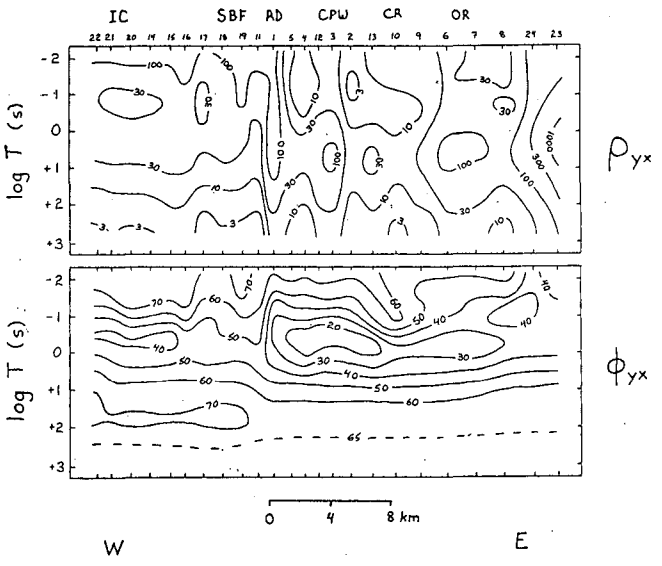


Figure 4. Pseudosections of TM mode apparent resistivity and phase for our profile across Long Valley caldera. Most evident is a very resistive basement just east of the center of resurgence as well as a major boundary at the east margin of the axial graben with greater volumes of upper crustal conductive material to the west. Important landmarks include the Inyo Craters trend (IC), Smokey Bear Flat (SB), Clay Pit Well (LCP), and the Owens River (OR).

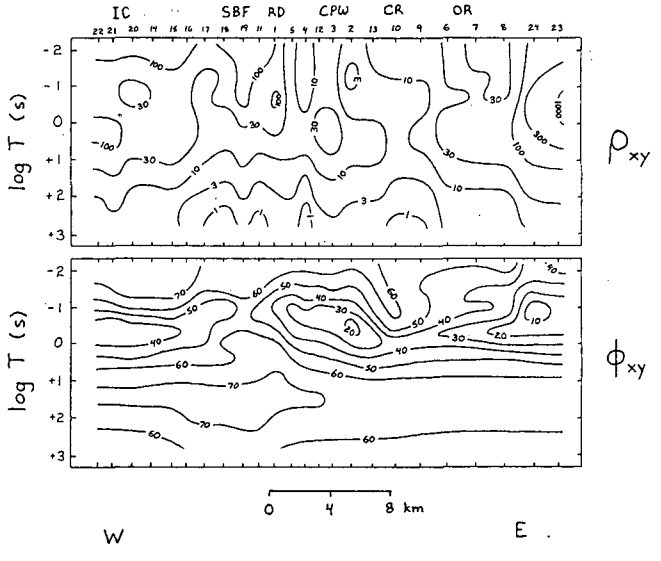


Figure 5. Pseudosections of TE mode apparent resistivity and phase for our profile across Long Valley caldera. There are several features in common with the TM mode sections but note also the high in ϕ_{xy}, and the anomalous decrease in ρ_{xy}, at periods greater than 10 s below the axial graben.

appears in Figure 6. This results primarily from modeling the data of 1 s period and shorter. Topographic variations have been incorporated directly in the finite element mesh and are important locally.

In Figure 6, the upper crustal conductivity layering apparent in the observed data is quantified. The conductor several hundred meters deep below the west moat corresponds to an increase in clay alteration in post caldera volcanics overlying the Bishop Tuff (Nordquist, in Goldstein, 1987). Beneath Smokey Bear Flat, the conductor at 1.3 km depth may correlate with conductive graphitic metasediments in a roof pendant of Sierran batholithic rocks (Park, in Goldstein, 1987). These were observed at a similar depth in the M-1 hole drilled about 2 miles south of our line. Note that the two conductors just described are connected electrically beneath sites 16 and 17 even though they appear to be unrelated geologically. This connection, necessary to give the response below Smokey Bear Flat, may have resulted from alteration along a major boundary fault of the axial graben during eruption of post-caldera moat rhyolites along this trend (Hill et al., 1985).

Below station 1, about 0.75 km SE of the Santa Fe geothermal well pad (Figure 6), there is a sharp break in upper crustal resistivity with a shallow level, very resistive horst to the east. This has been implied from other electrical surveys, though not nearly to this detail. The depth to resistive basement appears less than 500 m from sites 5

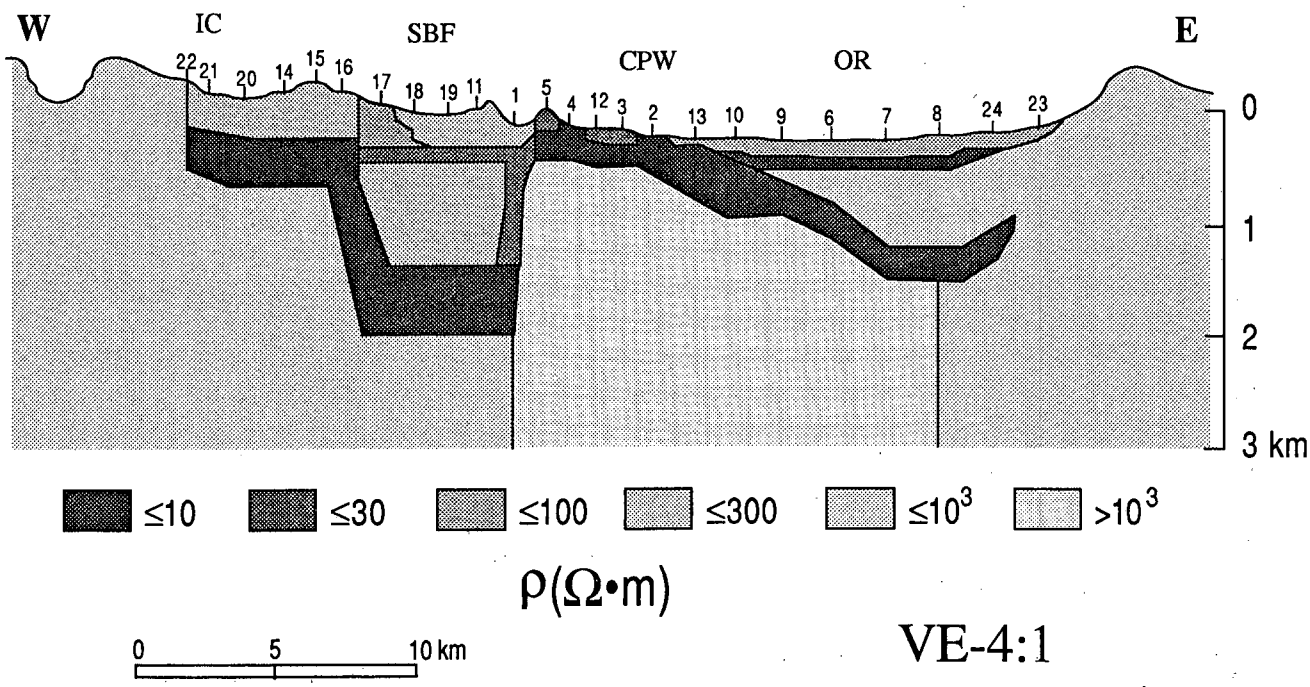


Figure 6. Preliminary finite element cross-section for our MT stations across Long Valley caldera. Principal structures include conductive layers (dark) below the west moat, the axial graben, and east from the subsurface Hilton Creek fault zone. Also note the very resistive, shallow horst beneath the center of the caldera. This model is based on the TM mode data at periods of 1 s and shorter. Important landmarks include the Inyo Crater trend (IC), Smokey Bear Flat (SBF), Clay Pit Well (CPW), and the Owens River (OR). detail.

through 3. Drilling at Clay Pit Well shows the top of the Bishop Tuff to be at these levels here (e.g., Hermance, in Goldstein, 1987), confirming that the tuff as a whole is resistive. Eastward starting at site 2, which is approximately on line with the NW extension of the Hilton Creek fault zone, appears another substantial layer-like conductor which diminishes in conductance and finally ends near the east wall of the caldera. Refraction seismic data (by Hill and others) suggest that this layer also resides near or on top of the Bishop Tuff. Perhaps the conductive material here, beneath the west moat volcanics, and along the margins of the axial graben in Figure 6 represents hydrothermal alteration and sediments associated with implacement of post caldera moat rhyolites.

Below about 2 km depth we show only resistive basement rocks due to the short period range of data modeled so far. In deriving deeper portions of the conductivity section, we will continue to emphasize 2D modeling of the TM mode data. It will be interesting to verify whether the somewhat higher values of ϕ_{yx} around 100 s over the west moat and axial graben indicate higher conductivity in the deeper crust of this area. We do not observe a distinct anomaly coincident with the Inyo Craters trend. However, making sense of the subtle high in ϕ_{xy}, the TE mode phase, at long periods over the axial graben and resurgent dome will be substantially more difficult, but it may be the most important from a deep geothermal standpoint. Within the conductivity cross section derived from the TM mode fit, additional deep structure may be emplaced in an attempt to fit low-frequency TE mode phase anomalies, without degrading the TM mode fit. Eventually, 3D simulations will probably be necessary to explain some important features of the data and we may face complex coupling between deep 3D structures and their host (eg., Newman et al., 1985).

FUTURE PLANS

A final field trip to the Long Valley is planned for this summer. Its purpose is to extend the profile outside the walls of the caldera and to increase sampling somewhat near the west margin of the axial graben. Extending the profile outside the caldera is required if we are to ascertain the conductivity contrast between caldera fill and host plutonic rocks and whether the deep conductivity within the collapse feature as a whole has been altered by caldera formation. Knowledge of this will be important in the interpretation of any deep conductivity within the caldera associated with the presence of a deep hydrothermal system or magma itself.

The geothermal significance of deep conductivity structure required by the data is the most important aspect of our research in Long Valley, but poses a difficult problem in itself. All probable effects of upper crustal structures have not yet been evaluated. However, if a sufficiently rigorous modeling effort indicates that anomalous conductivity exists quite deep in the system, say 5 km or more, I believe the case for a geothermal explanation will be strengthened. It is noted also that the long period anomaly in ϕ_{xy} is coincident in E-W location with recent models of P-wave velocity perturbations (Dawson et al., in Goldstein, 1987).

REFERENCES

1) Goldstein, N. E., editor, 1987, Proceedings of the symposium on the Long Valley caldera: a pre-drilling data review: Lawrence Berkeley Laboratory, report LBL-23940, 195 p.

2) Hill, D. P., Bailey, R. A., and Ryall, A. S., 1985, Active tectonic and magmatic processes beneath Long Valley caldera, eastern California: J. Geophys. Res., 90, 11,111-11,120.

3) Newman, G.A., Wannamaker, P.E., and Hohmann, G.W., 1985, On the detectability of magma chambers using the magnetotelluric method: Geophysics, 50, 1136-1143.

4) Stanley, W. D., Jackson, D. B., and Zohdy, A. A. R., 1976, Deep electrical investigations in the Long Valley geothermal area, California: J. Geophys. Res., 81, 810-820.

5) Wannamaker, P. E., 1985, Very low frequency magnetotelluric and dipole-dipole responses of three-dimensional thin-layer resistivity structure modeled using finite elements: Dept of Energy Rep. DOE/SAN/12196-14, 32 p.

6) Wannamaker, P. E., 1986, Electrical conductivity of water-undersaturated crustal melting: J. Geophy. Res., 91, 6321-6327.

7) Wannamaker, P. E., Hohmann, G. W., and Ward, S. H., 1984, Magnetotelluric responses of three-dimensional bodies in layered earths: Geophysics, 49, 1517-1534.

8) Wannamaker, P. E., Stodt, J. A., and Rijo, L., 1986, Two-dimensional topographic responses in magnetotellurics modeled using finite elements: Geophysics, 51, 2131-2144.

Physical and Chemical Rock Property Measurements in Geothermal Exploration and Reservoir Studies

Alan C. Tripp, Michele M. Lemieux, Phillip M. Wright, Joseph N. Moore, and Howard P. Ross

University of Utah Research Institute, 391 Chipeta Way, Suite C, Salt Lake City, UT 84108

ABSTRACT

Electrical geophysics has been used extensively in geothermal exploration to detect fracture systems and high-temperature brines which give rise to low resistivity zones. However, low temperature clay alteration can also cause a low resistivity zone. We suggest that the IP method can be used to distinguish a low resistivity zone caused by clay alteration from low resistivity zones arising from different causes. We have measured the induced polarization (IP) phase response of core from the Medicine Lake Burnt Lava hole 62-21 and from the Clackamas Thermal Gradient Hole #1. The core samples were weakly to moderately clay altered, with the alteration of low-temperature origin. We noted a direct relationship between the IP response of the samples and their degree of low-temperature alteration.

INTRODUCTION

The Earth Science Laboratory of the University of Utah Research Institute has begun a program of laboratory and in-situ measurements of the physical properties of rocks in an effort to better interpret geophysical measurements in geothermal areas. This paper will report on one project which we are currently pursuing in this area.

A PROBLEM AND A POSSIBLE SOLUTION

Electrical geophysical methods have been used extensively in geothermal exploration to detect resistivity anomalies. The most popular methods used have been DC resistivity, frequency-domain or time-domain electromagnetics and magnetotellurics. All of these methods have the common problem that low resistivities can be caused not only by fracture systems or by high-temperature brines, but by low-temperature clay alteration as well. Thus the physical nature of low resistivity geologic units detected by these methods must be deduced from the geometry of the geologic units. However, the induced polarization (IP) method is a possible means of distinguishing low temperature alteration from other sources of low resistivities without recourse to deductions based on geologic unit geometry.

Previous work in hydrothermal alteration suggests that clay and zeolite minerals with large numbers of exchangable cations occur predominantly in rocks altered at low temperatures. Since these clays and zeolites can give a significant IP response, we hypothesize that rock altered at low temperatures should have an IP response which is in general higher than the IP response of rock subjected to high temperatures. Therefore, the IP method can be used to narrow down the possible source of a low resistivity zone; something the other electrical methods can not accomplish.

NATURE OF THE IP RESPONSE

The induced polarization method detects the small electrochemical charge storage which some geological materials exhibit during electrical conduction. There are two types of geologic material which can have significant IP responses. One type consists of rock containing a mineral which has a large intrinsic electric conductivity, such as pyrite. In these materials, charge storage occurs at the interface between the conductive mineral and the pore water.

The second type of geologic material which has a significant IP response consists of rocks containing minerals which have a large cation exchange capacity, such as zeolites or clays. In these materials, charge storage involves the exchange cations which are displaced under the influence of an electric field.

MEASUREMENT OF THE IP RESPONSE

Figure 1 shows a possible electrode configuration for measurement of the IP effect of a region of earth. In the electrode array of this figure, current I is injected into the ground at the two electrodes to the left and the voltage V is measured across the two electrodes to the right. The current I can be a square wave, as shown in Figure 2 or a sinusoid as shown in Figure 3. If the current is

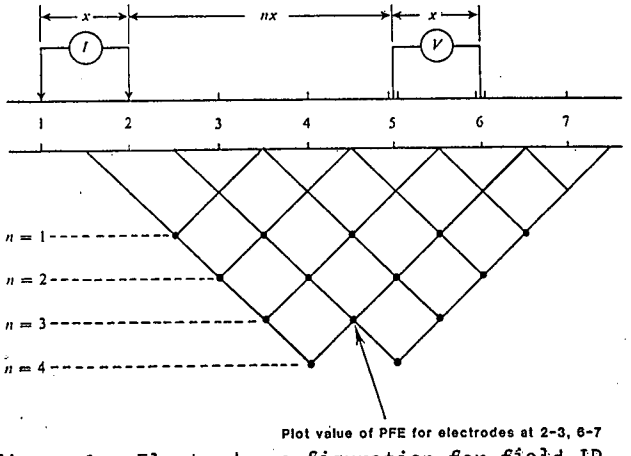


Figure 1. Electrode configuration for field IP measurements.

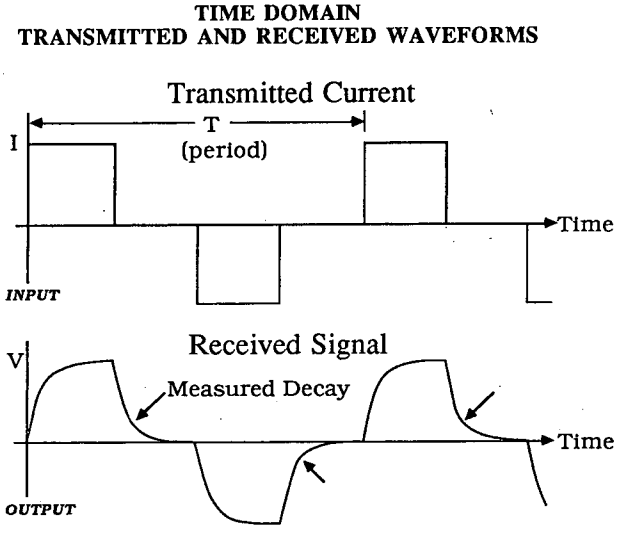


Figure 2. Time domain waveforms.

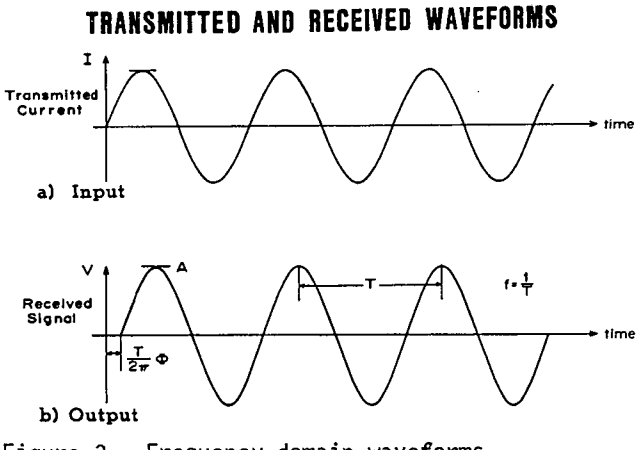


Figure 3. Frequency domain waveforms.

a square wave, then the measure of the IP effect of the material is the rate of decay of the received voltage after the transmitter current is switched off, as shown in Figure 2. If the current is a sinusoid, then the measure of the IP effect is the phase shift between the received voltage sinusoid and the current sinusoid, as shown in Figure 3.

LABORATORY MEASUREMENTS

We have made laboratory measurements of the IP response of core samples from two drill-holes in the Cascades, the Clackamas thermal gradient hole #1 (CTGH-1) and the Medicine Lake - Burnt Lava 62-21 hole, drilled by Phillips Geothermal. The core samples were saturated with an aqueous solution of the same salinity as was measured in fluid inclusions contained in the Burnt Lava core. The injected current was sinusoidal and hence we measured the phase shift between the injected current and the sinusoidal voltage in the receiver. The phase was measured over a frequency spectrum from 1/64 Hz to 256 Hz. Two sample phase spectra are shown in Figure 4. In future work we wish to correlate the shape of these spectra with the lithology and clay content of the samples. At present, however, we will be concerned only with the low-frequency asymptotes of these spectra.

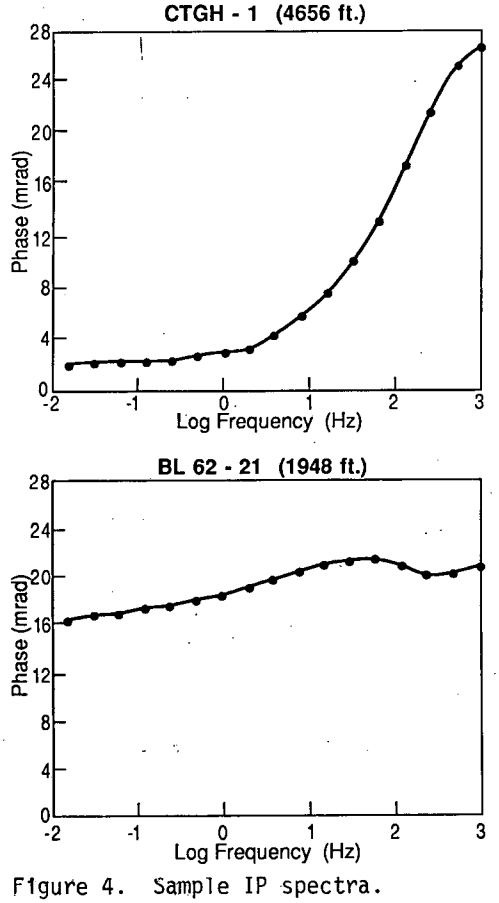


Figure 4. Sample IP spectra.

Figure 5 is a scatter-graph of the measured phase at 1/64 Hz of selected core samples versus the cation exchange capacity of the samples. We have divided the samples into groups I through IV on strictly empirical grounds. The samples in group I seem to fall on a straight line, as do the samples in groups II and III. The sole sample of group IV has some special properties which set it apart. Although we cannot attach any theoretical significance to the apparent linearity in each of the groups and cannot even prove that the linearity is not accidental, it is still interesting to search for common properties shared by the samples in each of the groups.

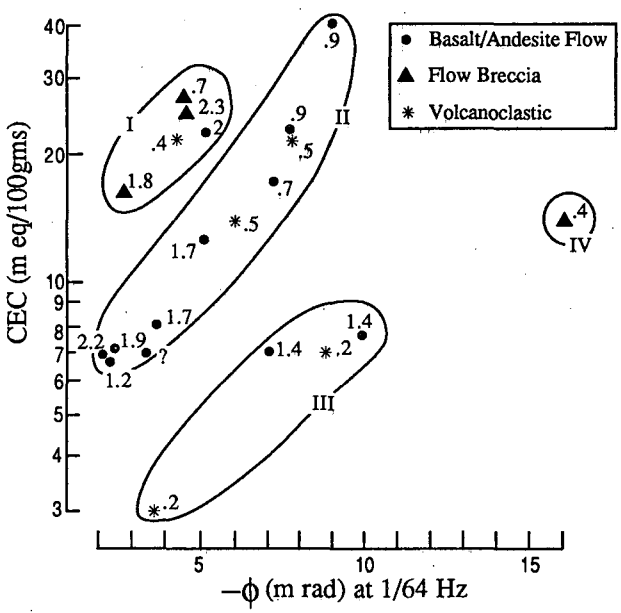


Figure 5. Scatter-graph of CEC vs. -ø. The numbers represent magnetic susceptibility (c.g.s) x10^3

All but one of the flow breccia samples belong to group I. The other two members of group I are samples from a volcaniclastic unit and a flow interior. The rocks of group I tend to have an altered rock matrix with continuous conduction paths throughout the rock. The amount of clay in the altered rock matrix is high, consistent with the high CEC values of the group. The comparatively low value of phase relative to the other groups is consistent with the observations of Vacquier et al. (1957), who noted that the IP response of rock can decrease as clay conduction paths become continuous. The magnetic susceptibility of group I rocks range from 0.4 x 10^{-3} to 2.3 x 10^{-3}, indicating a wide range of magnetite content.

The rocks of group II primarily come from basalt/andesite flow interiors. Zeolites in these rocks tend to be concentrated in vesicles, while the clays tend to be disseminated through the rock. The CEC values range from 6 meq/100gms to 40 meq/100gms, while the phase ranges from 2 mrad to 9 mrad. The magnetic susceptibility of group II rocks ranges from .5 x 10^{-3} to 2.2 x 10^{-3}, indicating a wide range of magnetite content.

Group III rocks were 50% volcaniclastics and 50% from flow interiors. The rocks in group III have phases which are much greater for a given CEC than the phases for rocks in groups I and II. This behavior would be consistent with the presence of semi-conducting minerals such as pyrite or magnetite. Examination of the samples indicates that pyrite is not present in amounts which exceed that in samples of groups I and II. Furthermore, the values of magnetic susceptibility indicate that magnetite is not present in amounts which exceed that in samples in groups I or II. However, examination of thin sections taken from the group III samples reveals higher contents of hematite. We conjecture that this hematite, which is not present in significant amounts in any of the other samples, is responsible for the position of the group III samples in the scatter-graph. The physical mechanism by which hematite would affect the measured CEC or the phase is presently undetermined.

The sole member of group IV is unique among the rock samples in possessing large amounts of zeolite lining interconnected vesicles. Pyrite is not present while the amount of magnetite, determined from the magnetic susceptibility measurements and from thin section observations, is small. The rock of group IV has the highest phase of any sample, but its measured CEC capacity is only moderate. Certainly, the high phase is consistent with the large amount of zeolite present in the rock, but the CEC value seems too low to be consistent with the amount of zeolites.

Figure 6 shows a scatter-graph of the resistivity of the rock samples versus the measured porosity. As we would expect, the resistivity tends to decrease as the porosity increases. The flow breccias form a reasonably tight cluster at high porosity and low resistivity values. The scatter of resistivity and porosity values for volcaniclastics is somewhat greater than that for the flow breccias. The scatter in resistivities and porosities for flow rocks is very large, apparently reflecting a large range in the number of

vesicles and their interconnections. The number beside each sample point is the measured CEC for that sample. There is a general increase in CEC as resistivity decreases and porosity increases. This correlation between resistivity, porosity, and CEC reflects the dependence of these quantities on the interconnections and surface area of rock exposed to hydrothermal fluids.

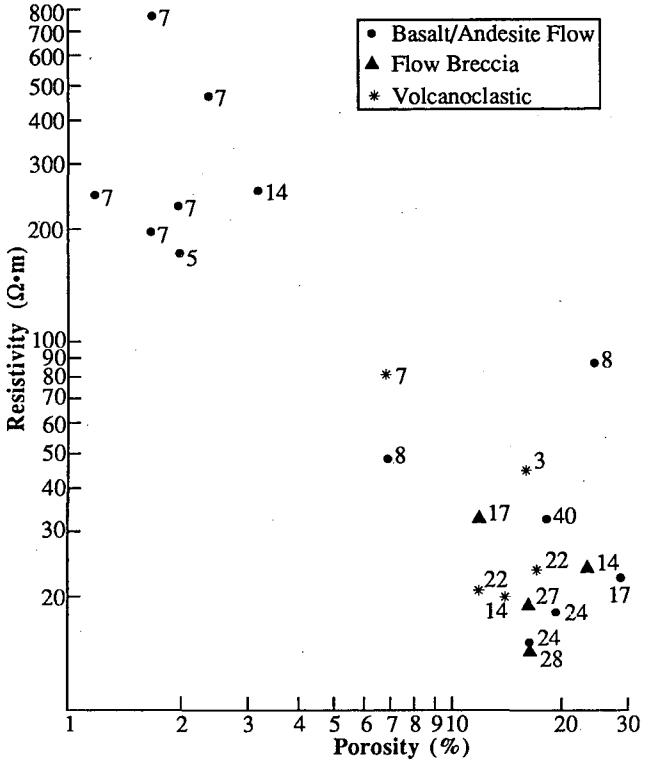


Figure 6. Scatter-graph of resistivity vs. porosity. The numbers represent CEC.

X-ray diffraction analyses are in progress. This is important because rocks containing the same weight percent of clays with identical CEC-s but different exchangeable cations can have vastly different induced polarization responses.

We have not yet examined the influence of temperature on the IP response. Vinegar and Waxman (1984) and Keevil and Ward (1962) report that for shaly sands the measured phase is almost constant over the temperature range of 25°C to 100°C. Vinegar and Waxman state that this is so because the equivalent conductance of clay exchange cations increases with temperature as rapidly as does the equivalent conductivity of the electrolyte. We hypothesize that the transport properties of the electrolyte in our samples will have a similar dependence on temperature and that the measured phase should not vary strongly with temperature up to 100°C. Also, we have not yet measured the IP response of Cascades rocks altered at high-temperatures. On the basis of previous work in hydrothermal alteration (Kristmannsdottir and Tomasson (1978); Hulen and Nielson (1986); Nielson, pers. comm.) we expect that the clay and zeolite minerals with the largest CEC values occur predominantly in rocks altered at lower temperatures. Hence we expect the IP response of altered rocks to decrease as the temperature of alteration increases. We will investigate this hypothesis in future work.

CONCLUSIONS

We have demonstrated that Cascades rocks with low temperature alteration do have IP responses which are often significantly above a background IP effect of 1-5 mrad. We have not yet demonstrated that the magnitude of the contrast between the IP response of low temperature rock and high temperature rock is sufficient to permit discrimination between the two in the field. We will continue our measurements on Cascades core in search of an answer to this question.

ACKNOWLEDGEMENTS

The work reported here was done under U. S. Department of Energy Contract No. DE-AC07-8512489. Ruth Kroneman did the chemical analyses for the CEC determination. David Langton helped with sample preparation. Kathryn Ruth typed the manuscript and Pat Daubner made the illustrations.

REFERENCES

1) Hulen, J. B., and Nielson, D. L., 1986, Hydrothermal alteration in the Baca geothermal system, Redondo Dome, Valles Caldera, New Mexico: J. G. R., v. 91, No. B2, pp. 1867-1886.

2) Keevil, N. B. and Ward, S. H., 1962, Electrolyte activity - its effect on induced polarization: Geophysics, v. 27, p. 677-690.

3) Kristmannsdottir, H., and Tomasson, J., 1978, Zeolite zones in geothermal areas in Iceland, in Natural Zeolites: Occurence, Properties, Uses: L. B. Sand and F. A. Mumpton, Ed., Elmsford, N. Y., Pergamon.

4) Vinegar, H. J. and Waxman, M. H., 1984, Induced polarization of shaly sands: Geophysics, v. 49, no. 8, p. 1267-1287.

RESERVOIR ENGINEERING

Session Chairpersons

Ron Schroeder
(Berkeley Group, Incorporated)

Sabodh Garg
(S-CUBED)

HIGH TEMPERATURE INSTRUMENTATION

Leonard E. Duda
Sandia National Laboratories

ABSTRACT

In the next several years the need for high temperature instrumentation will grow as drilling into high temperature regimes increases for both the Continental Scientific Drilling Program and the Magma Energy Extraction Program. Sandia National Labs. has developed some high temperature downhole instruments over recent years and will continue the development of instruments for the new drilling programs underway. In this paper, past efforts in high temperature instrumentation, current activity in this area, and future plans for high temperature instrumentation are presented. Over the past five years, Sandia has modified a commercial acoustic borehole televiewer for high temperature use in geothermal wells and developed five high temperature instruments for use in the Salton Sea Scientific Drilling Project. These five SSSDP tools were completely self-contained and all were designed to operate with a slickline cable.

Because of the 300°C temperature limitation of the insulation on commercial logging cables, we have concluded that self-contained electronic tools having an internal memory for data storage are the best current approach for high temperature (>300°C) logging. Current activity by Sandia in this area includes modifications to the digital temperature/pressure tool developed for the SSSDP to allow the tool to simultaneously measure external temperature and temperature-compensated external pressure. In support of the Baca Flats well, on which drilling will begin in July 1988, a 2 inch diameter downhole temperature probe capable of surviving to 400°C is being developed in cooperation with Geophysical Research Corp. of Tulsa, Oklahoma.

Future instrumentation plans include the development of modular/memory controller systems. These instruments will use interchangeable memory units and be capable of both wireline and slickline operation. Very high temperature instruments, i.e. for temperatures approaching 500°C, must be developed for the logging of the well drilled for the magma energy extraction program.

INTRODUCTION

For several years, the Geothermal Research Division at Sandia National Laboratories has been investigating and developing downhole instruments for making measurements in the severe environments encountered in geothermal wells. These harsh conditions include high temperatures of the wellbore fluid, corrosion, and scaling caused by this fluid. In the future, as drilling proceeds into deeper and hotter wells, the present generation of downhole instrumentation will no longer be adequate.

High temperatures in geothermal wells put several constraints on the type of instrumentation which may be used in these wells. Most logging instruments cannot function above 225°C. A practical upper limit for standard electronic components is 125°C. Some specialized electronics suitable for higher temperatures are available, but these are costly and are usually not readily obtainable. Communicating with the tool in the wellbore is also a problem. Electrical wireline cable is limited by the maximum use temperature of its insulation. TFE-insulated cable may be used up to about 300°C, but a practical limit for this type of cable is probably 20°C less. In addition to the wireline cable, the cable head also limits the high temperature application of wireline tools. A maximum upper temperature limit for typical cable heads is 250 to 275°C. The constraints listed here show that in the high temperature logging regime, which we define as temperatures above 300°C, standard logging tools and wireline methods can no longer be used.

One solution to this problem is to use standard electronics and encase them in a suitable heat shield so the they will not "see" the high fluid temperature in the wellbore. To overcome the wireline cable problem, the downhole instrumentation can be provided with an electronic digital memory for data storage. Then the tool may be operated on standard braided or slickline cable. However, disadvantages to this technique are that it is not possible to obtain real time data from the well and the memory in the tool may put some limitations upon the type of instrument which may be used.

In this paper, an overview of the geothermal instrumentation program at Sandia National Laboratories will be presented. First, some of the past efforts in high temperature instrumentation will be discussed. (A previous summary of Sandia's geothermal instrumentation efforts may be found in Carson, 1985.) These include the acoustic borehole televiewer (BHTV) and the instruments developed for the Salton Sea Scientific Drilling Program (SSSDP). Next the current work in high temperature instrumentation will be presented. These include some development work on a high temperature BHTV, based upon the previous design, sponsored by the Geothermal Drilling Organization, modifications which have been made to one of the tools developed for the SSSDP, and a new high temperature tool being developed for the Continental Scientific Drilling

Program VC-2B (Baca Flats) drilling project. Finally, a discussion of possible future instrumentation development efforts which may be undertaken will be presented.

ACOUSTIC BOREHOLE TELEVIEWER

The acoustic borehole televiewer (BHTV) is an instrument which has been used for wellbore fracture detection, casing inspections, and for checking the integrity of casing-cement seals. About five years ago, Sandia completed the modifications to a commercially available tool to extend its operational range to 275°C and 5000 psi (Heard and Bauman, 1983). The tool modifications included the development of a rotating head transformer, a high temperature transducer, and a redesign of the electronics for high temperature operation. The tool had been successfully tested in numerous wells (Heard and Bauman, 1983; Bauman, 1985).

GDO-SPONSORED BOREHOLE TELEVIEWER

The Geothermal Drilling Organization funds projects of interest to the geothermal industry jointly with DOE and industry funds (Dunn, 1987). One such project is the high temperature BHTV. This BHTV will use the modifications from the Sandia BHTV project to construct two high temperature televiewers which will be used for logging in geothermal wells. Part of this project included the development of a real time computer display to observe the data as it is received from the tool. A prototype of this system was successfully tested at Mammoth Lakes, California in October 1987.

SSSDP TOOLS

Five tools were developed for use in the SSSDP. These tools and the developmental effort have been described elsewhere (Carson, 1986; Carson and Wolfenbarger, 1986); only a brief summary and a discussion of what was learned from this effort will be provided here. The well drilled for the SSSDP was completed in March of 1986 reaching a maximum depth near 10,600 ft with a bottom-hole temperature of 350°C (Sass, et al, 1986). The short development schedule (6 to 8 months) precluded any extensive new tool development effort. Rather, existing electronics were to be used and repackaged for high temperature use. These tools were required to operate on a slickline cable, operate up to a temperature of 400°C for 10 hours using a protective heat-shield, and be constructed of a suitable corrosion-resistant alloy for operation in the Salton Sea well.

The five tools developed for the SSSDP are summarized in Table 1. The tools were used at three different testing times in the well. For the intermediate flow test, conducted when the well reached a depth of 6000 ft in December 1985, the mechanical temperature and pressure tools were successfully operated. Some problems developed with the battery pack/timer/fluid sampler which required some further work. During the final flow test, conducted when the well reached a final depth of 10,000 ft in March 1986, the mechanical temperature and pressure tools were again operated successfully. The battery pack/timer/fluid sampler successfully returned one sample to the surface. The mechanical flow tool was only partially successful; the impeller on the tool jammed in the hole during its logging run. Finally, some post flow testing was conducted using both the mechanical and digital temperature tools and then using only the digital temperature tool. The hole was logged using the digital tool in April 1986, October 1986, and in July 1987. Four successful logging runs were made with the digital tool prior to July 1987. However, the last logging run, attempted in July 1987, was unsuccessful due to a seal failure on the heat-shield of the digital tool. This permitted high temperature wellbore fluid to enter the internal electronics of the tool causing the failure of these electronic components. The temperature logs obtained from this testing may be found in Sass, et al, 1988.

Table 1

Tools developed for the SSSDP.

- Mechanical logging and recording tools for temperature, pressure, and flow[1]
- Digital temperature/pressure tool[2]
- Battery pack/timer for Los Alamos National Lab. fluid sampler[3]

[1]Built by the Kuster Co. of Long Beach, CA.

[2]Built by Madden Systems Inc. of Odessa, TX.

[3]Built by Sandia.

Some recommendations about high temperature instrumentation resulted from the experience with the tools developed for the SSSDP. The digital temperature/pressure tool was preferred over the mechanical tool. The reasons for this were that the data reduction on the digital tool were simple compared to analyzing the inscribed record from the mechanical tools. In addition, the temperature sensor on the digital tool had a rapid response time compared to the mechanical temperature tool. This allowed the digital tool to measure a complete temperature profile as it was logged down the hole. The mechanical tool, on the other hand, required 20 to 30 minutes to stabilize at a new temperature; only a few selected depths could be measured. For the digital tool, a depth acquisition system using a computer rather than manual recording of the time vs. depth is required; the digital tool also requires a well designed double seal on the heat shield to eliminate a possible failure due to fluid leakage into the tool. Finally, the failure of the mechanical spinner-type flow tool in the test at the SSSDP well strongly suggests that development work is

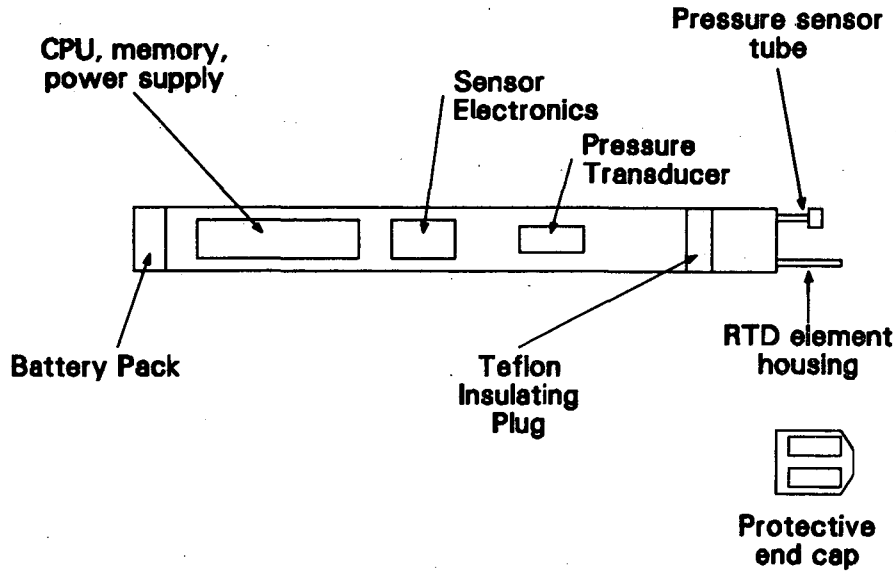


Figure 1

Schematic view of the internal components of the digital temperature/pressure tool.

Table 2

Features of the digital temperature/pressure tool.

- 3.5 inch diameter, 4 ft long, 100 lbs
- Dewar heat shield protection to operate for 10 hours at 400°C
- Programmable time steps
- 1000 T/P data points
- Interfaces with a computer at the surface
- Temperature measurement: Platinum RTD; 0 to 600°C range; accuracy of .5°C
- Pressure measurement: Quartz crystal; 0 to 15,000 psi range; accuracy of 3 psi

necessary on new flow measurement systems which may be used in a geothermal environment.

Since the digital tool developed for the SSSDP is preferred for high temperature logging operations over the mechanical-type tools, a brief discussion of this tool will be provided. Table 2 summarizes some of the essential features of the digital tool. An important point is the use of a dewar heat shield for protecting the electronic components from high temperature. This means that standard rather than specialized high temperature components could be used in the construction of this tool. Figure 1 presents a schematic view of the internal arrangement of this tool. Important design features required for the protection of the electronic components are the separation of the sensor elements from the electronics by an insulating plug made from Teflon and the incorporation of a large separation distance to further buffer the electronics from the external temperature.

DIGITAL TOOL MODIFICATIONS

Several modifications have been made to the digital temperature/pressure tool originally developed for the SSSDP. A secondary seal has been added to the heat shield. A depth encoder system was developed for use with this and similar tools. Finally, a new pressure transducer and some additional electronic circuitry have been incorporated in the digital tool to allow simultaneous measurement of external temperature and temperature-compensated external pressure.

A depth encoder system was developed for use with this tool. As mentioned previously, the digital tool records the temperature and pressure as a function of time. In previous logging operations using this tool, the depth was manually recorded as a function of time at the surface. Then the time/temperature data from the tool and the time/depth information recorded at the surface were manually correlated. A depth encoder system was developed to eliminate the manual recording and correlation of the data. This system uses an optical encoder attached to a measuring wheel and a counter attached to the optical encoder. The

counter is connected to a computer by a serial interface. Before a logging run, the timing on the digital tool and the computer is synchronized. The computer records the depth as a function of time and, after the tool is returned to the surface, the temperature/pressure and the depth are correlated by the computer. Unfortunately, the depth encoder system could not be completely tested using the digital tool due to the seal failure on the digital tool. However, the system was tested with a low-temperature version of the same tool (manufactured by Madden Systems, Inc. of Odessa, Texas). A low temperature well in Oklahoma was logged in March, 1988, to a depth of 17,000 ft (Jacobson and Meyer, 1988). Three separate logging runs were required because of the memory limitations of the tool. The complete system worked well producing a reproducible temperature vs. depth profile.

The pressure transducer originally included in the digital tool required a measurement of the internal temperature near the transducer in order to obtain correct temperature-compensated pressure data. This transducer has been replaced in favor of a model which provides a temperature output. The circuitry of the tool has been modified so that for every ninth pressure reading the temperature output, rather than the pressure, from the transducer is recorded. This modification allows the tool to obtain temperature and pressure measurements of the wellbore fluid.

SMALL DIAMETER HIGH TEMPERATURE TOOL

In July 1988 drilling will begin for the VC-2B well in the Valles Caldera in northern New Mexico. This project is part of the Continental Scientific Drilling Program. Its objective is to obtain complete core to a depth between 6000 and 7000 ft where the bottom-hole temperature is expected to exceed 300°C. A limitation for the temperature logging of this well is the requirement of a small diameter logging tool - not greater than 2 inches. As noted above, the diameter of the digital tool developed for the SSSDP was 3.5 inches. Hence, a new small diameter temperature tool is necessary to meet the logging requirements of this well.

A developmental effort has been undertaken with the Geophysical Research Corp. of Tulsa, Oklahoma to construct a tool suitable for use in this well. The specifications of this tool are summarized in Table 3. This tool, like the digital tool developed for the SSSDP, will be protected by a heat shield to allow the internal electronics to survive when the outside temperature becomes high. The major differences between this tool and the digital tool are: 1) smaller tool diameter for the GRC tool; 2 inches versus 3.5 inches; 2) larger memory capacity for GRC tool; and 3) no pressure measurement capability for the GRC tool. Development and construction of this tool should be completed by September 1988 in time for the logging of the VC-2B well.

Table 3

Specifications of high temperature tool being built by the Geophysical Research Corp. for the logging of the VC-2B well.

- Maximum temperature: 400°C
- External and internal temperatures will be measured
- Tool Diameter: 2 inches
- Electronic memory for 10,000 temperature readings
- Slickline and wireline use
- Rapid response time for the temperature sensor

FUTURE INSTRUMENTATION EFFORTS

Several different instrumentation efforts and concepts will be pursued by Sandia over the next few years. These include the development of instruments survivable to temperatures up to 500°C, a modular memory/controller concept for downhole instrumentation, and the development of other useful high temperature tools.

With the increased need for high temperature instrumentation, the potential exists for the development of many new tools. These tools would most likely require a heat shield for protection of the electronics and an internal memory for data storage. Therefore, it seems appropriate to design the tools in modular form. For example, an internal memory and a controller section would be common to all the tools. The design of a system that could be used for several different tools should reduce the cost of tool development since only the sensor section of each new tool must be designed and built. In addition, with an adapter for the sensor section, this section could also be used with a wireline cable for lower temperature applications. This concept is used in the tool which is being assembled for the VC-2B well. However, the development effort will include the use of more advanced processor chips, a larger internal memory, and more versatility in the controller section so that many different types of instruments could be used.

Finally, there is a need for the development of other high temperature logging tools. These could include tools for flow, gamma ray/CCL, pH, electric logs, density/porosity, and for cement bond logging. Plans are to include new tools in the existing digital self-contained tool inventory.

ACKNOWLEDGEMENTS

The author gratefully acknowledges the useful discussions with R. D. Meyer, R. D. Jacobson, J. E. Uhl, P. C. Lysne, and J. C. Dunn. This work was supported by the U. S. Department of Energy at Sandia National Laboratories under Contract DE-AC04-76DP00789.

REFERENCES

Bauman, T. J., 1985, "A Geothermal Lost Circulation Zone Mapping Tool", Geothermal Resources Council Transactions, Vol. 9-Part II, pp. 431-436.

Carson, C. C., 1985, "Geothermal Instrumentation Development Activities at Sandia", Geothermal Resources Council Transactions, Vol. 9-Part II, pp. 447-450.

Carson, C. C., 1986, "Development of Downhole Instruments for Use in the Salton Sea Scientific Drilling Project", Geothermal Resources Council Transactions, Vol. 10, pp. 449-453.

Carson, C. C. and F. M. Wolfenbarger, 1986, "Development of Slickline Logging Tools for Very High-Temperature Applications", Paper SPE 15606, presented at the 61st Annual Technical Conference of the Society of Petroleum Engineers, New Orleans, LA, October 5-8.

Dunn, J. C., 1987, "The Geothermal Drilling Organization", Geothermal Resources Council Transactions, Vol. 11, p. 33.

Heard, F. E. and T. J. Bauman, 1983, "Development of a Geothermal Acoustic Borehole Televiewer", Sandia National Laboratories Report SAND83-0681.

Sass, J. H. and W. A. Elder, 1986, "Salton Sea Scientific Drilling Project: Scientific Program", Geothermal Resources Council Transactions, Vol. 10, pp. 473-478.

Sass, J. H., S. S. Priest, L. E. Duda, C. C. Carson, J. D. Hendricks, and L. C. Robinson, 1988, "Thermal Regime of the State 2-14 Well, Salton Sea Scientific Drilling Project", J. Geophysical Research, to be published.

PROPOSED DOWNHOLE ULTRASONIC QUADRANT FLOW TOOL: TECHNOLOGY BACKGROUND AND DESIGN CONSIDERATIONS

Lawrence C. Lynnworth

Panametrics, Inc.
221 Crescent Street
Waltham, MA 02254

ABSTRACT

An 82 mm OD downhole geothermal quadrant flow tool has been proposed in which any or all of the following four ultrasonic modes may be selected: transmission, reflection, tag correlation, and noise. The reason for proposing ultrasonics is to obtain the required performance while avoiding the limits on other sensors due to their use of moving parts, flow-restrictive orifices, or sensitive surfaces whose heat transfer properties are likely to degrade quickly in the malevolent high-temperature (250 to 350°C) environment downhole. Ultrasonics has the potential to measure annular flow quadrant by quadrant. Such profile data could uniquely contribute towards understanding the orientation of downhole fissures. The reason for investigating as many as four modes is that each is suited for only part of the flow range or flow or wellbore conditions.

INTRODUCTION

The problem of measuring geothermal flows downhole requires the development of a novel sensor and associated electronics that can survive for at least 10 hours in the downhole environment to ~250°C in many cases and to T_{max} = 350°C in some cases; pressures to 10,000 psi; use only one monoconductor power and data line, or alternatively, operate as or in conjunction with a battery-powered data logger capable of storing on the order of 1000 readings downhole, to be unloaded after the tool is retrieved; preferred tool diameter not more than 82 mm. Furthermore, the tool should be able to measure **total flow**, and also **flow profile** around itself to indicate the **orientation of the fracture.** The tool should not be based on oversimplified assumptions, that is, the tool design should anticipate single- and two-phase flow; low and high velocity flow; aggressive fluid; rough handling. If a tool could be demonstrated to achieve most or all of these characteristics, it could be used to assess geothermal resources more precisely than is possible with existing flow tools. These resources, being better understood, could then be utilized more effectively. Tools similar to that proposed, except of somewhat smaller diameter (43 mm) and a lower limit on T_{max}, would be of value to the oil and gas industry for exploration and well logging.

The **main requirements** for an **ideal downhole flowmeter** may be summarized in general terms as follows. A device is needed that can reliably answer these questions:

- What is flowing at all depths of interest?
- What is the flow velocity V_i of each component? (i = 1, gas = 2, liquid; i = 3, solid)
- What is the circumferential distribution ($V_{i\phi}$) of flow?

One of the simplest special cases occurs when the fluid is single phase (e.g., all liquid); when the flow is vertical and uniform (V_ϕ = const.), and when the flow range V_{max}/V_{min} is small. Even in this "simple" case the measurement of flow velocity V downhole is difficult compared to conventional flow measurements near sea level. Difficulties arise downhole because:

- The downhole flowmeter "tool" OD (outside diameter) generally must not exceed 43 mm for oil and gas exploration, and 82 mm for geothermal instruments;
- Power and data either must all be communicated to and from the tool only via a single-conductor armored cable, or a battery-powered instrument must operate as or in conjunction with a downhole data logger;
- Power and/or data from adjacent tools or devices in the string may need to pass through the flow sensor;
- Measurements may be required while the tool is in motion;
- Ambient temperature, as far as the geothermal tool is concerned, is often around 250°C but in some wells it reaches 350°C;
- The geometry of the hole is not necessarily a circular cylinder concentric with the tool.

Because of the high cost and aggravation associated with replacing a defective tool which fails at a depth of several km, reliable operation is especially important and is required despite exposure to wide ranges of pressure, flowrates and particulates. The cost of lost data may also be significant in dynamic situations.

Problems with Conventional (Nonultrasonic) Flowmeters. Of the many different types of flowmeters, only **turbine** or **impeller** (**"spinner"**) types are now in wide use downhole. Their main drawback is that they are easily fouled by particulates. Errors are then large, especially at low flowrates, $V < 0.3$ m/s. Sudden exposure to a vapor generally overspins turbines and this too causes decalibration or complete failure. Single impellers do not provide profile data, e.g., relative flow per quadrant. **Orifice Plates** or **venturis** cannot handle the wide range of flows encountered, due to their nonlinear (square law) response. **Thermal** devices are limited by variability in heat transfer coefficient as the composition of the fluid changes, and by trade-offs between ruggedness and sensitivity.

TECHNOLOGY BACKGROUND

Flow Velocity V, Volumetric Flowrate Q, and Mass Flowrate M

At present there are at least twelve different ways of obtaining flow velocity data ultrasonically (Fig. 1, from Lynnworth, 1989). Four of these-transmission, reflection, tag cross-correlation, and noise - seem potentially relevant to downhole geothermal flow velocity measurement or fissure characterization. Contrapropagating transmission and reflection (Doppler) methods are probably the best known methods illustrated in Fig. 1. [Vortex shedding ultrasonic flowmeters, not considered now for this application, ought to be recognized, however, as the ultrasonic flowmeter method probably in numerically-greatest industrial use at this time, because of automobile engine air flow applications (R.D. Joy, priv. comm., 1988; Ch. 10 in above reference)].

Contrapropagation Briefly, the contra-propagation method involves timing ultrasonic pulses travelling with and against the flow. The method was first used successfully around 1947. From the measured times, and a few geometric parameters, the flow velocity V can be determined very accurately over the acoustic path. But unless the flow profile is known, how can one determine the average velocity $\bar{V}$ over the cross section of flowing fluid?

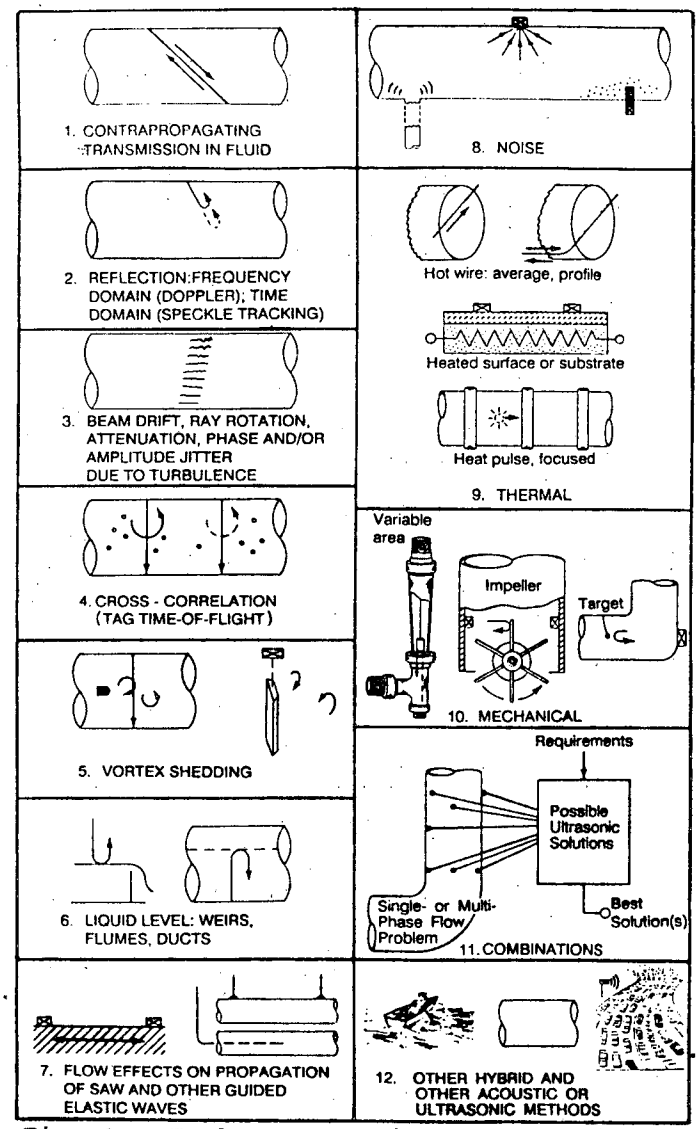


Fig. 1. Twelve categories of acoustic or ultrasonic flow measurement principles and methods, with examples. Flow generally from left to right. © 1989 Academic Press. Used by permission.

In a few special cases $\bar{V}$ can be calculated to an accuracy of about 1% of reading. Such special cases occur in pipes where flow symmetry exists, or where Gaussian quadrature multichord measurements can be obtained, or where the entire pipe cross section can be sampled. In these cases the volumetric flowrate Q can be accurately determined as $Q = \bar{V}A$ where A = cross sectional area of the pipe. If the average density ρ is known, calculable from temperature and pressure, or measurable, then the mass flowrate M is obtainable as $M = \rho Q = \rho \bar{V} A$.

In the proposed quadrant flow tool, determining V in N, S, E and W quadrants is one of the objectives. But if total flow is to be determined, it is often useful to compute $\bar{V}$. A number of commercially-available contrapropagation flowmeters can resolve transit times to $\pm$ 1 ns (1 ns is the time it takes light to

travel 30 cm in air). This means that 1% accuracy is not obtainable unless the upstream-downstream time difference $\Delta t \geq$ 100 ns. Since $\Delta t = 2LV/c^2$ where L = component of interrogation path in the flow direction, and c = sound speed in the fluid, it turns out that to measure V accurately for V > 1 m/s, L need not be very long; 5 cm suffices. But for small V, say V = 10 cm/s, L must be increased to 50 cm to maintain the same (e.g., 1%) accuracy.

Another limitation on the contrapropagation method becomes apparent if the fluid is highly turbulent or multiphase, such that attenuation becomes so high that transmission is blocked.

A third limit occurs downhole if washout eliminates a concentric reflector whose existence is required for a zigzag interrogation in the annulus between tool and wellbore.

Reflection Reflection (Doppler frequency shift) methods have been used in industry since the 1970s to measure V in slurries and other two-phase fluids. In 1985 Embree and O'Brien reported on a new double-pulse reflection method that is analogous to a radar moving target indicator at an airport control tower. In this method the change in range to scatterers (e.g., red corpuscles in blood) is determined by correlating echoes from interrogation pulses spaced at appropriate intervals, say 1, 2, 5 or 10 ms. Since the method involves time differences rather than frequency differences, it was recognized by Jacobson et al. (1987) that the same electronic intervalometer could easily incorporate both this mode and the contrapropagation mode. The double pulse reflection method seems especially useful in tracking scatterers (speckle) at low V where in the contrapropagation mode, assuming L < 30 cm, Δt would be << 100 ns, too low to be measured accurately with electronics having 1 ns resolution.

Tag Cross Correlation In this method, eddies or other natural or induced tags are timed as they pass between two beams or two segments of a beam. The method appears applicable to many fluids where reflection might work too. But the tag mode yields V independent of sound speed c. This is in contrast to reflection methods, which fundamentally yield the Mach number V/c. The tag mode has some other advantages, one of which is that common mode noise can be reduced by quadrature detection (Jacobson et al., 1985).

Noise. Noise measurement can provide some information about flow but is generally the least accurate of the ultrasonic ways to measure flow. Among its potential advantages one can list: passive; can be direction-sensitive; spectrum analysis may indicate fissure size; possibly useful in leak detection and leak location, areas where it has been frequently successful in pipelines and above-ground applications.

A brief summary of the foregoing four modes appears in Table 1. The possibility of one downhole instrument automatically selecting the most appropriate mode or modes in response to dynamically changing conditions is indicated in Fig. 2.

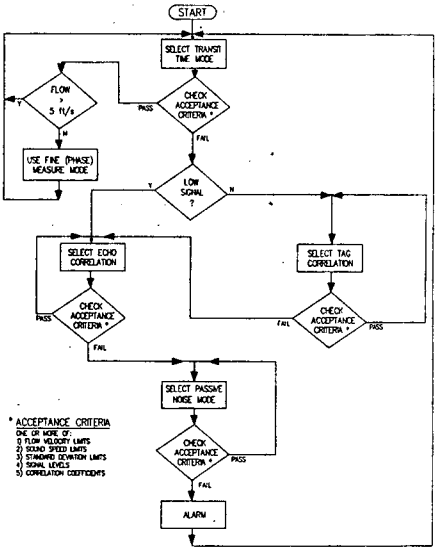


Fig. 2. Flow chart shows how a "smart" flowmeter selects the best measuring mode from its four-choice main menu. The four choices correspond to modes identified in Table 1 as: Transmission, Reflection, Tag Cross-Correlation, and Noise.

Torsional Wave Density Sensor In 1977 the author found that if a waveguide had a noncircular cross section, the speed of torsional waves depended almost linearly on the density ρ of the surrounding fluid, Fig. 3. A theory appeared afterwards (Bau, 1986), subsequently refined (Kim and Bau, 1988) so that the sensitivity now achievable by using an optimized cross section is over three times better than for the rectangular cross section of 1977 having the same aspect ratio b/d ≈3.

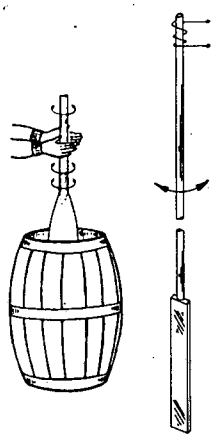


Fig. 3. Inertia of fluid surrounding a waveguide of noncircular cross section reduces the speed of torsional waves. Fluid density can be determined by measuring the time between echoes generated at two points along the noncircular waveguide, typically the waveguide's beginning and end.

Table. 1. Comparison of four of the ways that flow has been measured by ultrasound.

	TRANSMISSION	REFLECTION
ADV.	Accurate to 1% in many cases. Yields both V and c. Response time has been as fast as 1 ms in instruments where t and Δt were the only outputs.	Appropriate for 2-ø and 3-ø media. Can be range gated to measure profile. Can use small paths and can measure even low-V magnitude and direction in double-pulse mode. Can define its own path, i.e., does not require cylindrical wellbore.
DISADV.	Requires sonic conduction and path long enough for Δt to be "large", e.g., 100 ns. Requires defined path.	Requires scatterers. Measures V/c, not V, in general. Does V/c represent flow of scatterer or medium? Profile- and α-dependent Doppler accuracy typ. 2-5%, seldom 1%.
	TAG CROSS-CORRELATION	NOISE
ADV.	Adv. same as refl., plus: V independent of of c; can do 1-ø if highly turbulent.	Passive. Qualitative, leak Y/N. Locate source of leak. Spectrum analysis and cross correlation possible.
DISADV.	Can't do 1-ø laminar flow. Accuracy typ. 2%, seldom 1%. Historically expensive. No general solutions.	Examples of quantitative flowrate measurements scarce and historically expensive. Used in special cases only, e.g., pipeline leak detection.

By resolving transit times of 100 kHz torsional pulses to $\pm$ 10 ns, ρ can be resolved to $\pm$ 1 mg/cm^3 using stainless steel sensors 20 cm long (straight or spiraled). Again, the "flowmeter" intervalometer can be programmed to accommodate this additional "mode". Several torsional densitometer sensors have been or soon will be under test in high-temperature fluids ranging in one case up to 500°C. Whether such ρ sensors will be useful in measuring steam quality, mass flowrate or other ρ-related measurands downhole or in above-ground piping remains to be seen. Its use in two high-temperature water or water/steam projects is reported in Arave et al. (1978) and Miller et al. (1980).

Transducers for High Temperature A number of electroacoustic materials exist with Curie point or transformation temperature above 350°C (Table 2). Propagation of ultrasound in solids, liquids or gases at high temperature, well over 1000°C, is certainly possible. Why, then, can one not simply buy high temperature transducers and build a high-temperature flowmeter?

Table 2. High-temperature limits on some ultrasonic transducer materials.

Piezoelectrics	Curie Point, °C
a. PZT-5A	365
b. $PbNb_2O_6$	570
c. $LiNbO_3$	1210
Magnetostrictives	
a. Nickel	358
b. Fe-Co-Mn-Va	920

One reason is that the piezo or magnetostrictive materials need to be housed to protect their electrodes, coils or leadwires from corrosion, impact and shorting. To house a transducer for downhole use ordinarily requires one to dampen and bond an electroacoustic element to corrosion-resistant metal having a different expansion coefficient. Perhaps Ti will provide a suitable housing. It is corrosion-resistant and of relatively low acoustic impedance for a metal (about half that of stainless steel). It has been in use since 1982 in ultrasonic flare gas flowmeters (Smalling et al., 1984) in malevolent environments, but not over 150°C. Another possibility is to house a magnetostrictive transducer alloy within a PM35 housing (material suggested by Sally Benson, priv. comm., June 1988), with bonds brazed to withstand 350°C service.

Electronics for High Temperature In Phase I of this proposed study, no attempt will be made to repackage existing electronics hardware. It is known that Mil Spec CMOS circuitry can be built for 125°C service. Using a dewar, heat shielding, thermal masses and a phase change material, and perhaps heat pumping and heat sinking, slickline (Duda, 1988) or monoconductor-powered instruments have been built. If the proposed downhole ultrasonic flowmeter advances to Phase II, presumably these thermal protection techniques will be applicable, enabling the flowmeter electronics to function long enough at the maximum temperatures of interest.

Downhole Designs

Two approaches will be reviewed here: internal and external. In the **internal**

approach, flow is collected and funneled by a diverter basket through the flow tool. In the **external** approach, the flow tool is centralized in the wellbore and the **annular flow** outside the tool is measured. (This latter approach is recognized as the inside-out dual of conventional ultrasonic zigzag flowcells.) In the author's laboratory both internal and external approaches were investigated at room temperature using experimental tools similar to those shown in Fig. 4 and 5. Data uncorrected for profile or end effects are plotted in Fig. 6. In this figure, the internal approach used an axial path ~356 mm long, while the external approach measured flow in the annulus between a 42 mm OD tool and a nearly-concentric pipe having an ID = 154 mm.

For further background on pre-1988 downhole flow instrumentation, see Carson and Wolfenbarger (1986) and DiBello et al. (1987).

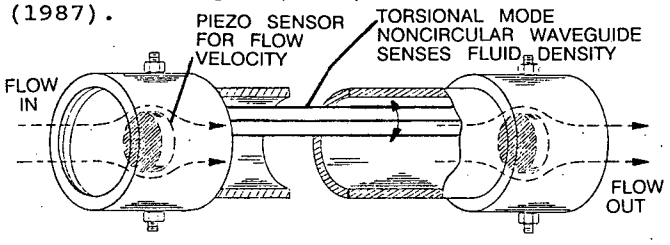


Fig. 4. Laboratory model of a restricted-OD flowmeter, where flow is measured **inside** the "flow tool", similar to design in Lynnworth et al. (1986).

In mid-1988, work is expected to begin on the design, construction and testing of transducers to meet the high-temperature, high-pressure requirements of this downhole geothermal application, in a DOE-sponsored Small Business Innovation Research program.

QUADRANT FLOW TOOL CONCEPT

Ultrasonic paths in Fig. 5 that turn out to be effective can be utilized in different sectors around the flow tool. One arrangement would consist of transducer patterns replicated in each quadrant so that flow could be measured in each of four 90° sectors. If the tool's geographic orientation were known or controllable, then flow readings in these quadrants could be resolved into N, S, E and W components. Apart from geothermal wells, if one considers a deviated (non-vertical) oil-producing well, it may be sufficient in some cases to resolve flow to "top" and "bottom" locations, e.g., where oil may tend to flow in an upper channel, and water in a lower channel.

Since ultrasound generally can distinguish flow direction as well as magnitude it would appear that, if accurate flow measurements can be obtained as a function of orientation around the flow tool, a better understanding of downhole flow dynamics will be obtained.

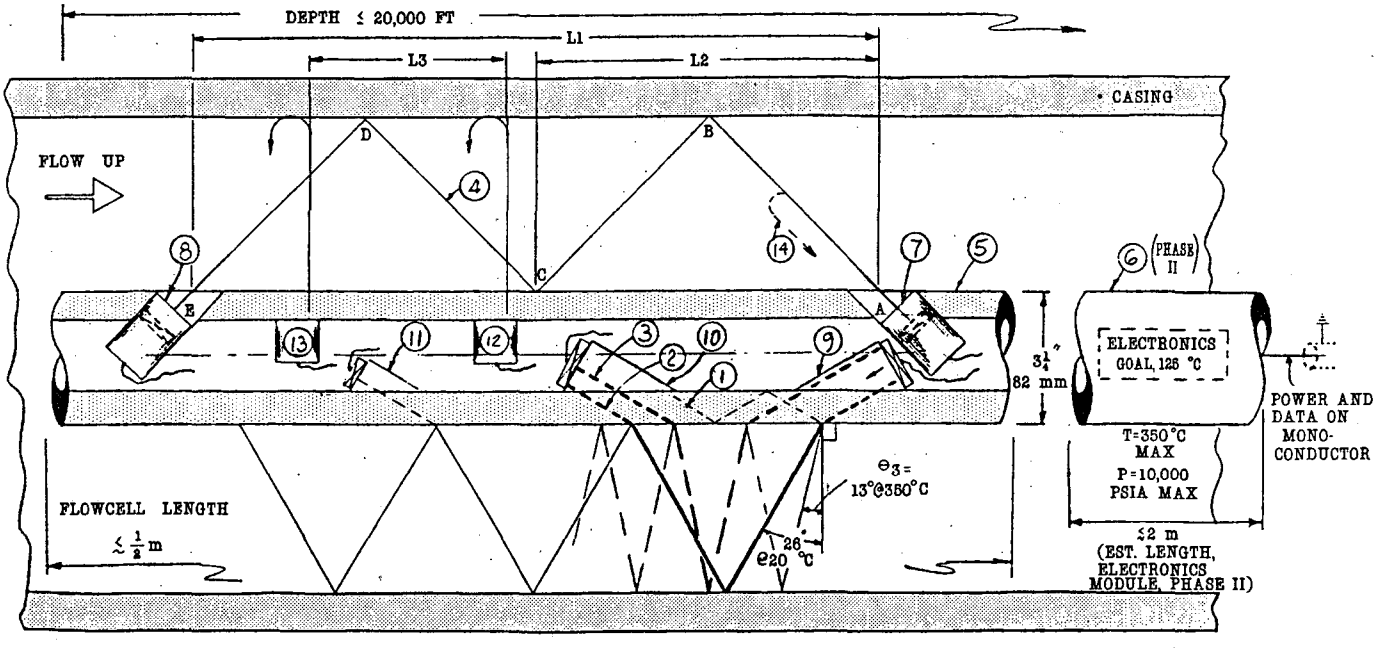


Fig. 5. Proposed downhole flowmeter concept for measuring flow **outside** the tool, in the annulus between the tool and the wellbore or wellbore casing. Legend: 1-Acoustic short circuit; 2-Fluid-borne signal at 20°C; 3-Fluid-borne signal at 350°C; 4-Zigzag path in annulus; 5-Flow sensor module; 6-Electronics module; 7,8-Wetted transducers; 9, 10, 11-Nonwetted oblique transducers; 12,13-Nonwetted normal transducers for tag, radial reflection or noise modes; 14-Echo to be analyzed in reflection mode [range-gated transit time (speckle tracking) mode].

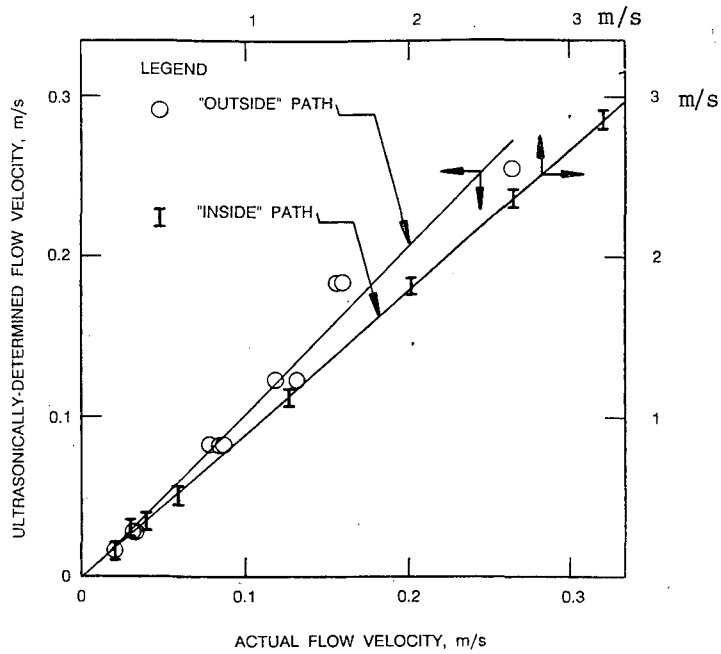


Fig. 6. Laboratory data obtained with water at room temperature with **internal** and **external** ultrasonic flow tool experimental designs. The **internal** flow tool, similar to that in Fig. 4, was tested in a flow loop where all the water flow was confined to an axial path inside a 1.25-inch schedule 40 SS pipe section. Passageways represented by the dashed lines in Fig. 4 conveyed the water around the piezoelectric transducers at each end of the axial path. The **external** flow tool was tested inside a 6-inch schedule 40 Ni-plated steel pipe using a zigzag path essentially like path 4 between transducers 7 and 8 in Fig. 5.

REFERENCES

A.E. Arave, E. Fickas and W. Shurtliff, Instrumentation in the Aerospace Industry - Vol. **24**, Proc. 24th International Instrumentation Symposium, pp. 609-620, ISA (1978).

H.H. Bau, Torsional Wave Sensor - A Theory, ASME J. Appl. Mech. **53** (4), pp. 846-848 (Dec. 1986).

C.C. Carson and F.M. Wolfenbarger, Development of Slickline Logging Tools for Very High-Temperature Applications: Soc. Petr. Engrs. Paper SPE-15606, presented at the 61st Annual Technical Conference and Exhibition of the SPE at New Orleans, LA (October 5-8, 1986).

E.G. DiBello, J.L. McWilliams, K.R. Haack, G.E. Pax and S.S. Waterbury, Downhole Flowmeter Final Report, BDM (October 1987).

L. Duda, High-Temperature Instrumentation, Advances in Geothermal Reservoir Technology - Research in Progress, Conf. Proc. (June 14-15, 1988).

S.A. Jacobson, P.N. Denbeigh and D.E.H. Naude, A New Method for the Modulation of Ultrasonic Signals for Cross-Correlation Flowmeters, Ultrasonics **23** (3), pp. 128-13 (May 1985).

S.A. Jacobson, L.C. Lynnworth and J.M. Korba, Differential Correlation Analyzer, U.S. patent application serial no. 103,066 (Sept. 30, 1987).

J.O. Kim and H.H. Bau, On Line Real Time Densimeter - Theory and Optimization, to be presented at ASME Winter Annual Meeting (1988).

L.C. Lynnworth, Slow Torsional Wave Sensors, pp. 29-34 in: Proc. 1977 Ultrasonics Symp., IEEE (1977).

L.C. Lynnworth, Ultrasonic Measurements for Process Control, Academic Press (1989).

G.N. Miller, R.L. Anderson, S.C. Rogers, L.C. Lynnworth, W.B. Studley and W.R. Wade, pp. 877-881 in: Proc. 1980 Ultrasonics Symposium, IEEE (1980).

J.W. Smalling, L.D. Braswell, L.C. Lynnworth and D.R. Wallace, Flare Gas Ultrasonic Flowmeter, Proc. 39th Texas A&M Symp., pp.27-38 (1984).

ACKNOWLEDGEMENTS

The author gratefully acknowledges the encouragement and cooperation of Marshall Reed of DOE, Marcelo Lippmann of Lawrence Berkeley Laboratory, and Ron Schroeder of BGI.

Geothermal Reinjection Research and Instrumentation Development at LBL

Sally M. Benson

Earth Sciences Division
Lawrence Berkeley Laboratory
University of California
Berkeley, California 94720

Abstract

This paper describes current research activities in geothermal reinjection and borehole instrument development at Lawrence Berkeley Laboratory. During the past year reinjection research has been directed towards understanding the pressure transient response due to cold water injection in a geothermal reservoir. Analyses of several data sets indicate that the permeability of the near-bore region increases in response to cold water injection, probably due to thermal contraction of the rock and subsequent stress cracking. Two efforts are underway in instrumentation development. A downhole fluid sampler, which can operate at temperatures of up to 350 °C and pressures of 10,000 psi has been developed. During the first test of this sampler, a fluid and gas sample was successfully obtained from a producing well at East Mesa, California. A survey of commercially available high temperature pressure transducers is also being carried out to establish the state-of-the-art for these measurements.

Introduction

Reinjection of spent geothermal brine continues to be one of the major issues facing geothermal developers. Injection well performance, thermal breakthrough, and pressure maintenance all require consideration in the design and operation of a reinjection program. Throughout this program, pressure transient testing provides a valuable means of monitoring and assessing the performance of injection wells. Pressure transient injection tests are complicated by large thermal transients in the wellbore and near-bore formation. These thermal transients preclude application of conventional oil-field or hydrological techniques for interpreting the test data. Furthermore, temperature changes may alter the physical and chemical characteristics of the formation to a degree that these changes may be apparent even in the short period over which the test is conducted. A mathematical framework for analyzing non-isothermal pressure transient data in fractured and porous formations has been developed and a computer program has been written to aid in the analysis of such data.

Reliable and accurate measurement of downhole pressure, temperature, and chemical composition of formation fluids continues to be a challenge. In response to this need and to aid DOE-sponsored research, LBL has an ongoing instrumentation development program. We are also conducting a survey of pressure transducer manufacturers and downhole pressure instrument manufactures to assess the state-of-the-art in downhole pressure measurement systems. The hostile conditions, large temperature changes, and high pressures found in geothermal boreholes create an environment in which it is extremely difficult to obtain the high-resolution, real-time downhole pressure measurements that are required for accurate pressure transient analysis.

Permeability Enhancement During Cold Water Injection

Injecting cold water is a common technique for estimating the permeability, productivity, and injectivity of geothermal wells. In addition to providing a measure of these parameters, there is some evidence that this practice stimulates the well (Bodvarsson et al., 1984). This is contrary to the predictions of physical and mathematical models that consider only the temperature-dependent fluid properties (Benson, 1984; Benson and Bodvarsson, 1986).

This intriguing phenomena is particularly apparent in geothermal wells in the Los

Azufres, Mexico, geothermal field where a large set of pressure transient data exhibit unusual characteristics. As shown by pressure buildup curves for four wells in Figure 1, it is not uncommon to observe that after an initial period during which the pressure increases as expected, the pressure stabilizes and then begins to drop, even though injection continues at a steady rate. This unusual behavior is attributed to progressive increases in the near-bore permeability. Several physical mechanisms can increase the near-bore permeability, including; hydraulic fracturing, pushing drilling mud and formation fines away from the wellbore and into the formation, thermal contraction and thermal stress cracking of the rock, and dissolution of fracture-filling minerals. As these tests were conducted well below the fracture gradient, hydraulic fracturing has been eliminated as a possible cause for the permeability increase, leaving one or more of the other mechanisms to account for the observed behavior. The goal of this investigation is two-fold. First we attempt to quantify the magnitude of the permeability increase needed to explain the observed pressure behavior. Next, we investigate correlations between temperature and the permeability increase in an effort to provide insight into the physical mechanism governing this occurrence.

To circumvent the restrictive assumptions required for applying conventional analytical methods to this problem we have developed an approximate solution for calculating the pressure buildup during injection. The solution is in the form

$$\Delta p(r_w,t) = \Delta p_{ss}(r_w,t)+\Delta p_t(r_f,t)$$

where $\Delta p(r_w,t)$ is the pressure change at the injection well, $\Delta p_{ss}(r_w,t)$ is the steady-state pressure change across the invaded region at time t, and $\Delta p_t(r_f,t)$ is the transient pressure response in the uninvaded formation. The mathematical advantages of this form of the solution are two-fold. First, all of the non-linear terms associated with the region behind the front are incorporated into the first term of the right side of the above equation, which for a slightly-compressible single component fluid flowing through a radially symmetric system is given by

$$\Delta p_{ss}(t) = \frac{q}{2\pi h} \int_{r_w}^{r_f(t)} \frac{\mu(r,t)}{k(r,t)\,\rho(r,t)} \frac{dr}{r}$$

where q is the mass injection rate and the other terms are defined as before. Second, the term $\Delta p_t(r_f,t)$ can easily be evaluated from well established solutions such as the exponential integral solution, convolution of the instantaneous line source solution for variable flow rates, or any one of a number of relevant solutions that satisfy the desired outer boundary conditions.

The Los Azufres geothermal system occurs in fractured volcanic rocks, at a depth of 1000 to 2000 m. Reservoir temperatures range from 220 to 280°C in the wells from which injection test data are available. Geothermal fluids are produced from fractured horizons within andesitic rocks. The injection tests consisted of injecting 20°C water for 2 to 3 hours at a constant wellhead injection rate. During injection, the formation pressure was measured with an Amerada pressure gauge positioned in the well adjacent to the production zone.

Log(pressure) vs. log(time) graphs (not shown here) of the pressure buildup data shown in Figure 1 indicate that wellbore storage effects persist throughout the entire 2 to 3 hour test. Another factor that must be considered is that although the temperature of the injected water is constant at the wellhead, it is not constant at the formation face. The sandface temperature decreases throughout the test but by the end of the test, the temperature is still nearly 70°C above the surface temperature. The time-varying injection temperature causes the fluid viscosity and density to vary throughout the test. This creates a non-uniform distribution of the fluid properties in the region behind the thermal front. The computer program INJECT has been developed to interpret test data subject to all of the complexities.

The magnitude of the near-bore permeability enhancement in four wells from Los Azufres (A-7, A-8, A-18 (two tests), and A-53) is plotted as a function of the sandface injection temperature in Figure 2. The calculated permeability increases for wells A-7, A-8, and the first test of A-18 are remarkably similar, suggesting that the correlation between the sandface injection temperature and the permeability increase is attributable to the thermal characteristics of the rock mass. On the other hand, the larger increase in the permeability calculated from the second test in well A-18 suggests that the effects of heating and cooling are cumula-

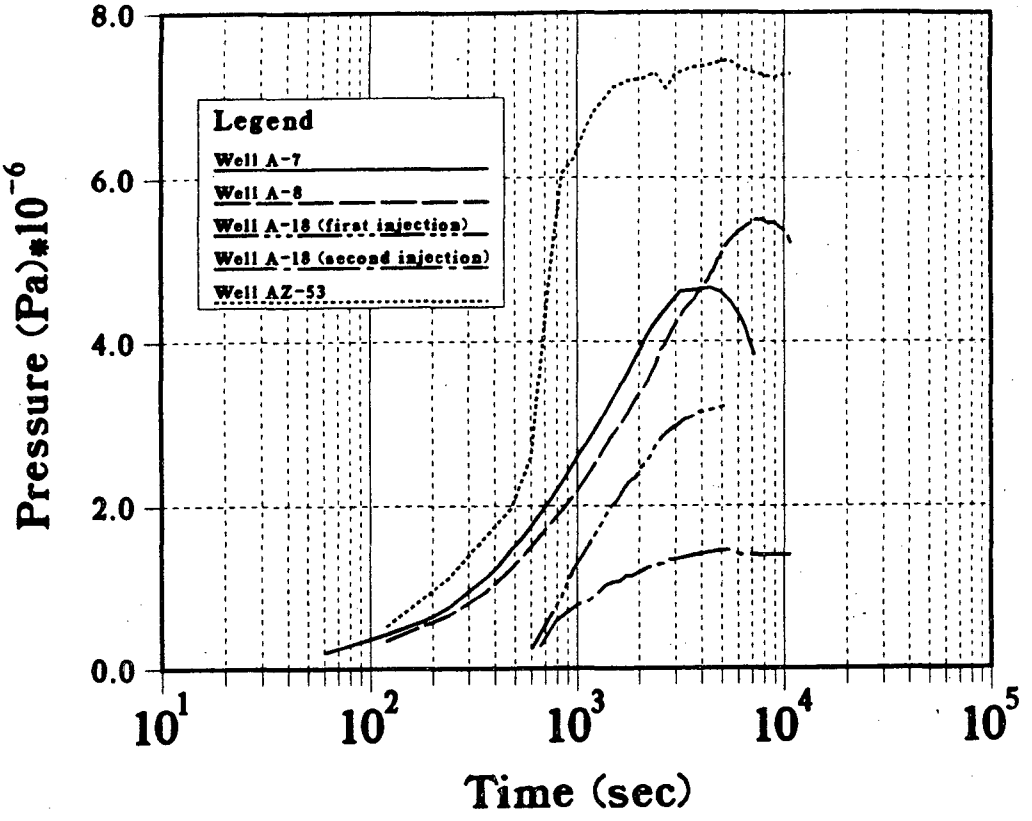


Figure 1. Pressure buildup curves for four wells from the Los Azufres, Mexico, geothermal field during cold water injection.

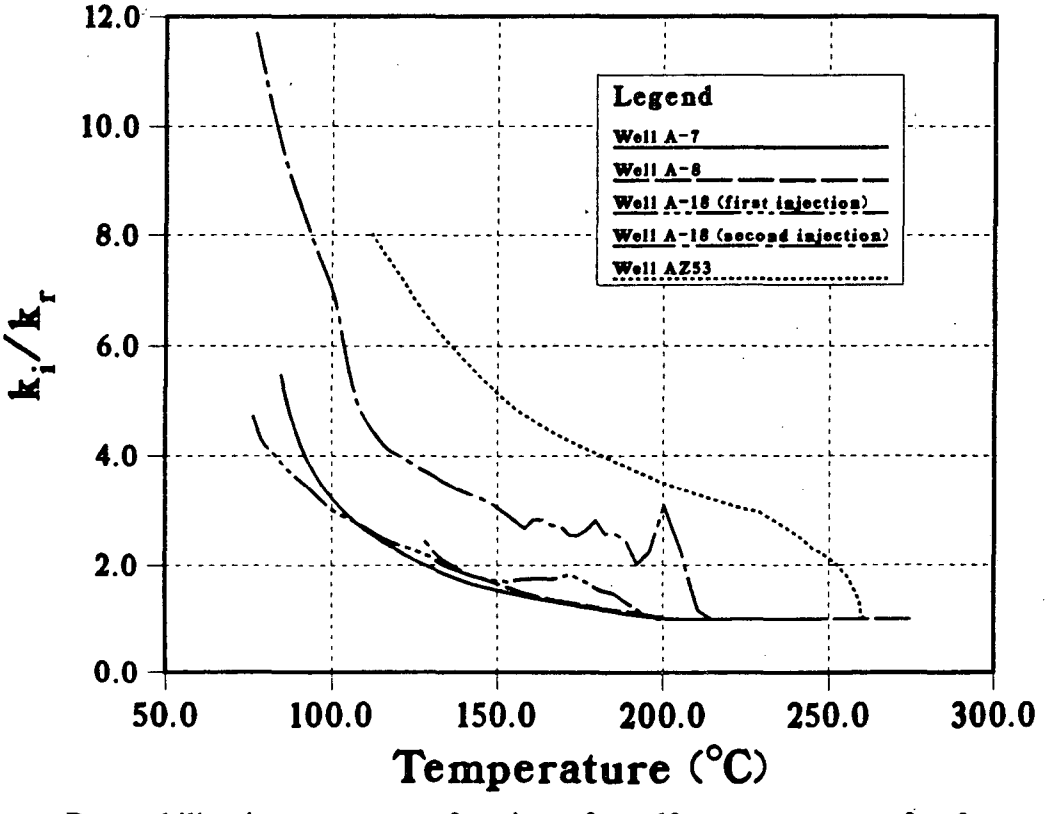


Figure 2. Permeability increases as a function of sandface temperature for four geothermal wells from the Los Azufres geothermal field.

tive. This implies that stress changes occurring during injection also influence the permeability increase. The readjustments of the contact points between the opposing walls of the fractures that take place in response to pore pressure increases and thermal contraction of the rock may result in permanent increases in the near-bore permeability due to the injection of cold water into a geothermal formation.

There are several possible explanations for the observed temperature versus permeability relationship, including; thermal stress cracking, dissolution of the formation minerals, and thermal contraction of the rock matrix. In the absence of additional information, we can not decide which amongst these possibilities is the correct one, nor if a single mechanism is responsible for the observed behavior. Recent laboratory studies of thermal stress cracking indicate that both intragranular and grain-boundary stress cracks can develop in the thermal regime in which these tests are conducted (Fredrich and Wong, 1986). Analysis of field experiments at the hot-dry-rock site at Fenton Hill, New Mexico, indicate that "reservoir growth" can be at least partially attributed to thermally induced stress cracks (Tester et al., 1986). It is likely that a similar mechanism is responsible for the permeability enhancement reflected in the data described here.

The analysis presented is just the beginning of a series of studies that must be conducted if we are to improve our understanding of the physical phenomena that accompany cold water reinjection into geothermal reservoirs. To date, we do not have an adequate understanding of the physical mechanisms causing the unusual pressure transients responses nor the observation that well injectivity is often better than anticipated. The possibility that the observed permeability increases may be permanent or semi-permanent is also intriguing. The extent to which this phenomena may contribute to increased well productivity is being investigated systematically under the DOE/CFE (Comision Federal de Electricidad) agreement. Cold water will be injected into two low-productivity wells at Los Azufres. Periodic pressure falloff and production tests will be carried out to evaluate injection-induced productivity enhancement. Other potential but untested applications of the non-isothermal injection program include thermal front tracking, detection of injection-induced formation plugging, and fracture detection.

LBL Downhole Fluid Sampler

A modified version of the LBL high-temperature sampler has been designed and tested. The new sampler, has a two-liter capacity, is rated for use to 350 °C and pressures of up to 10,000 psi. The design of the sampler is similar to the earlier version, however, the number of parts has been decreased by half (Solbau et al., 1986). This greatly simplifies operation and maintenance of the sampler. It can be run on a slickline with a dewared battery-pack or on a high-temperature logging cable.

A field trial of the sampler was successfully completed in cooperation with GEO Operator Corporation at the East Mesa geothermal field in southern California. A sample of gas and brine was collected at a depth of about 7000 feet. Additional testing needs to be carried out in higher temperature reservoirs to confirm the design specifications.

Pressure Transducers for High-Temperature Borehole Testing

Borehole pressure measurements provide some of the most valuable data for determining the productivity of a geothermal well and for assessing formation characteristics. However, measurements in boreholes with temperatures greater than 150 °C are hindered by the lack of borehole instruments with adequate pressure resolution, accuracy, and reliability. The lack of instrumentation can be attributed directly to a shortage of of electronic pressure transducers that operate adequately at temperatures in the range of 150 to 300 °C (Lamers, 1979). Although there are a handful of manufacturers that sell "high-temperature" pressure transducers and some prototype downhole pressure instruments, the currently available transducers are not well suited for application in geothermal borehole environments because the calibration coefficients of the transducers are temperature sensitive and they tend to drift with thermal cycling, prolonged exposure to high-temperature environments and age. Reliability of these transducers is also of major concern. A high failure rate was observed during a set of bench tests on a number of the currently available

high-temperature pressure transducers (unpublished report to Sandia National Laboratory by Berkeley Group Inc., 1982).

There is a need for thermally-stable pressure transducers that operate in the 150 to 300 °C range. Desirable attributes of these transducers include but are not limited to:

1) minimal time-drift;
2) calibration coefficients with small (<0.001% °C) and stable thermal sensitivities;
3) pressure resolution of at least 0.1 psia throughout the operating pressure range;
4) accuracy of 0.25% full scale;
5) pressure ratings up to 5000 psia; and
6) diameters of about 4 cm or less.

Development of reliable pressure transducers for geothermal borehole environments will provide a much needed tool for assisting geothermal developers in obtaining useful well-field data.

LBL is conducting a survey of pressure transducer manufacturers and wellfield service companies to identify the state-of-the-art in high-temperature pressure measurements. The survey of over 20 instrument manufacturers has revealed that little progress has been made in the past 10 years, with most transducers being essentially unchanged from earlier designs. A report summarizing the results of this survey is being prepared that will include recommendations on directions for future research.

Until higher resolution, more accurate pressure transient data becomes routinely available from geothermal fields, application of state-of-the-art pressure transient analysis techniques is practically impossible. For instance, many of the new pressure transient analysis techniques that are applied widely by the petroleum industry are based on evaluating the shape of the pressure derivative curve, rather than on the pressure data itself. Unless high-resolution pressure data are available for geothermal wells the pressure derivative curve can not be adequately represented, and these methods of analysis can not be used. To keep the geothermal industry abreast of the current trends in formation evaluation, better quality data are required.

Acknowledgements

This work was supported through the U.S. Department of Energy Contract No. DE-AC03-76SF00098 by the Assistant Secretary for Conservation and Renewable Energy, Office of Renewable Technology, Division of Geothermal Technology.

References

Benson, S.M., 1984, Analysis of Injection Tests in Liquid Dominated Geothermal Reservoirs. M.S. Thesis, University of California, Berkeley, California, Lawrence Berkeley Laboratory report LBL-17953.

Benson, S.M. and Bodvarsson, G.S., 1986, Non-isothermal Effects During Injection and Falloff Tests, *SPE Formation Evaluation*, Vol. 1, No. 1, pp. 53-63.

Bodvarsson, G.S., Benson, S.M., Sigurdsson, O., Stefansson, V. and Eliasson, E.T., 1984, The Krafla Geothermal Field, Iceland: 1. Analysis of Well Test Data, *Water Resour. Res.*, Vol. 20, No. 11, pp. 1515-1530.

Fredrich, J.T. and Wong, T., 1986, Micromechanics of Thermally Induced Cracking in Three Crustal Rock, *Jour. Geophys. Res.*, Vol. 91, No. B12, pp. 12743-12764.

Lamers, M.D., 1979, Measurement Requirements and Methods for Geothermal Reservoir System Parameters (An Appraisal), Lawrence Berkeley Laboratory report LBL-9090.

Solbau, R. D., Weres, O., Hanson, L. and Dudak, B., 1986, Description of a High Temperature Downhole Fluid Sampler, *Geothermal Resour. Council Trans.*, Vol. 10, pp. 479-483.

Tester, J.M., Murphy, H.D., Potter, R.M., and Robinson, B.A., 1986. Fractured Geothermal Reservoir Growth Induced by Heat Extraction, paper SPE-15124 presented at the 56th California Regional Meeting of the Society of Petroleum Engineers.

PRESSURE TRANSIENT MODELING OF NONUNIFORMLY FRACTURED RESERVOIRS

Younes Jalali-Yazdi
Stanford University

Ashok Belani
Stanford University

ABSTRACT

Double porosity formulations of naturally fractured reservoirs assume fracturing is uniform and matrix block size is constant. A model is formulated that eliminates this assumption. A distribution of matrix block size is incorporated in a source integral to represent interporosity flow in a nonuniformly fractured reservoir. Uniform fracturing is a special case where the block size distribution is a shifted Dirac delta function. Block size variability affects the pressure response markedly.

INTRODUCTION

It is desireable to estimate the matrix block size distribution from well test data. The mean of the distribution is a measure of fracture intensity. The variance is a measure of the degree of uniformity of fracturing. Such information is necessary in many reservoir engineering calculations such as: (a) estimating recoverable heat from geothermal reservoirs, (b) estimating the rate of imbibition, (c) history matching reservoir performance, and (d) planning development well locations.

A model is formulated that predicts the wellbore pressure response for a fractured reservoir of varying matrix block size. This model can be used to estimate matrix block size distribution from well test data.

THEORY

Fluid flow in a fractured reservoir with a random distribution of matrix blocks of varying size is described by:

$$\frac{k_f}{\mu}\nabla^2 P_f = \phi_f c_f \frac{\partial P_f}{\partial t} + \int_{h_{min}}^{h_{max}} Q(h) f(h) dh. \tag{1}$$

The source integral in Eqn. (1) represents matrix to fracture interporosity flow. Q(h) is the flow contribution from a matrix of block size h, given by:

$$Q(h) = \phi_m c_m \frac{\partial p_m}{\partial t}(h), \tag{2}$$

for pseudo-steady state, and

$$Q(h) = -\frac{k_m}{\mu h}|\nabla p_m|, \tag{3}$$

for unsteady state interporosity flow. f(h) is the matrix block size distribution; it gives the probability of occurrence of a matrix block of size h. For a uniformly fractured reservoir, matrix block size is constant (size H) and hence:

$$f(h) = \delta(h - H) \quad \begin{aligned} &= 0, h \neq H, \\ &= \infty, h = H. \end{aligned} \tag{4}$$

Eqns. (1) and (4) yield the double porosity formulation of a *uniformly* fractured reservoir.

For a nonuniformly fractured reservoir block size varies. An intensely fractured reservoir exhibits a positively skewed matrix block size distribution, i.e., "favors" small blocks. A sparsely fractured reservoir exhibits a negatively skewed matrix

block size distribution, i.e., "favors" large blocks. Fracturing on two scales would exhibit a bimodal block size distribution, i.e., two controlling sets of matrix blocks exist.

A block size distribution of interest is the rectangular (or uniform) distribution where all block sizes (h_{min} to h_{max}) are equally probable:

$$f(h) = \frac{1}{h_{max} - h_{min}}, \tag{5}$$

with mean:

$$h_{mean} = \frac{h_{min} + h_{max}}{2}, \tag{6}$$

and variance:

$$\sigma^2 = \frac{1}{12}(h_{max} - h_{min})^2. \tag{7}$$

The application of the rectangular distribution is two-fold:

1. It should be used when the matrix block size distribution is unknown.
2. A sequence of rectangular distributions can be used to approximate any matrix block size distribution.

SOLUTION

For the radial flow of a slightly compressible fluid in a fractured reservoir of infinite extent where the pressure in the fracture network and the matrix blocks are initially at equilibrium and subsequently flow is linear in the matrix blocks and the mode of interporosity flow is pseudo-steady state, we obtain the dimensionless wellbore pressure response in Laplace space for a rectangular matrix block size distribution:[1]

$$\bar{P}_{DW} = \frac{1}{s} K_0(\sqrt{sg(s)}), \tag{8}$$

where,

$$g(s) = \omega_f + \omega_m \frac{\sqrt{3\lambda_{min}/\omega_m s}}{1-\sqrt{\lambda_{min}/\lambda_{max}}} \times$$
$$(tan^{-1}\sqrt{3\lambda_{max}/\omega_m s} - tan^{-1}\sqrt{3\lambda_{min}/\omega_m s}). \tag{9}$$

[1]See Reference 2 for details.

Parameter s is the Laplace variable related to dimensionless time:

$$T_D = \frac{k_f t}{(\phi_f c_f + \phi_m c_m)\mu r_w^2}. \tag{10}$$

Parameters ω_f and ω_m are the dimensionless fracture and matrix storativity:

$$\omega_f = \frac{\phi_f c_f}{\phi_f c_f + \phi_m c_m}, \tag{11}$$

$$\omega_m = \frac{\phi_m c_m}{\phi_f c_f + \phi_m c_m}, \tag{12}$$

$$\omega_f + \omega_m = 1. \tag{13}$$

Unlike the single block size formulation, Eqn. (9) includes two interporosity flow coefficients λ_{max} and λ_{min} which arise because matrix block size varies uniformly from h_{min} to h_{max}:

$$\lambda_{min} = \frac{k_m r_w^2}{k_f h_{max}^2}, \tag{14}$$

$$\lambda_{max} = \frac{k_m r_w^2}{k_f h_{min}^2}. \tag{15}$$

In general, the interporosity flow coefficient is a variable, $\lambda(h)$, specified by the matrix block size distribution.

In the limit where λ_{min} approaches λ_{max} (or vice versa), Eqn. (9) behaves similar to the single block size formulation of Warren and Root (Reference 1):

$$g(s) = \omega_f + \omega_m \frac{3\lambda}{3\lambda + \omega_m s}. \tag{16}$$

That is, as the rectangular distribution narrows and approaches a Dirac delta function, Eqn. (9) reverts to the conventional uniformly fractured reservoir models. This is indicated in Figure 1. The derivative curve at the far right is the single block size response with $\lambda = 10^{-9}$. Other derivative curves represent the uniform matrix block size distribution response with $\lambda_{min} = 10^{-9}$ and λ_{max} of 10^{-4}, 10^{-5}, 10^{-6}, 10^{-7}, and 10^{-8}. As the spread in matrix block size (or λ)

increases, the pressure response becomes more smooth and the characteristic pressure behavior of a fractured reservoir becomes less pronounced. In such conditions, it is difficult to detect two parallel semi-log straight lines on a drawdown or a buildup plot.

CONCLUSIONS

1. A robust formulation of pressure transient response in a nonuniformly fractured reservoir is developed.

2. The characteristic pressure behavior of a naturally fractured reservoir becomes less pronounced as the variance of the matrix block size distribution increases.

REFERENCES

1. Warren, J.E. and Root, P.J.: "The Behavior of Naturally Fractured Reservoirs," Soc. Pet. Eng. J., September 1963.

2. Belani, A. and Jalali-Yazdi, Y.: "Estimation of Matrix Block Size Distribution and Fracture Intensity from Pressure Transient Data," paper SPE 18171, to be presented at the 63rd Annual Technical Conference & Exhibition of the Society of Petroleum Engineers, Houston, Texas, October 2-5, 1988.

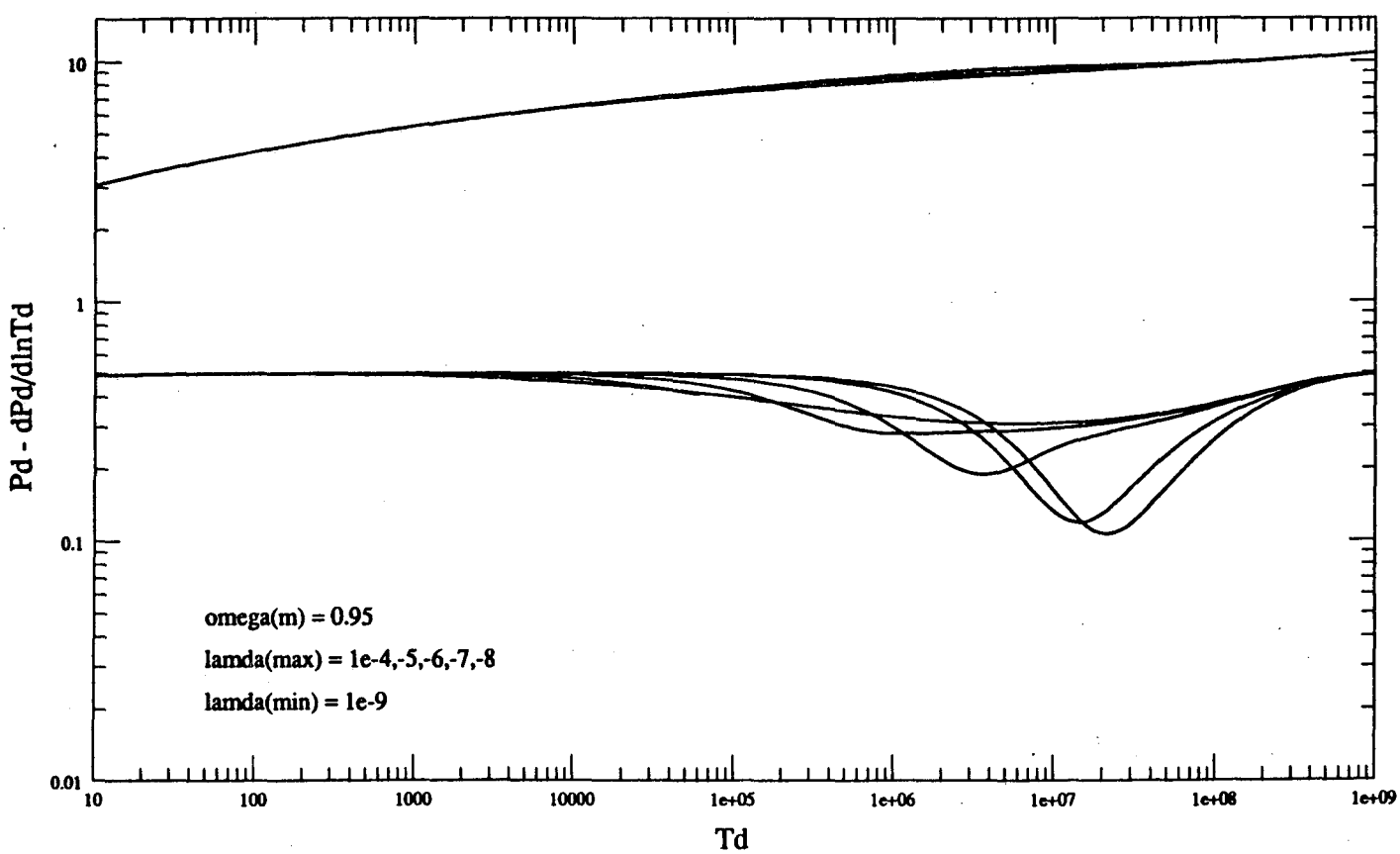


FIGURE 1

Uniform matrix block size distribution response versus single block size response

Geothermal Well Testing and Field Case Studies

Gudmundur S. Bodvarsson

Earth Sciences Division
Lawrence Berkeley Laboratory
University of California
Berkeley, California 94720

Abstract

Recent work on geothermal well testing and field case studies conducted at Lawrence Berkeley Laboratory (LBL) is reviewed. The work includes studies on internal well flow, relative contributions of feed zones, pressure transient testing and reservoir evaluation. New research findings are discussed and difficulties in data interpretation and analysis are identified.

Introduction

In the evaluation of geothermal reservoirs, various techniques and methods have been "borrowed" from the oil, gas and groundwater literature. However, these methods have limited applicability for geothermal reservoirs, which often are very thick, reside in fractured, volcanic rocks, and may contain fluids of temperatures up to 400 °C. The high temperatures cause difficulties in measuring downhole parameters needed to characterize the systems. Their large thickness and fractured nature complicates the analysis of temperature and pressure profiles, and pressure transient and geochemical data, as fluids enter or leave the well in only a few major permeable zones, and there is often internal well flow between these zones.

Current methods for evaluating the potential of geothermal systems employ numerical simulators and include a thorough analysis of the pre-exploitation conditions of the reservoir. Natural state models provide valuable information regarding the permeability structure and natural mass and heat flow, as well as providing proper initial conditions for exploitation modeling. For two-phase reservoirs, the exploitation models must represent each well individually in order to correctly reflect time-dependent changes in flow rates and fluid enthalpies. For some geothermal systems, high concentrations of dissolved solids and/or noncondensible gases must be included in the modeling effort.

Field case studies of geothermal fields have proved very valuable for our research efforts at Lawrence Berkeley Laboratory (LBL). These have allowed us to use some of the methodology developed through theoretical studies, to verify the usefulness of numerical simulators as field evaluation tools and to provide ideas for relevant research topics. To date our group has worked with data from over 20 U.S. and foreign geothermal fields.

In this paper various aspects of geothermal reservoir engineering are discussed, ranging from individual well characteristics, such as internal flow, to field-wide reservoir modeling and field case studies. Although new methods have been and are being developed to characterize geothermal systems, still there remains much research to be done until one can adequately characterize and evaluate geothermal reservoirs.

Internal Well Flow

One characteristic feature of many geothermal wells is that internal well flow occurs when the well is shut-in. Internal flow masks the true temperature of the formation and only permits determination of the static reservoir pressure at the depth of the predominant (highest permeability) feed zone. It also complicates the analysis of pressure transient test data.

Internal well flow is often caused by different pressure potentials in different reservoir aquifers. Figure 1 shows the pressures in different wells located at the Nesjavellir geothermal field in Iceland, and shows considerable pressure potential differences between aquifers (Stefansson, 1985; Bodvarsson et al., 1986b). Wells with significant permeabilities in two or more zones with different pressure potential will invariably have internal flow. However, even if the reservoir is vertically in pressure equilibrium, internal flow can still develop because of the different phase composition within the wellbore compared to that in the reservoir. This is especially true for wells completed in two-phase geothermal reservoirs.

The amount of fluid flow in wells with internal flow varies considerably and depends primarily upon the permeability of the less permeable feedzone (Ripperda and Bodvarsson, 1988). Internal flows on the order of several tens of kg/s have been measured in geothermal wells (Grant et al., 1982). Figure 2 shows a model developed for evaluating internal flow in geothermal wells that consists of two aquifers with different rock properties. Figure 3 shows the computed internal flow rate as a function of time for different aquifer transmissivities. The figure shows that internal flow rates on the order of 10 to 100 kg/s can be expected for high permeability wells (Ripperda and Bodvarsson, 1988).

It is of importance to determine the relative conditions of the feedzones in geothermal wells in order to select future drilling targets, to understand reservoir mass and heat flows and to properly interpret geochemical data collected at the wellhead. Spinner surveys have not been found very useful for this purpose, because of difficulties in operating the spinners and in interpreting the results in zones with rapidly changing phase compositions.

We have recently developed a multi-feedzone wellbore model that has given promising results for determining relative contributions of feedzones (Bjornsson, 1987; Bjornsson, and Bodvarsson, 1987). This model can be used to analyze

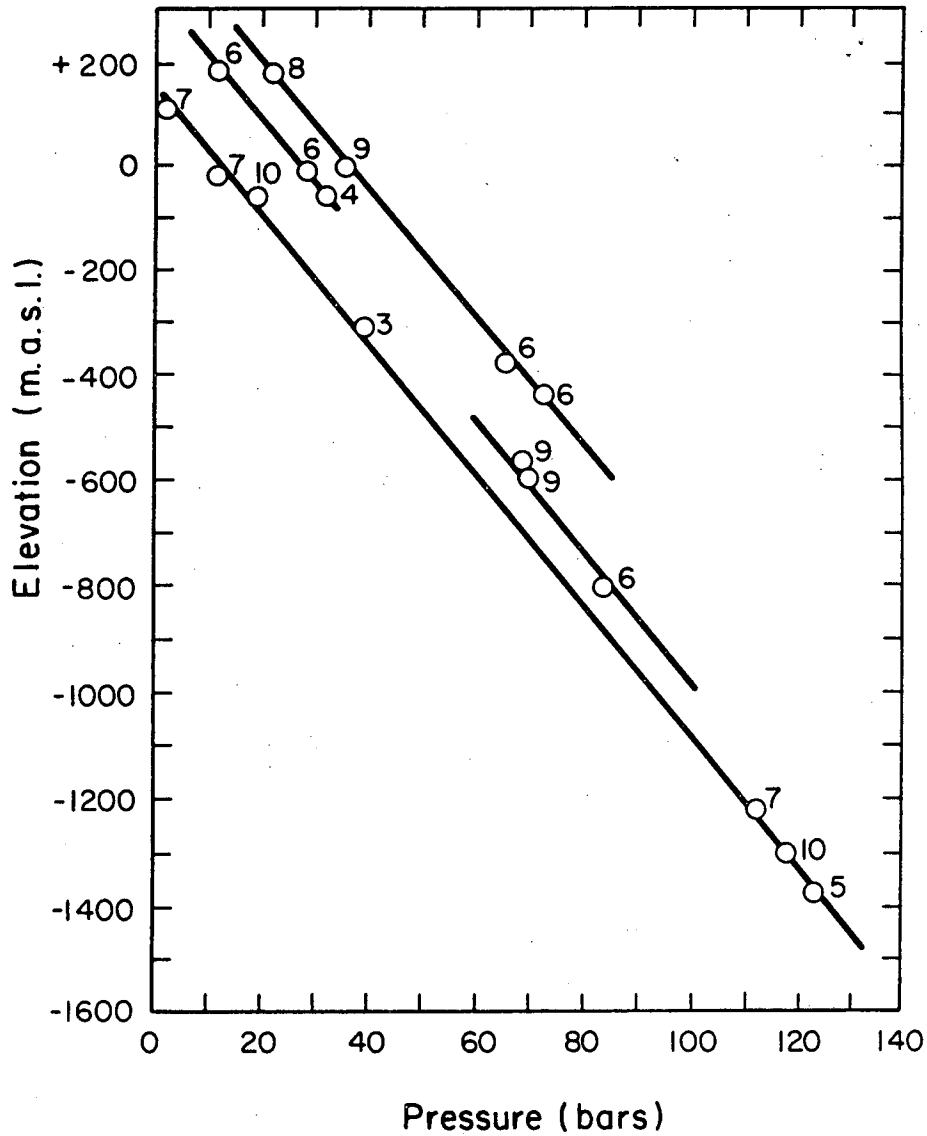


Figure 1. Pressures at major feedzones for wells at Nesjavellir, Iceland (after Stefansson, 1985).

flowing temperature and pressure surveys, as illustrated in Figure 4 for a well in the Olkaria geothermal field, Kenya. The analysis indicated two major feedzones at 900 and 1650 m depth, with the majority of the fluids entering the well through the shallow feed. A two-phase mixture of water and steam enters the well at the shallow feedzone (enthalpy of 1330 kJ/kg), but only liquid water is contributed by the lower feedzone. A minor downflow occurs in the well from the feedzone at 1650 m to a smaller feedzone at the bottom of the well (2000 m depth). The multi-feedzone model can also be used to evaluate internal flows in shut-in wells and can be coupled with a reservoir simulator to study exploitation and injection effects in geothermal systems.

Well Testing

Pressure transient tests are commonly performed in geothermal wells to determine the formation permeability-thickness product (transmissivity) and the well condition (skin effects). These tests are generally interpreted, with mixed success, using conventional isothermal well testing methods. For hot-water systems (single-phase), conventional interpretation of pressure drawdown and recovery tests usually yields reasonable results. For injection and falloff tests, nonisothermal conditions are present with associated variations in fluid properties; hence, a modified analysis procedure must be used (Bodvarsson and Tsang, 1980; Benson, 1982; Benson and Bodvarsson, 1986). This procedure involves determining the fluid properties that should be used in the analysis, and the correction of the apparent skin factor resulting from thermal skin effects. In some cases, interpretations of the late-time pressure transients during injection tests are complicated by permeability enhancement usually attributed to thermal cracking (Benson et al., 1987).

The analysis of pressure transient data from two-phase geothermal reservoirs has proven to be more difficult. Data from various fields have indicated inconsistencies in computed transmissivity obtained from various well test methods (injection, falloff, drawdown and recovery tests). Some of these inconsistencies may be due to thermal effects as discussed above, but most are related to two-phase effects.

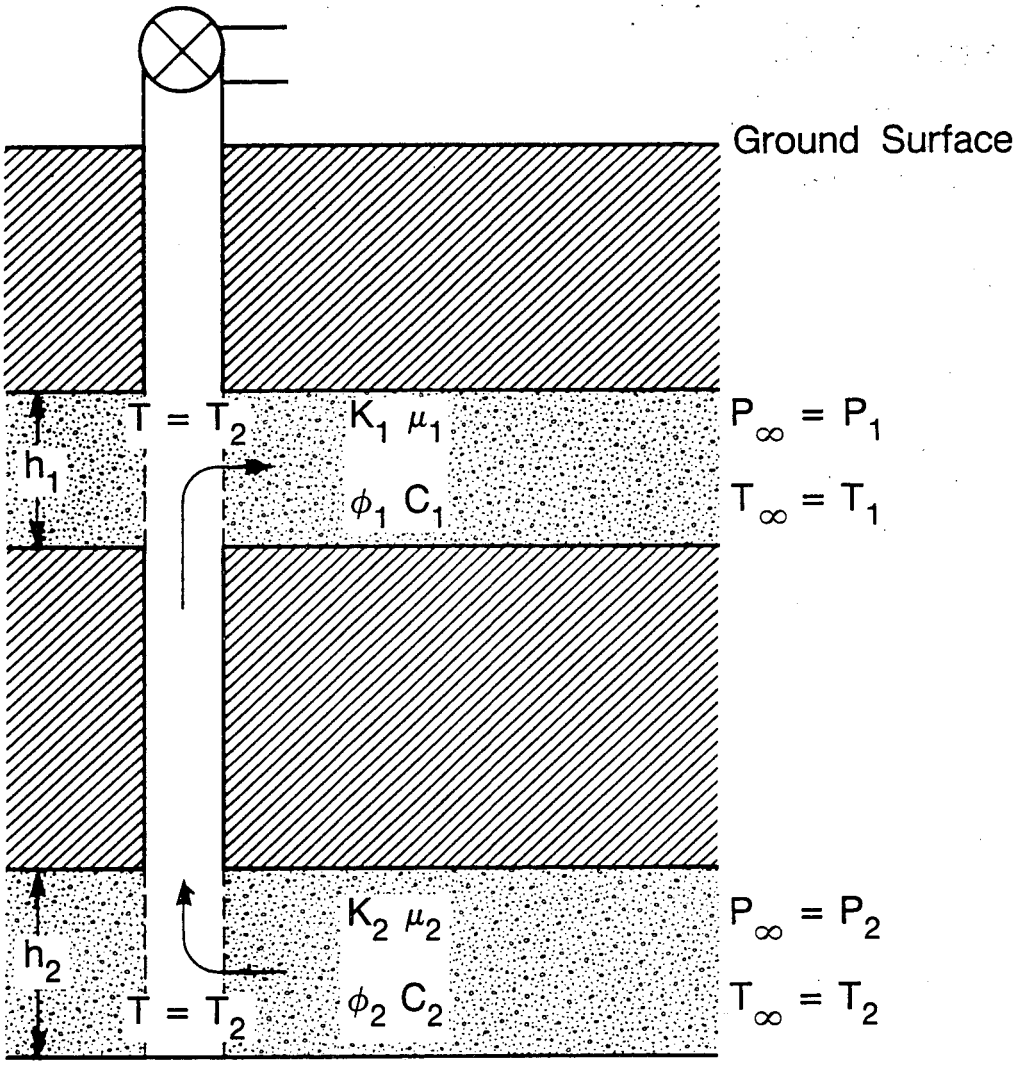


Figure 2. A model for evaluating internal flow in geothermal wells (after Ripperda and Bodvarsson, 1988).

Often, the pressure recovery (buildup) test data indicate transmissivity values that are considerably lower than those determined by the other test methods. This is due to internal well flow during recovery, which may persist for many years after the well has been shut in. Under this condition, pressure surveys will indicate that a permanent drawdown of tens of bars has occurred in deeper parts of the reservoir (Figure 5). Due to the internal flow, the well pressure adjacent to shallow feeds may become considerably higher than the original static pressure. An example of this is well OW-26 in the Olkaria geothermal field, Kenya, which showed an apparent permanent drawdown of 20-30 bars due to internal well flow.

Interference tests are generally performed in geothermal fields, and the calculated transmissivities, when compared to those obtained from individual well tests, are sometimes more than an order of magnitude higher (Grant et al., 1982). In most cases, the interference test results are considered more reliable average values for the field, since the reservoir volume affected by the interference tests is much greater than that tested with short-term individual well tests. However, there is growing evidence that the discrepancy between interference test results and those for individual well tests is simply due to the conventional analysis methods being used. Geothermal reservoirs are located in heterogeneous fractured rocks, so that analysis methods that assume uniform permeabilities are rarely applicable. Flow to geothermal wells occurs through distinct channels. If only a small fraction of the total fluids produced flows through the channel connecting the production and observation wells, then pressure interference is diminished, and conventional analysis yields transmissivity values that are far too high. In order to determine the proper rate to assign to a given observation well in the analysis, tracer tests must be conducted along with pressure tests. It appears now that transmissivities determined from individual well tests give the most accurate representation of the average reservoir transmissivity.

Another problem with interference tests in two-phase systems involves the effect of steam-water counterflow that is enhanced by boiling near the production wells (Bodvarsson and Cox, 1986). Because of the enhanced counterflow, the pressure in observation wells with shallow feeds may not decline according to single-phase pressure transient theory, but may actually increase. The increased upflow of steam during production will cause steam condensation below the caprock, therefore, increasing temperatures, and consequently,

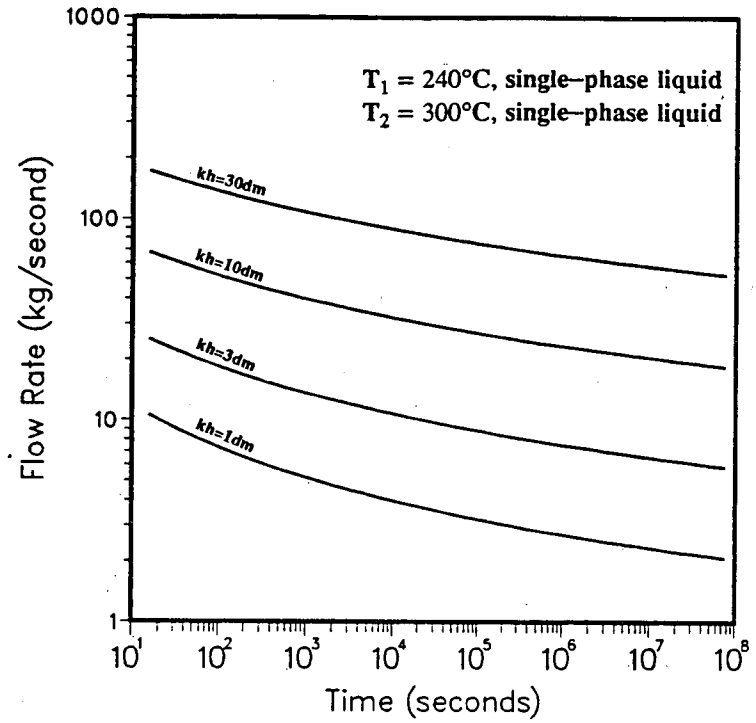


Figure 3. Computed internal flow rate as a function of time for various aquifer transmissivities (after Ripperda and Bodvarsson, 1988).

pressures.

Under these conditions, pressure increases in shallow observation wells cannot be analyzed to yield the average horizontal transmissivity of the formation. Instead, it can provide information on the effective vertical permeability to the steam phase (Bodvarsson et al., 1987a). Thus, in order to properly interpret interference tests in two-phase reservoirs, the depth of the major feedzone in the observation wells must be considered.

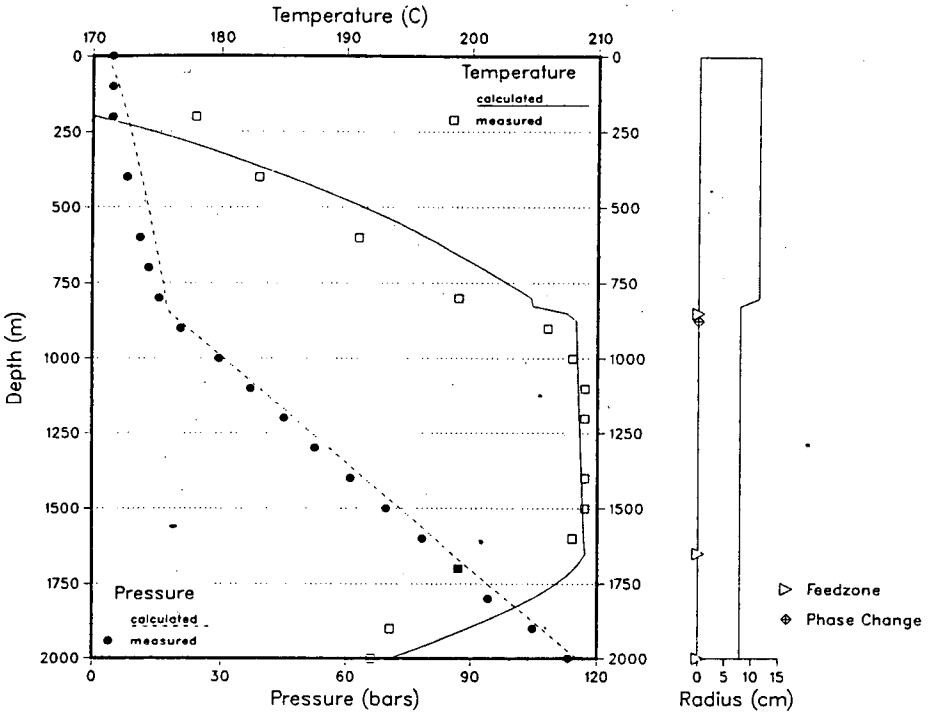
Although many complications are evident in well testing of two-phase geothermal reservoirs, very important information can be obtained from simultaneous measurements of pressure transients, enthalpy changes and variations in non-condensible gases during a production test. As an example, Figure 6 shows data from well BR-21 in Broadlands (Ohaaki), New Zealand (Grant and Glover, 1985). These data were matched by numerical simulations (Gaulke and Bodvarsson, 1987) using the methods of "multiple interacting continua" (MINC; Pruess and Narasimhan, 1985) and LBL's general-purpose simulator MULKOM (Pruess, 1983). The match allowed for determination of important reservoir parameters, including fracture porosity and transmissivity, gas saturation and partial CO_2 pressure in fractures and rock matrix, and recharge from the matrix blocks. This example shows that multi-component well tests can give much more information on reservoir characteristics and conditions than pressure transient tests alone.

RESERVOIR EVALUATION

Various methods have been employed in evaluating the potential of geothermal reservoirs for electrical power production or space heating purposes (Bodvarsson et al., 1986a). The simplest approach uses volumetric methods for estimating the recoverable energy fraction. This method is useful in the early stages of a project, but lacks the capability to consider important well data such as reservoir permeabilities, productivities of wells and information regarding the pressure decline. Lumped-parameter models can take into account average reservoir parameters, but neglect spatial variations both in thermodynamic conditions and reservoir properties and can therefore only provide first-order estimates for the reservoir potential.

Numerical simulators can provide the most detailed and reliable evaluation of geothermal systems because of their flexibility to consider all of the most important reservoir and well data available. The use of such models has progressed rapidly in recent years to the extent that many of the important aspects of geothermal systems that must be considered have been identified (Bodvarsson et al., 1986a). One of the essential elements of a modeling effort involves modeling the behavior of the system in its natural (pre-exploitation) state (Figure 7). This model not only provides the essential initial conditions for exploitation modeling, but also provides estimates for the permeability structure of the resource and natural flow of mass and energy through the system.

Several different approaches have been used in the modeling of geothermal fields under exploitation, including the lumped-wellfield approach and well-by-well models. The lumped-wellfield approach involves incorporating the entire wellfield into one or a few grid blocks and computing average flow rates and enthalpies. In many cases, especially for two-phase reservoirs, this approach is of limited use because of widely different characteristics exhibited by the wells. In order to represent these large variations, the wells must be modeled individually and the computed flow rate and



Olkaria, well OW-201
Wellbore calculations during discharge
Measurements from 22-oct-1984

Wellhead pressure (bar abs.)	:	3.00
Wellhead temperature (C)	:	133.54
Wellhead dryness	:	0.332
Wellhead enthalpy (kJ/kg)	:	1280.00
Wellhead total flow (kg/s)	:	35.50

Feedzone no:	Depth (m)	Flow (kg/s)	Enthalpy (kJ/kg)
1	850.0	33.0000	1330.0
2	1650.0	2.8000	901.6
3	2000.0	-0.3000	827.7

Figure 4. Calculated and measured downhole profiles in well OW-201 at Olkaria, Kenya (after Bjornsson, 1987).

enthalpy behavior matched to the observed data. This is referred to as the well-by-well representation, and has been successfully applied to various geothermal fields, including Krafla, Iceland (Pruess et al., 1984), and Olkaria, Kenya (Bodvarsson et al., 1987b). This approach yields performance predictions for all of the wells individually, so that direct comparison between predicted results and future observations is possible.

As shown in Figure 7, the most reliable model should result if one iterates between the natural state model and the exploitation model. This allows verification of the consistency between all changes in reservoir parameters and the initial thermodynamic state, well test results, and production history. Often, many iterations are required until a final model evolves that is consistent with all available data.

For many geothermal reservoirs, the salinity of fluid is sufficiently low that it can be approximated using properties for pure water. However, some geothermal reservoirs contain large concentrations of dissolved solids and noncondensible gases, primarily CO_2. These constituents can alter the phase composition and other thermophysical properties of reservoir fluids, and thereby significantly affect reservoir response to exploitation. As an example, the presence on noncondensible gases can perturb the usual one-way flow from the matrix blocks to the fractures, yielding at late times "backflow" from the fractures to the matrix blocks (Figure 8; Gaulke. 1986; Bodvarsson and Gaulke, 1987). The backflow develops from temperature gradients between the fluids in the fractures and matrix blocks, and can significantly reduce the overall mass recovery from the system.

FIELD CASE STUDIES

An integral part of LBL geothermal research efforts has been comprehensive field case studies. The DOE-CFE cooperative study in Cerro Prieto, Mexico, is a classic example. Field case studies have allowed us to verify theoretical findings, demonstrate the usefulness of numerical modeling and has helped identify research problems that require solutions. We are currently conducting cooperative field case studies with colleagues in Mexico, Iceland, Kenya, and El Salvador.

Recently, LBL has started cooperative work with the

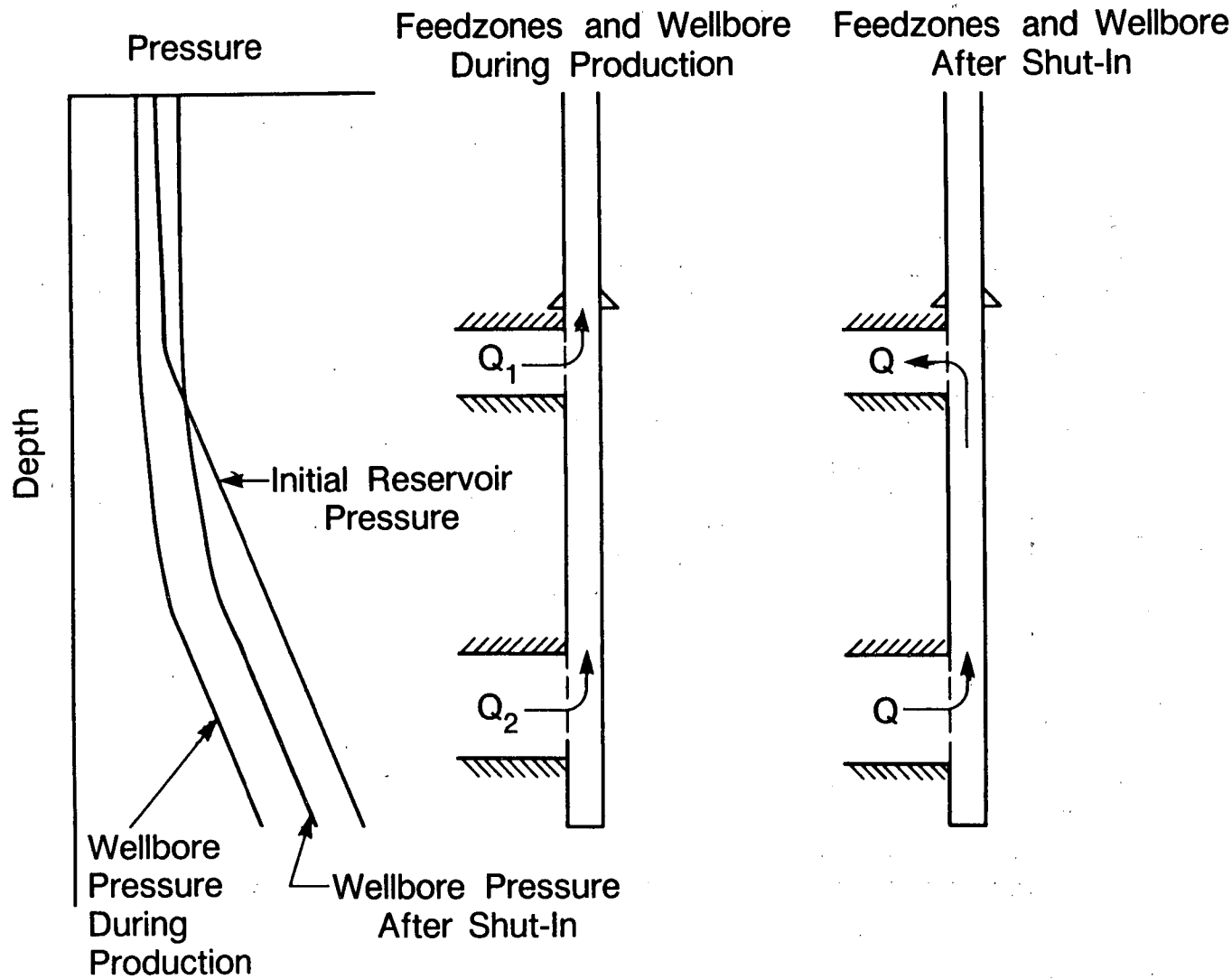


Figure 5. Schematic pressure profiles in a well under shut-in and flowing conditions (after Ripperda and Bodvarsson, 1988).

Philippine National Oil Company (PNOC) involving exchange of scientists and field data. The geothermal field of special interest in the Philippines is Palinpinon in Southern Negros, because of the excellent field data collected, especially regarding reinjection. Figure 9 shows the changes in chloride concentration of many of the producers in Palinpinon, illustrating chloride increases due to returns of the reinjected fluids. Figure 10 shows the percentage returns of reinjected fluids in various wells based on the chloride data (Harper and Jordan, 1985). The geochemical data indicate that some of the reinjected fluids have circulated several times through the reservoir. The analysis of the data shown in Figures 9 and 10, augmented by geologic (fault patterns) well test and production data, should give valuable insights into the movement of "cold" injection fluids. It is hoped that a detailed study of this data set will allow for some correlations between chemical and thermal fronts to be developed. In recent years may theoretical studies have focused on this problem, but the lack of available (open file) reinjection data has prohibited much progress to be made. The results of the Philippine study should be of great value to U.S. developers, as reinjection is utilized in most of their geothermal fields.

ACKNOWLEDGEMENTS

This work was supported by the U.S. Department of Energy under Contract No. DE-AC03-76SF00098 by the Assistant Secretary for Conservation and Renewable Energy, Office of Renewable Technology, Division of Geothermal Technologies.

REFERENCES

Benson, S. M., 1982, Interpretation of nonisothermal step-rate injection tests, Proc. 8th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, pp. 103-110.

Benson, S. M., Daggett J. S., Iglesias, E., Arellano, V. and Ortiz-Ramirez, J., 1987, Analysis of thermally induced permeability enhancement in geothermal injection wells, Proc. 12th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, pp. 57-66.

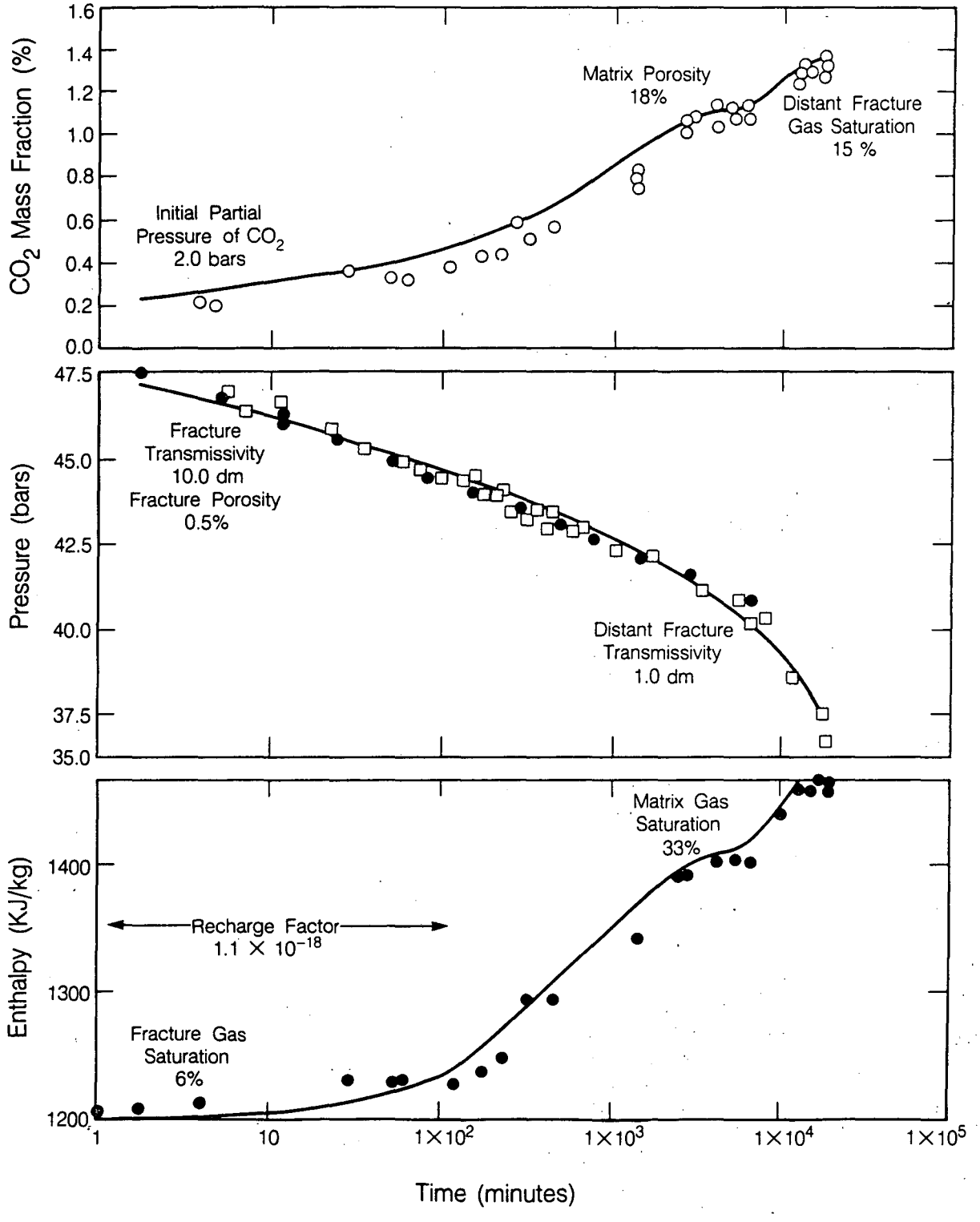


Figure 6. Pressure, enthalpy and CO_2 transients for well BR-21 at Ohaaki, New Zealand. The solid lines show the best match obtained through numerical simulations (after Gaulke, 1986).

Benson, S. M. and Bodvarsson, G. S., 1986, Nonisothermal effects during injection and falloff tests, *SPE Formation Evaluation,* Vol. 1, No. 1, pp. 53-63.

Bjornsson, G., 1987, A multi-feedzone wellbore simulator, M.S. Thesis, University of California, Berkeley, CA, LBL-23456.

Bjornsson, G. and Bodvarsson, G. S., 1987, A multi-feedzone wellbore simulator, *Trans. Geothermal Resources Council,* Vol. 11, pp. 503-508.

Bodvarsson, G. S. and Cox, B. L., 1986, Numerical studies of gravity effects in two phase reservoirs, *Trans. Geo. Resour. Council,* Vol. 10, pp. 429-436, LBL-21935.

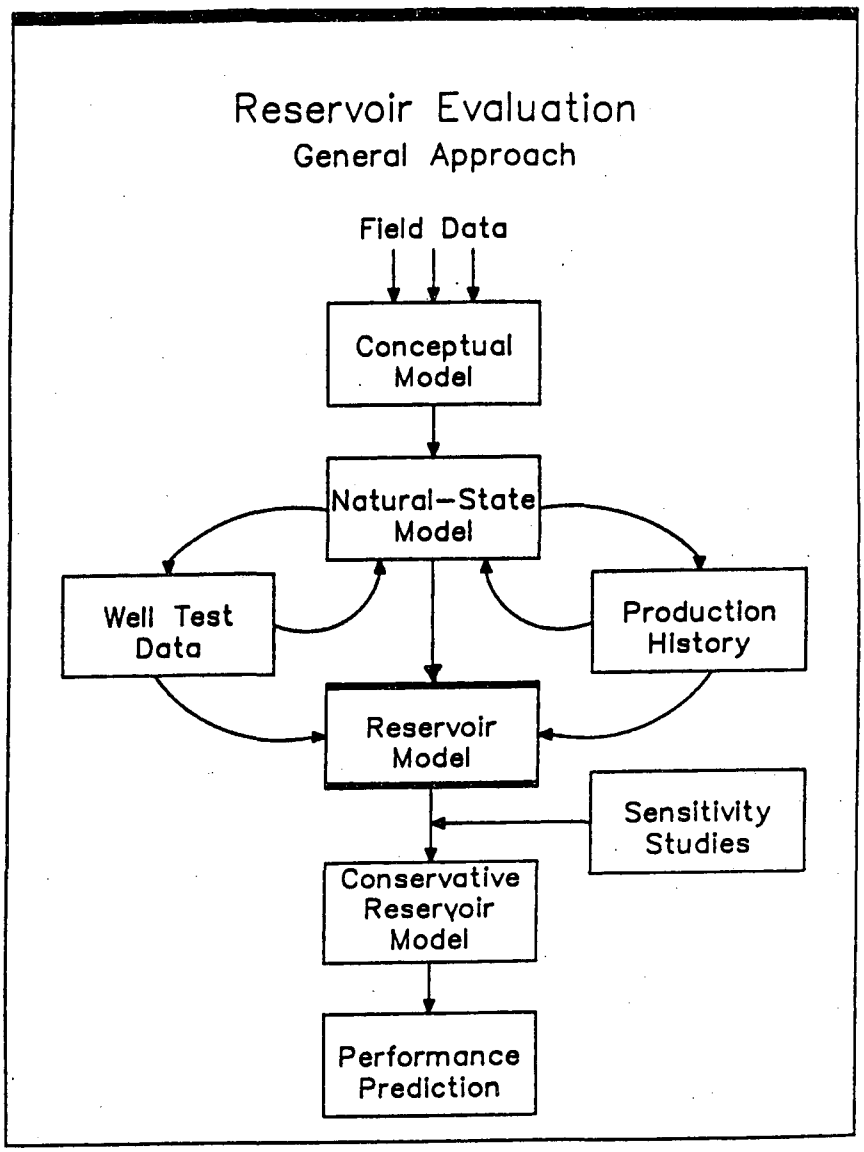


Figure 7. General approach to reservoir evaluation.

Bodvarsson, G. S., Cox, B. L. and Ripperda, M., 1987a, Effects of steam-liquid counterflow on pressure transient data from two-phase geothermal reservoirs, SPE-16775, *SPE Reservoir Eng. Jour.*, in press.

Bodvarsson, G. S. and Gaulke, S., 1987, Effects of noncondensible gases on fluid recovery in fractured geothermal reservoirs, *SPE Reservoir Eng. Jour.*, Vol. 2, No. 3, pp. 335-342, LBL-21112.

Bodvarsson, G. S., Pruess, K. and Lippmann, M. J., 1986a, Modeling of geothermal systems, *Jour. Pet. Tech.*, Vol. 38, No. 10, pp. 1007-1021, LBL-18268.

Bodvarsson, G. S., Pruess, K., Stefansson, V., Bjornsson, G. and Ojiambo, S. B., 1987b, The East Olkaria geothermal field, Kenya, 1. History match with production and pressure decline data, *Jour. Geophys. Res.*, Vol. 92, No. B1, pp. 521-539, LBL-20098.

Bodvarsson, G. S., Pruess, K., Stefansson, V., Steingrimsson, B., Bjornsson, S., Gunnarssow, A. and Gunnlaugsson, E., 1986b, Natural State model of the Nesjavellir geothermal field, Iceland, Proc. 11th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, pp. 109-115.

Bodvarsson, G. S. and Tsang, C. F., 1980, Thermal effects in the analysis of fractured reservoirs, Proc. 3rd Invitational Well Testing Symposium, Lawrence Berkeley Laboratory, Berkeley, CA, LBL-12076, pp. 110-119.

Gaulke, S., 1986, The effects of CO_2 on reservoir behavior of geothermal systems, M.S. Thesis, University of California, Berkeley, CA, 150 p.

Gaulke, S. and Bodvarsson, G. S., 1987, Analysis of pressure, enthalpy and CO_2 transients in well BR-21, Ohaaki, New Zealand, *Trans. Geo. Resour. Council*, Vol. 11, pp. 535-540.

Grant, M. A., Donaldson, I. G. and Bixley, P. F., 1982, Geothermal reservoir engineering, Academic Press, 369 p.

Grant, M. A. and Glover, R., 1985, Two-phase heat and mass transfer experiment at well BR-21, Broadlands, New

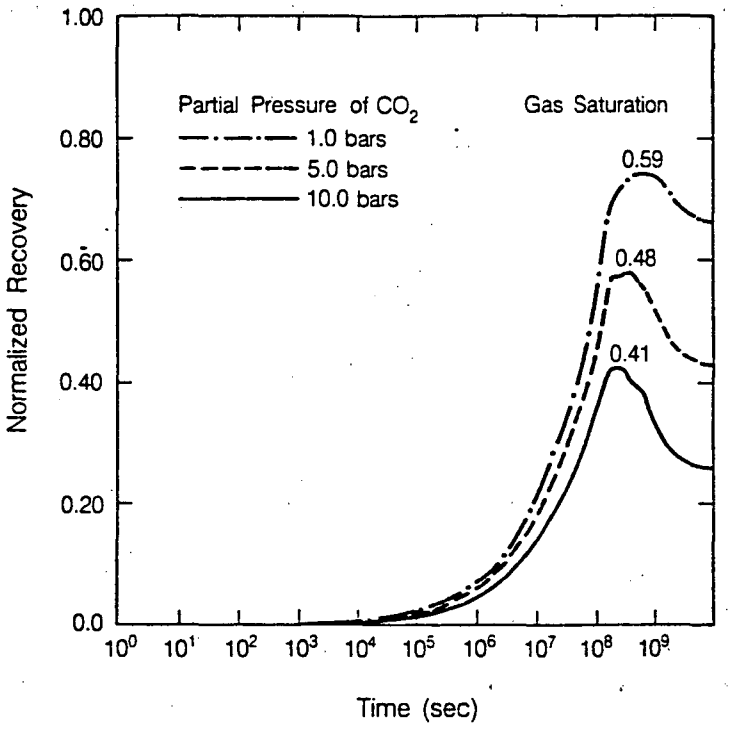


Figure 8. Computed normalized mass loss from a matrix block as a function of time for various initial partial pressures of CO_2 (after Gaulke, 1986).

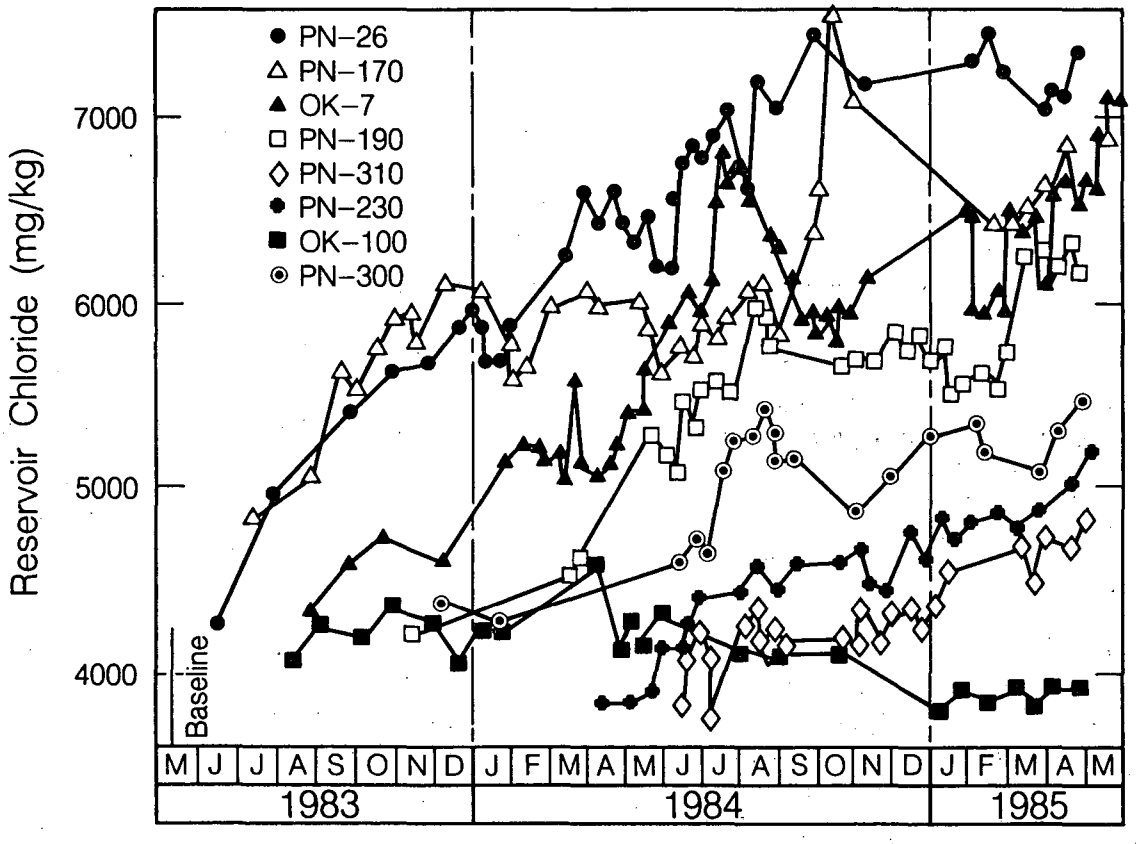


Figure 9. Changes in Chloride concentration with time for Palinpinon wells (after Harper and Jordan, 1985).

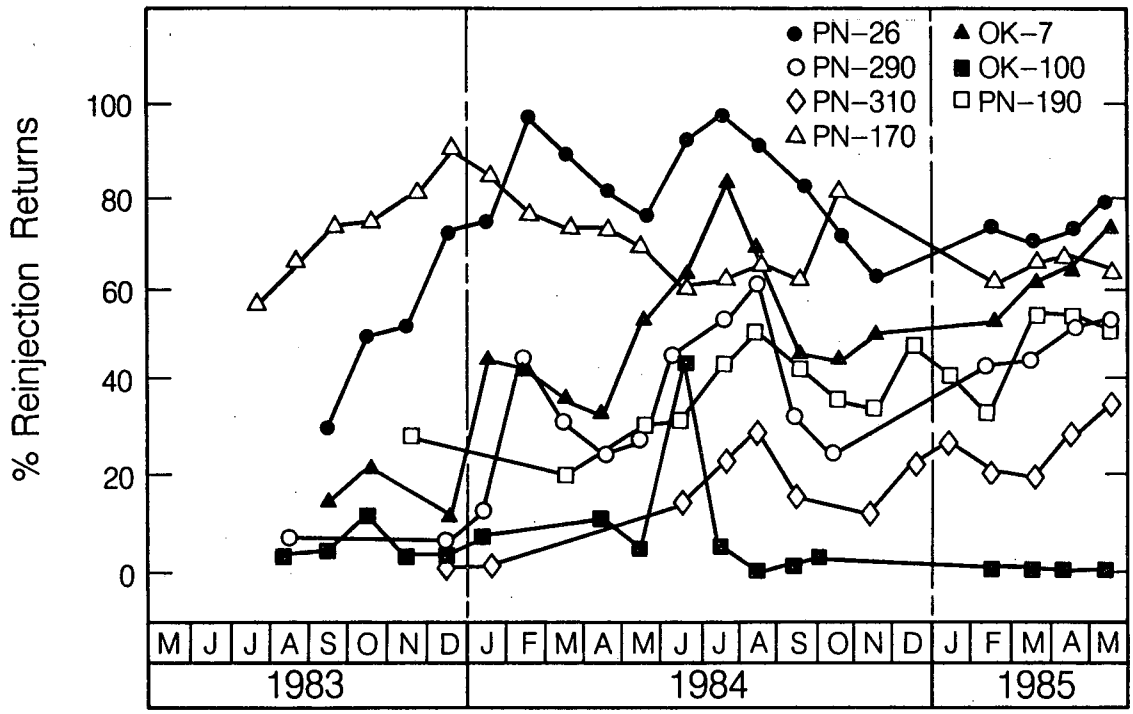


Figure 10. Estimated percentage returns of reinjected water for Palinpinon wells (after Harper and Jordan, 1985).

Zealand, *Geothermics,* Vol. 13, No. 3, pp. 193-213.

Harper, R. T. and Jordan, O. T., 1985, Geochemical changes in response to production and reinjection for Palinpinon - 1 geothermal field, Negros Oriental, Philippines, Proc. 7th New Zealand Geothermal Workshop, Auckland, New Zealand, pp. 39-44.

Pruess, K., 1983, Development of the general purpose simulator MULKOM, 1982 Annual Report, Earth Sciences Division, Lawrence Berkeley Laboratory, Berkeley, CA, LBL-15500, pp. 133-134.

Pruess, K., Bodvarsson, G. S., Stefansson, V. and Eliasson, E. T., 1984, The Krafla geothermal field, Iceland, 4. History match and prediction of individual well performance, *Water Resour. Res.,* Vol. 20, No. 11, pp. 1161-1584.

Pruess, K. and Narasimhan, T. N., 1985, A practical method for modeling fluid and heat flow in fractured porous media, *Soc. Pet. Engr. Jour.,* Vol. 25, No. 1, pp. 14-26.

Ripperda, M. A. and Bodvarsson, G. S., 1988, Analysis of internal wellbore flow, Proc. 13th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, Jan. 19-21, 1988, (in press).

Stefansson, V., 1985, The Nesjavellir high-temperature geothermal field in Iceland, Proc. 10th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, pp. 23-30.

FRACSL RESEARCH: PAST, CURRENT AND FUTURE

John D. Miller and Tom M. Clemo
Idaho National Engineering Laboratory

ABSTRACT

The Idaho National Engineering Laboratory (INEL) is developing the FRACSL code to simulate flow, solute transport, and heat transport in a saturated fractured-porous media. The code uses a dual permeability approach in which a common head distribution drives flow in rectangular matrix cells and in discrete fractures which lie on the edges and diagonals of the matrix cells. Solute and heat transport are modeled by moving marker particles in the matrix, in the fractures and between the two. The code has been developed in conjunction with laboratory, field and numerical studies. Work is in progress comparing FRACSL to other codes on analytic and fully complex problems in flow, solute transport and heat transport. In addition, the code is being prepared for transfer to industry in a hands-on training session. Future work is anticipated to include the completion of laboratory validation, the extension to 3D and the staging of models up to reservoir scale. A small scale field validation would be performed using an existing data set. Finally, we propose to evaluate the FRACSL code and the other discrete fracture characterization and modeling technology which is being developed in the Reservoir Technology Program by means of a reservoir scale test and correlation. FRACSL, other discrete fracture codes and an equivalent porous media code would be used to predict reservoir performance and tracer transport for three different data sets: standard logging practice, relogging using the best available technology and relogging plus drilling and coring a new well near an existing one. Fracture mapping, cross-borehole tomography, and flow and tracer testing would be performed between the two adjacent wells. The results of the demonstration would be a determination of the capabilities, benefits and cost of the advanced methods.

INTRODUCTION

The movement of injected fluid in a fractured reservoir is being modeled in response to a primary industry concern about the effect of injection on pressure maintenance, thermal breakthrough, and water-rock interaction in a producing reservoir. Fractures and matrix are modeled explicitly to provide the most physically realistic models and potentially the most accurate tool for studying the movement of injected and produced fluids. The merit of this approach can be established by providing answers to two fundamental questions: First, can the media be characterized well enough to support this approach? Second, is there sufficient improvement in predicting reservoir behavior to warrant the additional expense? These questions can be answered by the reservoir scale demonstration proposed at the end of this discussion.

The material in this paper describes the FRACSL approach, capabilities, results to date, work-in-progress and future work, including the work needed before the reservoir scale validation can be performed.

APPROACH

FRACSL (Miller et al., 1987) provides a two-dimensional simulation of flow, solute transport and heat transport in a saturated, fractured-porous media. As shown in Figure 1, a distributed flow is computed through the porous matrix cells and a discrete flow is computed in the parallel plate fractures superimposed on the edges and diagonals of the matrix cells. This approach, termed dual permeability, is different from dual porosity in which flow is computed in the fractures and a one-dimensional interchange occurs with the storage in the adjacent matrix. In dual permeability a flow can be computed from fracture to fracture through intervening matrix and in dual porosity modeling it cannot.

The marker particle transport approach used in FRACSL is ideally suited to dual-permeability models since it permits explicitly addressing the fractures, the matrix, and the interchange between them in terms of the fundamental physical processes of advection, dispersion, and diffusion.

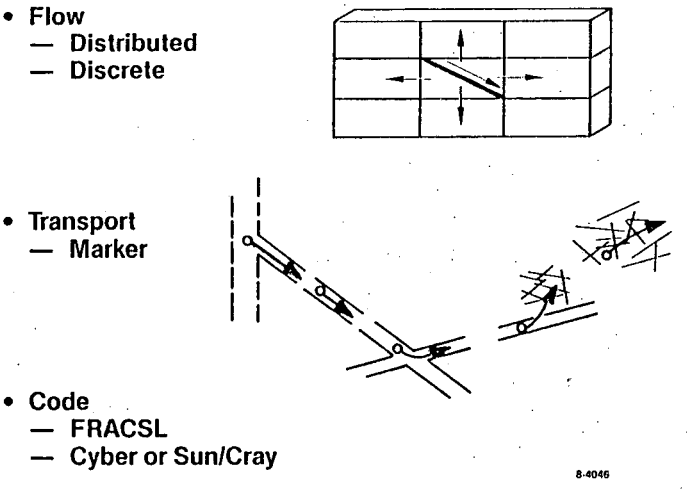


Figure 1. FRACSL approach: matrix dual permeability.

Particles are "tagged" with specified amounts of solute or energy and are moved from the injection well into the various connecting fractures or matrix according to the flow distribution.

Movement within a fracture is computed based on random diffusion plus the longitudinal and transverse fluid velocities at the particle lateral position. The longitudinal velocity is selected from a Poiseuille distribution across the fracture aperture while the transverse velocity depends on the fluid movement from fracture to matrix due to advection across the matrix cell and storage within it. At a junction with another fracture the particle moves into the appropriate exit fracture by advection along a stream line plus a random diffusive movement.

Particle transfers between fracture and matrix are computed due to advection and diffusion. For diffusively dominated conditions, the random walk approach used excessive amounts of computer time since a particle moving into the matrix has a 50% chance of moving back into the fracture in the next time step. A higher order model was, therefore, developed which determines the particle motion based on overall probability.

This model is used when the fracture Peclet number (P_e) is greater than 200.

$$Pe = \frac{210\, D_m\, L}{vb^2}$$

where

D_m	=	molecular diffusion coefficient	$(\frac{L^2}{T})$
L	=	length	(L)
v	=	velocity	$(\frac{L}{T})$
b	=	aperture	(L)

Particle movement within the matrix is computed as the sum of advective, dispersive and diffusive motions.

Solute concentration or temperature within the model is computed from the distribution of particles at any particular time. Concentration or temperature is also monitored at a production well node.

The original version of FRACSL uses the Advanced Continuous Simulation Language (ACSL, Mitchell and Gauthier Assoc., 1986) for its user interface and numerics and is implemented on the INEL CDC Cyber 176 computer. This version is being phased out and the work load transferred to a UNIX based version with self-contained numerics. The new version is operable on a SUN or equivalent workstation for field applications and on the INEL CRAY X-MP/24 computer for more complex research simulations. In addition to the wider availability, the new version does not incur the cost and the separate documentation of the ACSL software. It also provides sparse matrix capabilities which increase the number of nodes which can be handled on a given computer.

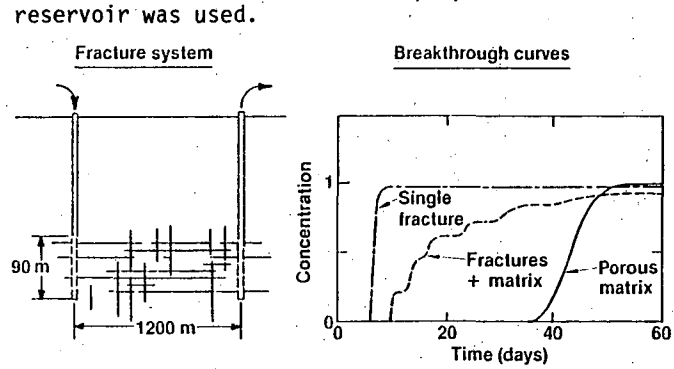
RESULTS

The FRACSL code has been developed in conjunction with laboratory, field, and numerical studies.

The laboratory studies were conducted to gain an understanding of basic fluid processes and to furnish controlled environments for validating the code. Studies have been conducted of tracer movement in fracture junctions (Hull and Koslow, 1986) and in systems of fractures (Hull, et. al., 1987). In addition, the dual permeability model shown in Figure 2 has been tested to provide the basis for a complete correlation of the FRACSL code (Hull and Clemo, 1987a). The model consists of a thick slab of porous polyethylene which has a porosity of 37%. The model was sawed to create the system of continuous and dead ended fractures shown in the figure. After encasing the model in plastic, a background flow was established from left to right. A dye was injected near the upper left corner of the model and was swept to the right by the background flow. The upper sketch shows the position of the dye plume at 150 minutes, and the lower plot shows the corresponding predicted marker particle positions. Qualitative agreement was obtained with solute concentration as measured by electrodes placed in the fractures and in the matrix.

Field studies were conducted with University of Utah Research Institute (UURI) at Raft River, Idaho (Large, 1983), and East Mesa, California (Freiburger, 1984). Single well injection backflow tests were conducted to study the flow and tracer characteristics of the media in the immediate vicinity of the well. FRACSL studies of these results were reported by Miller et al. (1984) and Clemo and Miller (1984).

Predictions of reservoir scale dispersion were made to assist UURI in determining tracer injection schedules for a forthcoming test at Dixie Valley, Nevada (Miller, 1988). An isothermal model with uniform properties over the reservoir was used.



From Hull and Clemo, 1987

Figure 2. Media transport characteristics.

Cooperative research on a fractured reservoir is to be started with the Comision Federale de Electricat (CFE) later this year.

Numerical studies have been performed to show the sensitivity of predicted tracer response to media characteristics. In the FRACSL study shown in Figure 3 (Hull and Clemo, 1987b), an injection well and a production well were connected by various media, all with a common transmissivity. Tracer was injected into the injection well and monitored at the production well to yield, the recovery-time curves shown on the right. The single fracture has the earliest arrival and a near step-like response. The porous media response is the slowest and has the classic sigmoidal shape. The fractured-porous media response has an intermediate arrival time and shows the rapid early rise and the long tail characteristic of this media. The study points out the importance of media characterization and the technique used to model flow and transport in that media. This approach was used in the Dixie Valley prediction discussed earlier in which porous matrix and fractured-porous matrix models were used to bound the range of expected tracer responses.

CURRENT RESEARCH

Work in progress is largely directed at evaluating FRACSL capabilities and preparing the code for transfer to industry.

FRACSL is being compared to MAGNUM-2D (England et al., 1985) plus CHAINT (Kline et al., 1985), TOUGH (Pruess, 1987), and other codes as time permits. MAGNUM-2D is a finite-element code for transient or steady-state simulation of coupled heat transfer and groundwater flow in a fractured porous media. Triangular and quadrilateral finite elements are used to represent the continuum portions of the spatial domain and line elements are used to represent discrete conduits. CHAINT simulates transport in the velocity field determined by MAGNUM-2D. TOUGH is the variant of the SHAFT 79 and MULKOM family which is available for basic geothermal

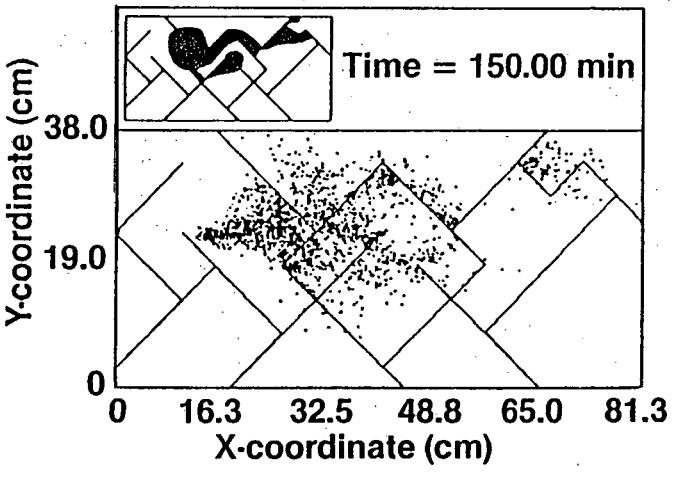


Figure 3. Dual permeability correlation.

simulations without requiring an intimate familiarity with the source code. Fractured-porous media are simulated using the "multiple interacting continua" (MINC) technique.

The comparison problems are simple verification cases for which there are analytic solutions and fully complex field problems for which there are no analytic solutions. The problems include flow, solute transport, and heat transport.

The UNIX based version of FRACSL is being prepared for transfer to industry at a hands-on training session, which will probably be held in November or December in the San Francisco Bay area. A comprehensive user's manual will be prepared and transmitted to potential users along with the code comparison report.

FUTURE RESEARCH

Future work consists of completion of capabilities for staged and 3D models, laboratory and field validations, and a proposed evaluation of discrete fracture characterization and modeling technology.

Work presented by Miller and Clemo (1988) showed an approach for staging models up to reservoir scale to include the porous matrix and the complete range of fracture size. The sketch at the center of Figure 4 shows a FRACSL matrix dual permeability model in which the grid cell (distributed element), shown enlarged on the right, is porous matrix. Since individual path lengths in the porous matrix are small compared to the element size, Darcian flow and Fickian transport models are appropriate. This distributed element is integrated with the smaller fractures in the FRACSL matrix dual permeability model. This model cannot be used at reservoir scale because of the number of fractures involved. It is, therefore, desirable to use the FRACSL model as the distributed element of a larger scale model. However, as shown in Figure 3, a volume of fractured porous material cannot be modeled using a porous media approach. The numerical technique given by Miller and Clemo involves determining the overall flow and transport properties of the FRACSL model and using these as the distributed element of a reservoir scale simulation along with the larger fractures. Analytic studies of these properties have been given by Clemo (1987).

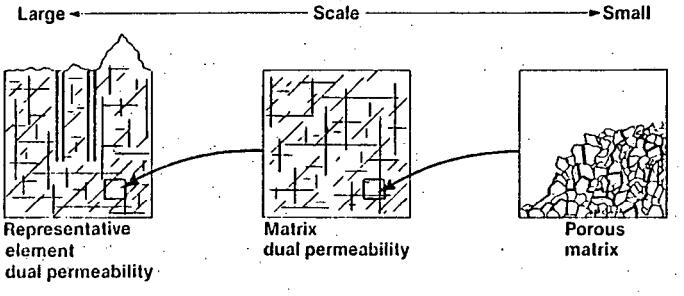


Figure 4. Staged models.

A three-dimensional dual-permeability flow code has been developed by Miller and Allman (1986). As shown in Figure 5, three sets of parallel disc shaped fractures are synthesized within a 3-dimensional model space. Discrete fracture flow is computed in fracture planes between intersections with other fractures. Distributed flow is computed between parallel planes of the same set in the region of overlap. The conductivity of the distributed regions is found from subscale models, one for each fracture set, which include the smaller fractures in the three sets. Future work will validate this flow model and add marker transport models.

After completion of this work, the 3-D model will be validated against a previous field scale flow and tracer test, probably from an existing repository study.

This work will prepare the FRACSL code for the proposed reservoir scale technology evaluation. This study will involve participation by the labs involved in the hydrothermal program and an industrial partner. The objective of the study is to evaluate the improvement in predictions of reservoir behavior through the use of advanced characterization and modeling techniques. The ideal reservoir for this study would be shallow, moderate temperature, liquid dominated, and extensively fractured and having multiple injection and production wells.

The study will involve predicting a reservoir scale tracer test on the basis of three data sets of increasing sophistication. The predictions would involve FRACSL and other codes including a simple equivalent porous media code. The first data set would be that already existing for the field and assumed to be typical of standard industrial practice. The second would involve relogging the wells using the best available geothermal tools and those high-level waste repository tools which can be adapted to the geothermal environment.

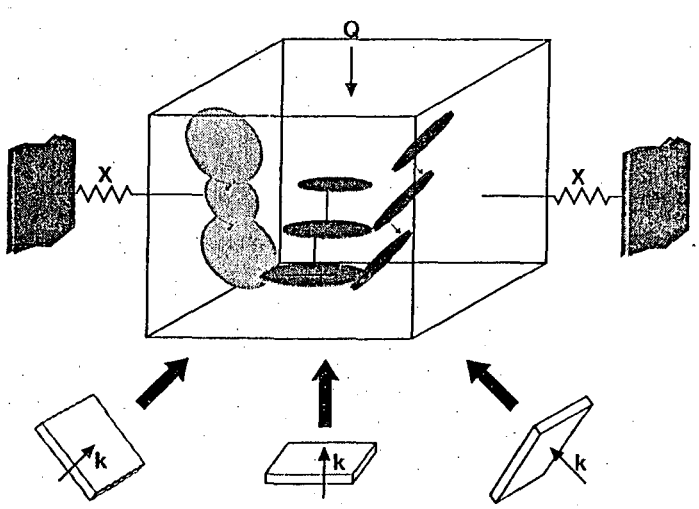


Figure 5. FRACSL-3D.

The third data set consists of set two plus the additional data gained by drilling, coring, and testing a new borehole near an existing one. The separation of the two boreholes would be such that applying geometric probability to the continuity of fractures across the two boreholes would provide an estimate of the distribution of fracture extent. Cross-bore tomography would be performed and flow and tracer testing would be conducted using packers to isolate single connecting fractures. This cross borehole testing provides data which cannot be obtained in any other manner and is essential to predicting the behavior of the media.

Correlation of the various predictions with the reservoir scale tracer testing would show the efficacy of available characterization techniques and the relative merit of the various predictive techniques relative to their costs.

REFERENCES

Clemo, T. M., "Representative Elements, A Step to Large Scale Fracture System Simulation," Proceedings: DOE/AECL 1987 Conference on Geostatistical, Sensitivity, and Uncertainty Methods for Groundwater Flow and Radionuclide Transport Modeling, San Francisco, September 1987.

Clemo, T. M. and Miller, J. D., "Simulation of Flow and Dispersion in the East Mesa Reservoir," EG&G Idaho SE-PB-84-056, 1984.

England, R. L., Kline, N. W., Ekblad, K. J. and Baca, R. G., "MAGNUM-2D Computer Code: User's Guide," Rockwell Hanford Operations RHO-BW-CR-143P, January 1985.

Freiburger, R. M., "Hydrothermal Injection Program East Mesa 1983-84 Test Data," EG&G Idaho SE-PB-84-044, September 1984.

Hull, L. C. and Clemo, T. M., "Dual Permeability Model: Laboratory and FRACSL Validation Studies," in Geothermal Injection Technology Program Annual Progress Report: FY-86, Idaho National Engineering Laboratory, EG&G-2511, Idaho Falls, Idaho, 1987a, pp. 21-39.

Hull, L. C. and Clemo, T. M., "Sensitivity Analysis of Dual-Permeability Systems," Proceedings: Twelfth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 1987b.

Hull, L. C. and Koslow, K. N., "Streamline Routing Through Fracture Junctions," Water Resources Research, V22, 12, November 1986, pp. 1731-1734.

Hull, L. C., Miller, J. D. and Clemo, T. M., "Laboratory and Simulation Studies of Solute Transport in Fracture Networks," Water Resources Research, V23, 8, August 1987, pp. 1505-1513.

Kline, N. W., England, R. L. and Baca, R. G., "CHAINT Computer Code: Users Guide," Rockwell Hanford Operations RHO-BW-CR-144P, December, 1985.

Large, R. M., "Hydrothermal Injection Program Phase 1 Test Data Index," EG&G Idaho REPB-83-015, July 1983.

Miller, J. D., "Simplified Prediction of Dixie Valley Injection Test," Confidential, in-press.

Miller, J. D. and Allman, D. W., "Dual Permeability Modeling of Flow in a Fractured Geothermal Reservoir," Proceedings: Eleventh Workshop on Geothermal Reservoir Engineering, Stanford University, SGP-TR-93, Stanford University, California, 1986, pp. 77-84.

Miller, J. D., Allman, D. S. and Wulf, D., "Raft River Fracture Characterization and Reservoir Simulation," Idaho National Engineering Laboratory SE-PB-84-058, 1984.

Miller, J. D. and Clemo, T. M., "Dual Permeability Modeling of Solute Transport in Discrete Fracture Systems," Proceedings: Thirteenth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford California, in press, 1988.

Miller, J. D., Clemo, T. M. and Hull, L. C., "FRACSL User's Manual," EG&G Idaho, ST-ES-06-87, November 1987.

Mitchell and Gauthier Associates, "Advanced Continuous Simulation Language (ACSL) User's Guide and Reference Manual," Mitchell and Gauthier Associates, Box 685, Concord, Massachusetts, 1986.

Pruess, K., "TOUGH User's Guide," Nuclear Regulatory Commission Report NUREG/CR-4645, June 1987.

DEVELOPMENT OF CHEMICAL TRACERS FOR RESERVOIR STUDIES

Michael C. Adams and Joseph N. Moore

University of Utah Research Institute, 391 Chipeta Way, Suite C,
Salt Lake City, UT 84108

ABSTRACT

Fluid tracers are necessary in order to define the movement of injected spent brine through a geothermal system. Because of high detection limits, the commonly used halide tracers are expensive or inaccurate to use with injection tests. At UURI we have tested 40 compounds for their use as geothermal tracers. Of these, 15 have been shown to be stable at temperatures of up to 250°C, and at least 4 are stable to 300°C. These tracers have detection limits of approximately 50 ppb, and we are currently working on lowering them to 60 ppt. We will be testing several of these tracers under actual geothermal conditions in a large-scale injection test at Dixie Valley this year.

INTRODUCTION

In most geothermal fields, the spent, cooled, brines must be injected back into the formation. The purposes of injection are to avoid surface and culinary water pollution and to maintain reservoir pressures. However, injection can lower the temperature of the produced fluids in a field by mixing with the hotter formation fluids. In order to mitigate this problem, the subsurface paths of the injected fluids must be known. Tracers can be used to label and track fluid movement and monitor chemical changes of the injected fluid.

Despite their potential importance to the geothermal operator, very few tracers are presently available and of those that are available, little is known about their stabilities or behaviors at the elevated temperatures that typify resources capable of electric power generation. Consequently, tracer development has been considered by industry representatives to be of prime importance. In response to this need, the University of Utah Research Institute initiated a program of development and testing of several organic anions for use as geothermal tracers.

During the past three years we have tested over 40 potential tracers in hydrothermal autoclaves at temperatures of up to 300°C. The molecular structures of these compounds are shown in Figure 1. These compounds are all various versions of an oxygen-containing solubilizing group on a benzene ring, with other distinctive substituents to identify the compound from the others. Of the 40 tested, 15 are stable at 250°C. These were the methylbenzoic acids, the benzenesulfonates, the benzene-dicarboxylates, and benzoic acid itself. The compounds that are the least stable at high temperatures are the fluorinated and trifluoromethylated benzoic and phenylacetic acids. Ironically, these are the best low-temperature groundwater tracers because of their non-biodegradable properties. Biodegradation is a problem for the tracers that we have developed, but only in the sample bottles. Thus, preservative must be used when the tagged fluids are sampled. We are currently performing experiments to determine what preservatives are best. In our experiments we use sodium azide, but formaldehyde may be feasible. Formaldehyde would be preferable because sodium azide must be used with care because of its reactivity.

Some of the tracers that we have developed are inexpensive enough to use in large-scale injection tests. These are the benzenesulfonic acids and benzoic acid. They are defined as inexpensive on the basis of current detection limits. However, this year we are developing enrichment techniques that will reduce the detection limits of many of the tracers by a factor of 100 to 1000. This will allow detection at concentrations as low as parts per trillion (ppt). Thus, tracers that are now too expensive to use in large-scale injection tests will be affordable once the detection limits are lowered.

This year we have also defined the kinetics of decay of fluorescein. Rate data have been obtained on fluorescein decay at 270° and 290°C in distilled and geothermal water. These data have been used to predict the rate of decay of fluorescein at lower temperatures. The predicted half-life of fluorescein at 200°C is 2 years, and at 250°C is 20 days. Although fluorescein is less stable than the other tracers that we have developed, it has the advantage of

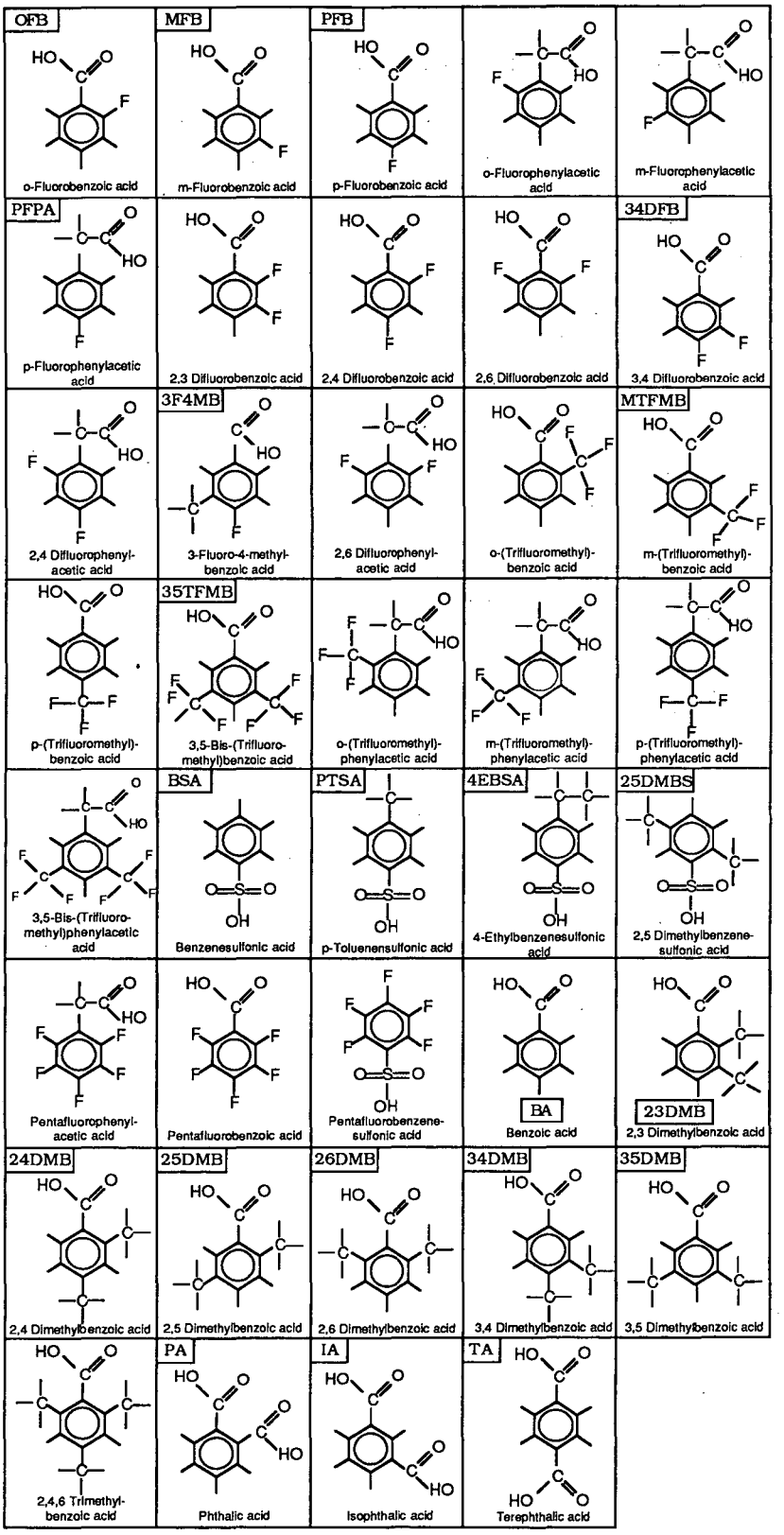


Figure 1. Structural formula of compounds tested as potential tracers

providing visible evidence of breakthrough, and is an aid to deciding on sampling frequency during a test. If our decay kinetics prove valid in field experiments, fluorescein can still be used to quantify breakthrough.

Tracers can be used for purposes other than quantifying injection breakthrough. For example, this year we used fluorescein and benzenesulfonate to quantify the behavior of a scale inhibitor slug injected into the Pleasant Bayou geopressured well. The injection consisted of three parts. The first fluid injected was sodium chloride, to clear the rock pathways of dissolved calcium, which would prematurely precipitate the scale inhibitor. This preflush was tagged with benzenesulfonate. The second part of the injection was the scale inhibitor itself, which was tagged with fluorescein. The final portion of the injection was a postflush, designed to push the scale inhibitor into the formation. The contrast between the sodium chloride postflush and the natural composition of the formation fluid was used to tag this portion of the test. Although the analyses are not yet complete, an early indication of success was the fact that the fluorescein provided a clear indication of the position of the slug when the well was backflowed, allowing for accurate sampling of the flow.

A strong emphasis of our program in the future will be the field testing of these tracers. Because we have done the majority of work that can feasibly be performed in the laboratory, we need to test our tracers in actual geothermal environments. The most cost-effective way of doing this is to combine our experiments with tests performed by industry. In September of 1988 we will perform such a test in cooperation with Oxbow Geothermal at the Dixie Valley field. Several tracers will be used to tag most of the injection wells, and all of the producing wells will be monitored. We expect this test to significantly improve the reservoir model of the Dixie Valley geothermal system.

ACKNOWLEDGEMENTS

Funding for these studies was provided by the U. S. Department of Energy under contract number DE-AC07-851D12489. The experiments were performed by Laszlo Fabry, Jong Ahn, and Jon Davis.

OPTIMIZATION OF INJECTION SCHEDULING IN GEOTHERMAL FIELDS

James Lovekin and Roland N. Horne

Stanford Geothermal Program

Abstract

This study discusses the application of algorithms developed in Operations Research to the optimization of brine reinjection in geothermal fields. The injection optimization problem is broken into two sub-problems: (1) choosing a configuration of injectors from an existing set of wells, and (2) allocating a total specified injection rate among chosen injectors. The allocation problem is solved first. The reservoir is idealized as a network of channels or arcs directly connecting each pair of wells in the field. Each arc in the network is considered to have some potential for thermal breakthrough. This potential is quantified by an arc-specific breakthrough index, b_{ij}, based on user-specified parameters from tracer tests, field geometry, and operating considerations. The sum of b_{ij}-values for all arcs is defined as the fieldwide breakthrough index, B. Injection is optimized by choosing injection wells and rates so as to minimize B subject to constraints on the number of injectors and the total amount of fluid to be produced and reinjected. The use of the various methods is demonstrated with reference both to hypothetical data and an actual data set from the Wairakei Geothermal Field in New Zealand.

1. INTRODUCTION

As the geothermal industry matures, the need for a method to optimize a program of reinjection becomes more important. Fluid injection holds the promise of increased recoveries from geothermal fields by providing a medium to absorb a greater percentage of the heat in the reservoir rock. Unfortunately, injection into geothermal fields also has potential for decreasing thermal recovery by extracting heat unevenly. If the injected fluid travels too directly to producing wells without contacting a large volume of the reservoir rock, premature thermal breakthough may occur and the economic life of the field may be cut short. This is all the more likely because flow patterns in geothermal reservoirs are often controlled by fractures. Tracer surveys provide a powerful tool for gaining insight into these flow patterns. It is not uncommon for more distant wells to show stronger tracer response than wells which are closer to the injector.

The purpose of this study is to provide a systematic approach for using such tracer data, together with information about field geometry and operating conditions, in the optimization of injection scheduling in geothermal fields.

The operator of a geothermal field is interested in two questions:

(1) Which wells should be made injectors?

(2) How should the total required injection rate be distributed?

The first question may be called the problem of *configuration*, and the second the problem of *allocation*. In practise, the operator typically solves the configuration problem first. Often, operational considerations dictate the solution. It turns out, however, that the solution to the allocation problem provides a straightforward approach to solving the configuration problem for an unrestricted case. For this reason, this study will address the allocation problem first.

The inspiration for this study's approach to the allocation problem grows directly out of the observation that, because of fracturing in geothermal fields, tracer response between two wells is often unrelated to how close the wells are to each other. In this approach, the geothermal reservoir is idealized as a network of direct connections or arcs between every pair of wells. Each arc is presumed to have some potential for thermal breakthrough. This potential is assigned a numerical value called a breakthrough index, b_{ij}, which is some function of operating rates for the wells on either end of the arc and an arc cost, c_{ij}, based on tracer test parameters and field geometry. The sum of b_{ij}-values for all arcs is defined as the fieldwide breakthrough index, B. Injection is optimized by choosing injection rates so as to minimize B, subject to constraints on individual well capacities and total injection requirements. The allocation problem bears a striking resemblance to problems of linear programming (LP) which are studied in the field of Operations Research. The thesis of this paper is that algorithms from Operations Research, used in conjunction with tracer tests, provide a useful method of optimizing geothermal injection.

2. BACKGROUND

The bulk of field experience indicates that rapid thermal breakthrough and large tracer recoveries correlate strongly.[1,2,3] Tracer test results have been published for a number of fields, including the Wairakei and Broadlands Fields in New Zealand,[4] the Geysers Field in California,[5] the Larderello Field in Italy,[6] the Kakkonda, Onuma, Hatchobaru, and Otake Fields in Japan,[7] and the Klamath Falls Field in Oregon.[8]

In treating a geothermal field as a network of direct connections, the current study builds on Horne's idea of a connectability map. The reservoir is considered as a network of pipes, each with some physical parameter (analagous to a diameter or a Reynold's number) expressing the ease with which a tracer slug or a thermal front could pass through. To gain insight into the optimization of such a system, the literature of optimizing pipe networks was reviewed. Linear programming (LP) was found to be a commonly employed technique.[9,10,11,12,13,14] In these studies of pipe network optimization, the objective function to be minimized was typically some combination of installment costs and discounted operating costs, while the system constraints were provided by linearized flow equations, network geometry, water supply limitations, and outlet flow requirements. The decision variables in these formulations were usually the dimensions (lengths, diameters, or both) of the pipes to be installed.

The current study's approach to optimizing geothermal injection draws an analogy to the transportation problem. As will be discussed in greater detail later, the cost associated with each arc is based in part on parameters from tracer tests. Several authors have discussed methods of inferring fracture apertures and other reservoir properties from tracer tests by

References are at end of the text.

applying a non-linear, least-squares method of curve-fitting to plots of produced tracer concentration versus time.[16,17,18] The method proposed here allows the use of any reservoir properties so inferred. However, since it builds on the assumption (supported by field experience) that tracer response and thermal response are strongly correlated, it does not require a solution of the inverse problem. Rather than make inferences about what the geothermal reservoir actually is, the proposed method makes operational decisions directly based on what the reservoir actually does.

3. ALLOCATION PROBLEM

3.1 Analogy to Transportation Problem

Figure 1 illustrates the analogy between the classis "transportation problem" and the injection optimization problem. In this analogy, nodes 1 and 2 could represent injection wells, and nodes 3, 4, and 5 could represent production wells. The arcs in the network represent the potential fluid flow paths from each injector to each producer. However, these arcs do not imply anything about the actual geometry of fluid flow. Each arc has associated with it some "cost" per unit of fluid transmitted, where the cost is an expression of the increased likelihood of thermal breakthrough, as assessed based on tracer tests, field geometry, and operational considerations. The problem is to minimize the likelihood of thermal breakthrough throughout the field, while meeting constraints on the injection capacity of individual wells and satisfying total injection requirements.

The following LP formulation for the injection optimization problem illustrates the parallels with the transportation problem for the case of N_1 injectors and N_2 producers:

$$\text{Minimize} \quad B = \sum_{i=1}^{N_1}\sum_{j=1}^{N_2} b_{ij} = \sum_{i=1}^{N_1}\sum_{j=1}^{N_2} c_{ij}\, q_{ri}$$

$$\text{Subject to} \quad q_{ri} \le q_{rimax}, \qquad i = 1, N_1$$

$$\sum_{i=1}^{N_1} q_{ri} = Q_{rtot}$$

$$q_{ri} \ge 0, \qquad i = 1, N_i$$

The decision variables, q_{ri}, are the reinjection rates for each injection well, i. The arc costs, c_{ij}, express the increased chance of thermal breakthrough resulting from movement of a unit of fluid from each injector to each producer. The product of an injection rate and an arc cost constitutes the breakthrough index, b_{ij}, for a particular arc. The summation of breakthrough indices for all arcs constitutes the fieldwide breakthrough index, B, which is the objective function to be minimized. The supply constraints for the injection optimization problem simply express the requirement that each injector has to operate at a rate less than its capacity, q_{rimax}. The demand constraint requires that the summation of all injection rates must equal the specified fieldwide total injection rate, Q_{rtot}. Finally, the non-negativity constraint ensures that none of the injectors are operating at "negative rates", *i.e.*, that they are not acting as producers.

3.2 Definition of Arc Costs

In the injection optimization problem, the arc costs are expressed in terms of increased likelihood of premature thermal breakthrough. The relation between known reservoir parameters and thermal breakthrough is difficult to quantify. For instance, it would be difficult to calculate the time required for a given percentage drop in the enthalpy of produced fluids without detailed knowledge of reservoir properties and operating conditions. For the purposes of optimization, however, such detailed knowledge

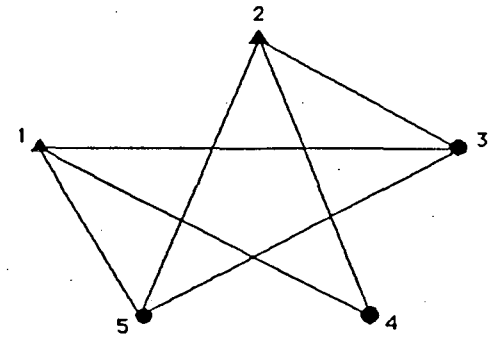


Figure 1
Idealized network of arcs.

is not necessary. All that is required is a *relative* assessment of the "cost" of injection into different wells. For the optimization process to be valid, it is only necessary that the likelihood of thermal breakthrough be assessed on the same terms for each injector/producer pair. On this basis, one can consider any known parameter that relates injectors and producers and decide, in relative terms, whether it has a direct or an inverse relationship with the likelihood of thermal breakthrough. This allows one to weight one's definition of arc costs according to whatever data are available or whatever factors one considers important.

In the computer algorithms prepared for this study, the weighting factors composing the arc costs have been drawn from three sources: tracer tests, field geometry, and operating conditions. Table 1 describes the various weighting factors used. Each of these factors will be discussed in the following paragraphs.

The tracer test parameters considered in this study are based on a slug-type tracer test. In this type of test, a certain quantity or "slug" of tracer is released instantaneously in an injection well. This gives rise to a characteristically spiked tracer response profile at the production wells, as illustrated in Figure 2. One parameter which may be directly interpreted from such a profile is the initial tracer response time, t_i. Intuitively, t_i should be inversely correlated with the likelihood of thermal breakthrough. That is, the longer it takes for the tracer to break through from a given injector to a given producer, the less likely it is that premature thermal breakthrough will be a problem between those two wells. Therefore, t_i enters into the calculation of arc costs as a reciprocal, as shown in Table 1.

Table 1
Weighting factors for arc costs

Factor	Definition	Relation to Arc Cost		
t_i	Initial tracer arrival time	c	α	$1/t_i$
t_p	Peak tracer arrival time	c	α	$1/t_i$
C_p	Peak tracer concentration	c	α	C_p
$\int$	Fractional tracer recovery	c	α	$\int$
q_{pt}	Producing rate during tracer test	c	α	$1/q_{pt}$
q_{rt}	Injection rate during tracer test	c	α	$1/q_{rt}$
q_p	Producing rate under operating conditions	c	α	q_p
L	Horizontal distance between wells	c	α	L^2
H	Elevation change from producing zone	c	α	e^{SH}

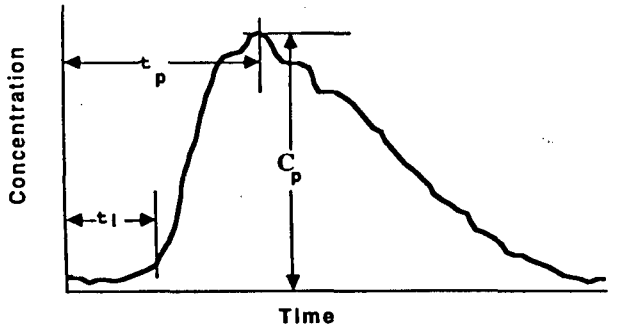


Figure 2.
Schematic response from slug-type tracer test.

Two other weighting factors which are available from a tracer response profile are the peak tracer concentration, C_p, and the fractional tracer recovery, f. C_p is simply the concentration at time t_p. To obtain a value for f, one must first calculate the mass of tracer recovered by integrating the area under the tracer response curve and multiplying by the producing rate (assumed constant) during the tracer test. (If the producing rate was not constant during the tracer test, one may multiply each concentration measurement by its respective producing rate to produce a curve of the amount of tracer recovered per unit time, and then calculate the total tracer recovered by integrating under this curve.) The f-value is then just the mass of tracer produced divided by the mass of tracer injected. Both C_p and f are positively correlated with the likelihood of premature thermal breakthrough, and they may therefore be used directly as weighting factors in calculating arc costs.

In the category of weighting factors from field geometry, the most accessible parameter is the horizontal distance between wells (L). It is important to recognize that L has no predictable relation with thermal breakthrough in the case of fractured reservoirs. However, in the case of porous-media-type reservoirs or reservoirs in which high permeability zones approximate horizontal planes (*e.g.*, at contacts between lava flows), the flow of injected fluid away from injection wells in the reservoir may be radial. In this case, the surface area available for heat exchange from the rock to the cooler fluid grows in proportion to the square of L.[19] Therefore, the likelihood of thermal breakthrough may be considered inversely proportional to L^2, which may enter into the calculation of arc costs as a reciprocal. It should be emphasized, though, that distance between wells is not a reliable substitute for tracer test data in the common case of fractured geothermal fields.

The other accessible parameter in terms of field geometry is the difference in elevation (H) between producing and injecting zones. Tracer test data from Wairakei suggest that tracer breakthrough is much more likely in deep producing wells.[4] This makes physical sense, because cooler injected fluids are more dense than reservoir fluids and would be expected to sink within the reservoir. However, H itself is not appropriate as a weighting factor, because it may be either positive or negative. To calculate a weighting factor based on H, this study has used an exponential function, because it is strictly positive and because it increases or decreases the arc cost based on whether H is positive (producing zones below injecting zones) or negative (producing zones above injecting zones). When H is zero (producing and injecting zones at the same elevation), the exponential of H is 1, and the arc cost is unaffected. To keep the exponential term from dominating all other weighting factors, the exponent, H, has been multiplied by a scaling factor, S. Thus, elevation enters into the calculation of arc costs as the weighting factor e^{SH}. For elevation differences on the order of hundreds of meters, an S-value of 10^{-3} keeps this weighting factor in a range between 0.37 and 2.72.

The following equation illustrates how the various weighting factors discussed so far could be combined in calculating the breakthrough index for each arc:

$$b = c\,q = \left[\frac{1}{t_i}\,\frac{1}{t_p}\,C_p f L^2\, e^{SH}\,\frac{q_p}{q_{pt}}\,\frac{1}{q_{rt}}\right] q_r$$

The expression in parentheses represents one formulation of the arc cost in expanded form. Because the different weighting factors apply in different situations, an actual optimization run would probably use only some subset of these factors. For example, t_i and t_p would usually not both be used. It should also be noted that the list of weighting factors is not exhaustive: other weighting factors could be included, based on the developer's knowledge of the reservoir and operating requirements. Further, although this study has applied a scaling factor only in the case of elevation differences, scaling factors could easily be applied to other arc cost components as well, depending on which factors the developer considers important.

3.3 Computer Program Descriptions

Four separate algorithms were formulated in this work, as summarized in Table 2. These methods are described in detail in reference 23, which also contains program listings.

A general summary of the similarities and differences between the programs is provided in Table 3. As the table shows, all the LP programs operate by providing an explicit

Table 2
Summary of computer programs to optimize injection

Program Name	Application	Data Entry Program
LPAL1	Linear programming allocation for injection rates only	LPIN1
LPAL2	Simultaneous linear programming allocation for both injection and production rates	LPIN2
LPAL3	Alternating linear programming allocation for both injection and production rates	LPIN3
QPAL	Quadratic programming allocation for both injection and production rates	QPIN
INCON	Injector configuration chooser	CONDAT

Table 3
Comparison of allocation programs

Program Feature	LPAL1	LPAL2	LPAL3	QPAL
Provides ranking of injectors	Yes	Yes	Yes	No
Solves for both injection and production rates	No	Yes	Yes	Yes
Allows wells to be shut in	Yes	No	Yes	Yes
Well ranking varies with total rates	No	No	Yes	NA
Assesses quality of solution	No	No	No	yes

ranking of wells based on cost coefficients and throttling back one well at a time, from most to least damaging, until total rate requirements are just met. QPAL does not provide an explicit ranking of wells, but it uses a quadratic programming solver which generally yields the same rate allocations as LPAL3. All the programs except LPAL1 allocate both injection and production rates. All the programs except LPAL2 allow wells to be shut in, *i.e.*, to be assigned a zero rate. The well rankings provided by LPAL1 and LPAL2 do not vary with changes in total operating rates, because the arc costs used in calculating cost coefficients are all fixed. Effectively, this means that neither LPAL1 nor LPAL2 can take into account the mutual dependence of injection and production rates in determining the likelihood of thermal breakthrough. For this reason, LPAL3 is the most realistic of the LP programs presented. (Note that if producing well rates are predetermined, LPAL3 can be used to generate the same injection allocation as LPAL1 by simply setting the required total producing rate equal to the sum of the known well rates.) QPAL also accounts for the mutual dependence of injection and production rates and is the only program presented which explicitly assesses the quality of the solution by identifying indeterminate cases.

4. CONFIGURATION PROBLEM

4.1 Enumeration Approach

The computer programs discussed so far have addressed the problem of how to allocate a specified total injection rate among a pre-chosen set of injection wells. The configuration problem concerns how to choose this set of injectors from a group of pre-existing wells. The solution of the allocation problem provides a straightforward approach to the configuration problem. The end result of the allocation routines is not only a set of injection rates but a minimized value of the fieldwide breakthrough index, B. For a particular configuration, this value expresses in a single number the likelihood of premature thermal breakthrough for the entire field under optimal loading. Therefore, the configuration problem may be approached by enumeration, *i.e.*, by applying an allocation algorithm to each possible injector configuration and selecting the configuration with the lowest minimized B-value as optimal.

The theoretical upper limit on the number of configurations which an enumerative approach would have to consider is given by the expression

$$\frac{N!}{N_1!\,N_2!}$$

where N = total number of wells
N_1 = number of injectors
N_2 = number of producers

For the number of wells in a typical geothermal field, this value is small enough that consideration of all configurations would not require excessive computer time. Moreover, certain configurations could usually be removed from consideration because the sum of maximum rates for the wells involved would be insufficient to meet the total rates required. Thus, the actual number of configurations for which the allocation routine would need to be run would usually be less than the theoretical maximum.

It should be noted that the data requirements for such a configuration-choosing routine are much more extensive than for the allocation routines previously discussed. The data must characterize not just the arcs between designated injector/producer pairs (as in Figure 1) but between *all* well pairs. For directional information, data should be supplied in both directions. A complete set of tracer data, for example, requires that a separate tracer test be conducted on each well and that tracer response be monitored in all other wells. Further, rate limitations must be specified for each well both as an injector and as a producer.

4.2 Computer Program Description

This study has developed a configuration-choosing program called INCON, which uses the enumerative approach in conjunction with the QP allocation algorithm. The computer codes for INCON and its associated data-entry program (CONDAT) are described in reference 23 The input parameters for INCON include the total number of wells, the maximum allowable number of injectors, and the required fieldwide production and injection rates. For each possible injector configuration, the program checks to insure that the required fieldwide rates can be met. It then runs the QP allocation algorithm on each feasible configuration, and selects the configuration with the lowest B-value. A flow chart for INCON is presented in Figure 3.

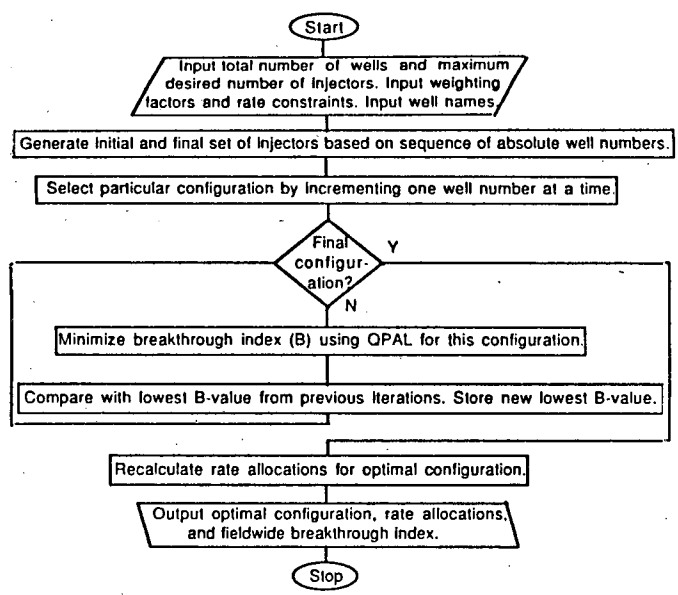


Figure 3
Flow chart for INCON.

5. APPLICATIONS TO WAIRAKEI

5.1 Background

The Wairakei Geothermal Field is a liquid-dominated field located near the town of Taupo on the North Island of New Zealand. A series of tracer tests were conducted in the field in 1979 and 1980. These tests took advantage of a downflow of cooler fluid in several wells from a zone above the reservoir. The tests were intended to determine where this cooler fluid was going and whether production from offsetting wells was being adversely affected. Glass vials of radioactive tracer (Iodine-131) were lowered into the downflowing wells and broken below the point of cool fluid entry. Producing wells were monitored continuously for tracer response. Measured tracer concentrations were normalized by dividing them by the amount of tracer injected to account for variation in the size of the tracer slugs in the different tests. McCabe *et al.* provide a detailed description of the testing procedures and results.[4]

The Wairakei tracer tests are a classic example of fracture-controlled flow in a geothermal reservoir. In several instances, wells which were further away from the tracer injection wells exhibited stronger response than closer wells. Because the Wairakei Field illustrates so well the notion of a geothermal reservoir as a network of direct connections between wells, and because it has several sets of tracer data to quantify these connections, it is an ideal test case to demonstrate the use of the injection optimization programs presented in this study.

Reference 23 summarizes the Wairakei data that have been used for the allocation programs. The tracer test parameters (t_i, t_p, C_p, and f) used were those reported by McCabe *et al.*[4] Production rates during the test (q_{pt}) were estimated from actual production rates as of December, 1976, as reported by Pritchett *et al.*[20] Injection rates during the tests (q_{rt}) for Wells WK-101 and WK-107 are those reported by Bixley.[21] Since no q_{rt}-value was available for Well WK-80, a value of 50 kg/s was estimated. These values of q_{pt} and q_{rt} were also used as the maximum well capacities (q_{rmax} and q_{pmax}). Values of the horizontal distance (L) between wells were determined from well maps, since the wells were all drilled vertically. To calculate values of the elevation change (H) between producing and injecting zones, the following assumptions were made: (1) The depth of the injection zone was taken as the depth at which the tracer was released. (2) The depth of the production zone was taken as the depth of the lowest fissure indicated on drill logs,[22] or, in the absence of reported fissures or logs, as the midpoint of the open interval.[20] (3) For Well WK-121, the elevation of the uphole perforations at 975 m (-532 m sub-sea) was used, since this was reported to be the primary source of production.[4]

For the configuration-choosing program, the maximum well capacities were assumed to apply for all wells both as injectors and as producers. A computer program (HGEN) was written to generate a set of elevation changes for a complete set of arcs using the injection and production zone elevations just described. A second computer program (LGEN) was written to calculate a complete set of horizontal distances from the surface well coordinates reported by Pritchett.[20] These calculated L-values differed only slightly from the measured L-values used with the allocation programs.

5.2 Optimal Rate Allocations

5.2.1 Sensitivity to Total Rate

All four allocation programs were run on the Wairakei data to investigate how varying total injection and production rates would affect the optimal rate allocation. The wells involved in the tracer tests included the three wells with cool fluid downflow (the "injection" wells) and nineteen producing wells. The field-wide capacities for injection and production were 140 and 689 kg/s, respectively, based on the sum of individual well capacities. Sensitivity studies were run using a single weighting factor ($1/t_i$) to calculate cost coefficients. These sensitivity studies entailed fixing one of the total rates (either Q_{rtot} or Q_{ptot}) at a value below total capacity and varying the other from total capacity to a low rate.

For all the sensitivity studies, LPAL1 and LPAL2 established well rankings which were invariate with total rates. This was as expected for these two programs, because neither of them incorporates variable well rates into their calculations of cost coefficients. LPAL1 ranked WK-107 as the most prone to thermal breakthrough, followed by WK-101 and WK-80. LPAL2 ranked the injectors the same way and also provided a ranking of the producers. As total rates were cut back in the sensitivity studies, these programs throttled back one well at a time in the order of the predetermined rankings. In contrast, the ranking of wells by LPAL3 varied with total rates, and the rate allocations for one category of wells (producers or injectors) depended on the rates of wells in the other category. Further, the rate allocations from QPAL generally agreed with those from LPAL3, as expected. These points are illustrated by the following three sensitivity studies.

In the first sensitivity study, Q_{ptot} was fixed at 550 kg/s, and Q_{rtot} was varied from a capacity rate of 140 kg/s to 50 kg/s. Table 4 shows the sequence in which LPAL3 and QPAL shut wells in. (This table and all subsequent tables of sensitivity data present ranking for all three injectors; however, for the sake of brevity, the only producers listed are those with curtailed rates.) Several points are worth noting from Table 4. First, the cost coefficients of the producers shift continuously as the injection rate drops. Second, for marginal changes in the injection rate, the relative ranking of the producers stays the same. For example, as Q_{rtot} goes from 140 to 100 kg/s, the producers maintain their relative ranking and their allocated rates. As long as the producing rate allocations remain unchanged, the cost coefficients for the injectors also stay the same. However, when Q_{rtot} drops to the point that WK-107 is shut in entirely (90 kg/s), the ranking of the producers shifts, which changes their allocated rates and alters the cost coefficients of the injectors. Table 4 also illustrates that the allocations by LPAL3 and QPAL generally agree. This agreement breaks down when Q_{rtot} is reduced to 50 kg/s, because the ranking of producers becomes indeterminate. LPAL3 chooses to curtail WK-121, but this choice is arbitrary because all remaining producers have the same cost coefficient (0.005). QPAL curtails a different set of producers, but labels

Table 4

Sensitivity of Wairakei well ranking to total rate.
Case 1. Q_{ptot} = 550 kg/s; Q_{rtot} varies

	LPAL3				QPAL	
Q_{rtot} kg/s	Injectors	Cost Coefficient	Curtailed Producers	Cost Coefficient	Injectors	Curtailed Producers
140	107	81	24a	250	107	24a
	101	20	48a	167	101	48a
	80	13	121a	33	80	121a
			116a	31		116a
			76b	29		76b
100	107b	81	24a	50	107b	24a
	101	20	48a	33.3	101	48a
	80	13	121a	33.3	80	121a
			116a	31.2		116a
			76b	28.5		76b
90	107a	312	121a	33	107a	121a
	80	8	116a	31	80	116a
	101	0.055	76a	29	101	76a
			103a	20		103a
			108b	9		108b
70	107a	312	121a	33	107a	121a
	80b	8	116a	25	80b	116a
	101	0.055	76a	24	101	76b
			103a	20		103a
			108b	5		108b
50	107a	308	116a	15	80a	18a,d
	101a	16	76a	13	101a	22a,d
	80	550	108a	9		24a,d
			121b,c	0.005		30a,d
						121a,d
						116b,d

a Total curtailment
b Partial curtailment
c Arbitrary allocation by LPAL3
d Non-unique allocation by QPAL3

the solution as non-unique. It should be noted, however, that even with a sparse data set, the problem of indeterminacy does not occur until only one injector remains active. This illustrates that LPAL3 and QPAL make use of all available data first in deciding which wells to cut back.

The second sensitivity study fixed Q_{rtot} at 100 kg/s and decreased Q_{ptot} from a capacity rate of 689 kg/s to 400 kg/s. In this case, the cost coefficients for the injectors shift continuously as Q_{ptot} is reduced. However, because WK-107 is ranked as the most damaging injector at all levels of Q_{ptot}, the injection rate allocation stays the same, and the cost coefficients for the producers stay the same as well. As Q_{ptot} is reduced, the producers are throttled back one at a time, according to rank. The allocations by QPAL agree with those by LPAL3, as before. At a Q_{ptot} of 400 kg/s, an indeterminate condition is reached when LPAL3 elects arbitrarily to curtail WK-68, which has the same cost coefficient as WK-70. QPAL makes the same allocation, but labels it as non-unique.

In the third sensitivity study, Q_{rtot} was fixed at a lower rate of 70 kg/s, and Q_{ptot} was again reduced gradually from an initial rate of 689 kg/s. The ranking of producers differed from that of the previous sensitivity study because the injection allocation has changed (*i.e.*, WK-107 has been shut in). As additional producing wells are shut in, the ranking of the injectors shifts so that WK-80 rather than WK-101 is curtailed. This causes a corresponding realignment of the producing wells. At a Q_{ptot} of 500 kg/s, the problem becomes doubly indeterminate, first because the two remaining injectors have the same cost coefficient (0.05), and second because all the producers after WK-108 also have identical cost coefficients (0.007). For this indeterminate case, LPAL3 and QPAL make different allocations in both the injector and the producer categories.

In summary, the three sensitivity cases showed that LPAL3 and QPAL could optimize injection for a fixed injector configuration in a way that accounted for the interdependence of injection and production rates. The rate allocations provided by LPAL1 and LPAL2 were less satisfying because they were based on a fixed well ranking. The ranking provided by LPAL3 depended on total rates, though for marginal changes in total rates the relative ranking remained the same. The rate allocations of LPAL3 and QPAL agreed in all cases except when the optimal allocation was indeterminate.

5.2.2 Sensitivity to Different Weighting Factors

A sequence of runs applying a variety of different weighting factors to Wairakei data showed that tracer test parameters tended to yield similar rate allocations, whether used singly or in combinations. Further, elevation changes alone could be used to calculate allocations which were similar to those from tracer test parameters. On the other hand, using just the horizontal distance between wells yielded totally different rate allocations. This suggests that, for fractured reservoirs such as Wairakei, elevation changes are much more important than horizontal distances in determining optimal injection allocations.

5.3 Optimal Configuration

To demonstrate the application of the configuration-choosing program (INCON) to the Wairakei Field, two runs were made, the first based on elevation changes between producing and injecting zones (*H*-based), the second based on horizontal distances between wells (*L*-based). These two data sets were selected because, despite all the tracer data available for Wairakei, *H* and *L* were the only parameters that could provide a characterization for each arc. The runs assumed that Q_{ptot} and Q_{rtot} were to be 550 and 100 kg/s, respectively. The maximum number of injectors was specified as three. With a total of 22 wells, this meant that the maximum number of configurations to be considered was 1,540. However, because not all the combinations of wells could achieve the required total rates, the number of combinations for which INCON actually performed a rate allocation was only 1,122. Each execution of the program with these data sets required about 50 minutes of real time using a DEC VAX 11/750 computer.

As would be expected, the two configurations are quite different. The *H*-based configuration (see Table 5) places injection in deep wells near the center of the field, while the *L*-based configuration places injection in isolated wells at the field's southeast corner. Based on the parallels between *H*-based and tracer-based rate allocations discussed in the previous section, it might be reasonable to expect that the *H*-based injector configuration would be better in practise. However, it should be noted that the final *H*-based configuration depends not just on elevations but on rate constraints. If INCON had optimized on the basis of elevation alone, it would have simply chosen the three deepest wells (WK-48, WK-121, and WK-18) as injectors. Because these wells could not collectively produce 100 kg/s, the program designated WK-121 and WK-18 as inactive producers

Table 5

Rate allocation for optimal well configuration in Wairakei, based on elevation differences between wells. Q_{rtot} = 100 kg/s; Q_{ptot} = 550 kg/s

Injector Name	Maximum Injection Rate	Assigned Injection Rate
WK-24	33	33
WK-48	20	20
WK-55	47	47
Producer Name	**Maximum Producing Rate**	**Assigned Producing Rate**
WK-18	11	0
WK-22	13	13
WK-30	44	44
WK-44	34	0
WK-67	50	40
WK-68	10	10
WK-70	40	40
WK-74	49	49
WK-76	45	45
WK-80	50	50
WK-80	52	0
WK-83	52	52
WK-88	53	0
WK-101	40	40
WK-103	28	28
WK-107	50	50
WK-108	51	51
WK-116	38	38
WK-121	19	0

and chose the next two deepest wells (WK-24 and WK-55) as injectors instead. The combined maximum rates of these three injectors happened to be exactly 100 kg/s. It is clear, though, that slight changes in either the estimated capacities for individual wells or the required total rate could cause the optimal *H*-based configuration to change significantly.

6. CONCLUSIONS

6.1 The optimization of injection scheduling in geothermal fields may be accomplished by working in relative terms with data directly available from tracer tests, field geometry, and operating considerations.

6.2 Linear and quadratic programming may be used to allocate a specified total injection rate among pre-chosen wells. Such methods should allow for the interdependence of injection and production rates in determining the likelihood of thermal breakthrough.

6.3 The optimization techniques described in this study make use of all available data first in deciding which wells to eliminate as injectors. The techniques are not a substitute for efforts to understand reservoir behavior in a more physical sense, but they allow a geothermal developer to make beneficial use of whatever tracer return data are available.

6.4 For the Wairakei Geothermal Field, several different combinations of tracer test data yield the same allocations of injection and production rates. This suggests that the design of an optimal injection strategy does not depend critically on fine details of tracer response.

6.5 For fractured reservoirs such as Wairakei, elevation differences between production and injection zones are much more important than horizontal distances between wells in determining the optimal allocation of injection rates. The fact that large elevation differences tend to correlate with strong tracer response supports the theory that reinjected water moves rapidly downward within the reservoir.

6.6 The choice of an optimal injector configuration may be made by enumerating all feasible configurations, optimizing the rate allocation for each, and selecting the configuration with the lowest potential for premature thermal breakthrough. However, the solutions provided by such an approach are very dependent on specified rate constraints.

Acknowledgement

Stanford University has been generous in its financial support by making funds available to this study from several sources, including the Orcutt and Rhoades Funds and a fellowship from the Chevron Corporation. This work has also been supported as part of the Stanford Geothermal Program under contracts No. DE-AS03-80SF-11459 and No. DE-AS07-84ID-12529 from the U. S. Department of Energy.

REFERENCES

1. Nakamura, H., "Development and Utilization of Geothermal Energy in Japan," in *Transactions*, vol. 5, pp. 33-35, Geothermal Resources Council, Davis, CA, Oct., 1981.
2. Horne, R. N., "Effects of Water Injection into Fractured Geothermal Reservoirs: a Summary of Experience Worldwide," Report No. SGP-TR-57, Stanford Geothermal Program, Stanford, CA, June, 1982.
3. Horne, R. N., "Reservoir Engineering Aspects of Reinjection," *Geothermics*, vol. 14, no. 2/3, pp. 449-457, 1985.
4. McCabe, W. J. *et al.*, "Radioactive Tracers in Geothermal Underground Water Flow Studies," *Geothermics*, vol. 12, no. 2/3, pp. 83-110, 1983.
5. Gulati, M. S. *et al.*, "Tritium Tracer Survey at the Geysers," in *Transactions*, vol. 2, pp. 237-239, Geothermal Resources Council, Davis, CA, July, 1978.
6. Giovannoni, A. *et al.*, "First Results of a Reinjection Experiment at Larderello," in *Proceedings*, Seventh Workshop on Geothermal Reservoir Engineering, pp. 77-83, Stanford Geothermal Program, Stanford, CA, December, 1981.
7. Horne, R. N., "Geothermal Reinjection Experience in Japan," *J. Pet. Tech.*, pp. 495-503, March, 1982.
8. Johnson, S. E., "Tracer Test Analysis of the Klamath Falls Geothermal Resource: a Comparison of Models," Report No. SGP-TR-81, Stanford Geothermal Program, Stanford, CA, June, 1984.
9. Alperovits, E. and Shamir, U., "Design of Optimal Water Distribution Systems," *Water Resources Research*, vol. 13, no. 6, pp. 885-900, Dec., 1977.
10. Quindry, G. E. *et al.*, "Optimization of Looped Water Distribution Systems," *Journal of the Environmental Engineering Division*, vol. 107, no. EE4, pp. 665-679, ASCE, August, 1981.
11. Oron, G. and Karmeli, D., "Solid Set Irrigation System Design Using Linear Programming," *Water Resources Bulletin*, vol. 17, no. 4, pp. 565-570, American Water Resources Association, August, 1981.
12. Bhave, P. R. , "Optimization of Gravity-Fed Water Distribution Systems: Theory," *Journal of Environmental Engineering*, vol. 109, no. 1, pp. 189-205, ASCE, February, 1983.
13. Bhave, P. R. , "Optimization of Gravity-Fed Water Distribution Systems: Applications," *Journal of Environmental Engineering*, vol. 109, no. 2, pp. 383-395, ASCE, April, 1983.
14. Morgan, D. R. and Goultier, I. C., "Optimal Urban Water Distribution Design," *Water Resources Research*, vol. 21, no. 5, pp. 642-652, May, 1985.
15. Hillier, F. S. and Lieberman, G. J., *Introduction to Operations Research*, Fourth Edition, pp. 184-212, Holden-Day, Inc., Oakland, CA, 1986.
16. Fossum, M. P., "Tracer Analysis in a Fractured Geothermal Reservoir: Field Results from Wairakei, New Zealand," Report No. SGP-TR-56, Stanford Geothermal Program, Stanford, CA, June, 1982.
17. Jensen, C. L., "Matrix Diffusion and Its Effect on the Modeling of Tracer Returns from the Fractured Geothermal Reservoir at Wairakei, New Zealand," Report No. SGP-TR-71, Stanford Geothermal Program, Stanford, CA, December, 1983.
18. Walkup, G. W., Jr., "Characterization of Retention Processes and Their Effect on the Analysis of Tracer Tests in Fractured Reservoirs," Report No. SGP-TR-77, Stanford Geothermal Program, Stanford, CA, June, 1984.
19. Pruess, K. and Bodvarsson, G. S., "Thermal Effects of Reinjection in Geothermal Reservoirs With Major Vertical Fractures," *J. Pet. Tech.*, pp. 1567-1578, Sept., 1984.

20. Pritchett, J. W., *et al.*, "Reservoir Engineering Data: Wairakei Geothermal Field, New Zealand," Report No. SS-R-78-3597-1, Systems, Science, and Software, La Jolla, CA, March, 1978.

21. Bixley, P. F., "Cooling of the Wairakei Reservoir During Production," in *Proceedings*, Eleventh Workshop on Geothermal Reservoir Engineering, pp. 169-174, Stanford Geothermal Program, Report No. SGP-TR-93, Stanford, CA, January 21-23, 1986.

22. Grindley, G. W., "The Geology, Structure, and Exploitation of the Wairakei Geothermal Field, Taupo, New Zealand," N. Z. Geol. Surv. Bull. n.s. 75, Wellington, N. Z., 1965.

23. Lovekin, J., "Optimization of Injection Scheduling in Geothermal Fields ," Report No. SGP-TR, Stanford Geothermal Program, Stanford, CA, May, 1987 .

Simulation Tools for Geothermal Reservoir Engineering

Karsten Pruess

Earth Sciences Division, Lawrence Berkeley Laboratory
University of California, Berkeley, CA 94720

ABSTRACT

This article gives a brief review of the current status of geothermal reservoir simulation methodology and applications. Design and capabilities of Lawrence Berkeley Laboratory's multiphase fluid and heat flow simulators MULKOM and TOUGH are discussed. Significant applications to geothermal reservoir problems are highlighted. We conclude with some considerations on future directions in geothermal reservoir simulation technology.

INTRODUCTION

In the early-to-mid seventies, the U.S. Department of Energy and its predecessors initiated efforts to develop geothermal reservoir simulators, i.e., computer programs capable of simulating the behavior of geothermal reservoirs in their natural state as well as in response to exploitation. It was hoped that a computer simulation capability could help to improve our understanding of geothermal resources, and could thereby contribute to their more rapid and efficient utilization.

During the last decade, as a result of development efforts by National Laboratories, the U.S. Geological Survey, universities, and private companies, reservoir simulation has become a widely used tool for studying fluid and heat flow in geothermal systems. Furthermore, techniques developed in geothermal reservoir simulation are finding applications in other areas, such as in the geologic disposal of high-level nuclear wastes, and in thermally enhanced oil recovery. The first simulators capable of handling the difficult numerics of coupled fluid and heat flow, and multiphase flow with phase transitions, appeared in the mid-to-late 70s (for an early review see Pinder, 1979). An important milestone in the development and acceptance of geothermal reservoir simulators was reached in 1980 when a code comparison project demonstrated satisfactory agreement between several simulation programs for a number of multiphase fluid and heat flow problems (Stanford, 1980). Subsequently special techniques were developed for treating flow in fractured media (Pruess and Narasimhan, 1985; Clemo, 1985; Miller and Allman, 1986). Efforts were also made to develop capabilities for "real" geofluids, containing non-condensible gases and dissolved solids, as opposed to the idealization of modeling reservoir fluids as pure water (see the reviews by O'Sullivan, 1985; Bodvarsson et al., 1986); however, to this day geothermal reservoir simulators are limited to treating rather simple and idealized fluid mixtures.

SIMULATION METHODOLOGY

The basic steps in the development of numerical reservoir simulators are the following. First it is necessary to identify the fundamental processes controlling fluid and heat flows, and to develop mathematical equations for describing these processes in a quantitative way. Subsequently numerical algorithms must be devised and encoded in computer programs so that approximate solutions to the governing equations can be obtained. The viability of the simulation tool must then be demonstrated through applications to controlled and known systems (laboratory experiments, idealized flow problems which can be solved by analytical techniques). The ultimate test of the utility of reservoir simulators is of course in their application to the complexity of real geothermal fields.

In the early days of geothermal reservoir simulation many different approaches were pursued by different investigators (Pinder, 1979). However, over time there seems to have occurred a general convergence of methods, and the simulators presently in use share most of the basic characteristics.

The fundamental fluid and heat flow processes modeled by geothermal reservoir simulators are the following. There is pressure-driven fluid flow according to a multiphase extension of Darcy's law; sometimes higher-order terms are included to represent special gas flow effects, or high flow speeds in fractures near wellbores. Fluid flow is accompanied by transport of sensible and latent heat. Additional heat transfer occurs by conduction, and by means of heat exchange between fluids and rocks. Phase change effects and the accompanying strong latent heat effects are modeled by means of equilibrium thermodynamics. Conversion of compressible work into heat is also taken into account. The physical processes are stated in mathematical form as mass- and energy-balance equations. For numerical solution the continuous space- and time-variables are discretized, usually by finite differences, resulting in a set of coupled non-linear algebraic equations. Coupling terms as well as non-linearities often are strong, so that these equations must be solved simultaneously, using iterative techniques. The linear equations arising at each iteration step have been solved with direct or iterative matrix methods.

MULKOM and TOUGH

As specific examples of currently used geothermal reservoir simulation codes we consider LBL's MULKOM and TOUGH programs. "MULKOM" is an acronym for "multicomponent model," a family of computer modules for simulating the flow of multicomponent multiphase fluids and heat in permeable (porous or fractured) media (Pruess, 1983,

1988). The flow equations solved and the mathematical and numerical methods employed in MULKOM are similar to those in the SHAFT79 simulator (Pruess and Schroeder, 1980). The distinctive feature of MULKOM is its modular architecture (Fig. 1), development of which was based on the

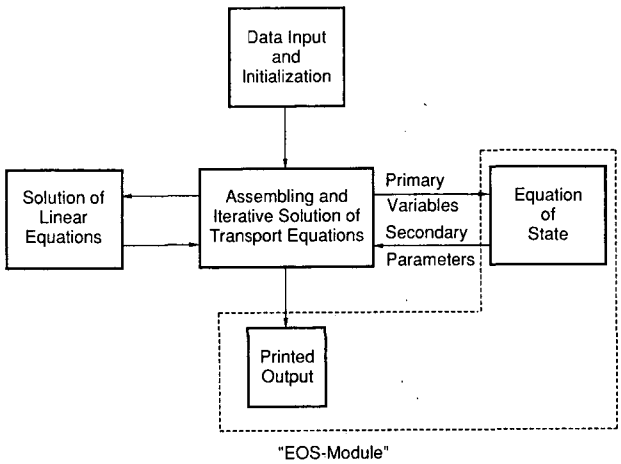


Figure 1. Modular architecture of MULKOM and TOUGH.

recognition that the transport equations governing flow of heat and multicomponent fluids have the same form, regardless of the nature and number of fluid components and phases present. This architecture enables MULKOM to simulate a variety of subsurface flow systems simply by interfacing the transport modules of the code with appropriate "equation of state" (EOS) packages for calculating the thermophysical properties of the desired fluid mixtures. This has provided a convenient and desirable flexibility for research applications (see Table 1), but it has also lead to a proliferation of specialized versions and program options. It is because of its status as a changing and evolving research tool, and consequent lack of documentation, that MULKOM has not been placed in general distribution; however, the code has been made available for research collaborations and to modelers who have acquired familiarity with the source code.

Table 1. MULKOM fluid property modules.

Components	Number of Components
water	1
water at near-critical conditions	1
two waters*	2
water, CO_2†	2
water, NaCl	2
water, air	2
water, SiO_2‡	2
water, volatile hydrocarbon, non-volatile hydrocarbon	3
water, natural gas, foam	3

* water with tracer

† with mineral buffer

‡ includes dissolution and precipitation, as well as associated changes in porosity and permeability

A thorough effort of code cleanup and documentation was undertaken for a set of MULKOM modules that simulate non-isothermal flow of water-air mixtures. This work was motivated by a desire to provide a capability for modeling the thermohydrologic conditions near a high-level nuclear waste repository in partially water-saturated geologic formations. To set this particular version of MULKOM apart it was given a special name "TOUGH," for **T**ransport **O**f **U**nsaturated **G**roundwater and **H**eat. The TOUGH user's guide (Pruess, 1987) includes a technical description of the code and its architecture. It also provides complete documentation for preparing input decks, and includes a set of sample problems which illustrate code applications. TOUGH can perform all the "conventional" (pure water) geothermal simulations simply by setting air mass fraction equal to zero in the input deck.(*)

MULKOM - RECENT ENHANCEMENTS

Silica redistribution

Rock-fluid interactions play a very important role in the natural evolution of hydrothermal convection systems, and they can have strong impacts on the response of geothermal reservoirs to exploitation. For example, precipitation of dissolved silica is believed to be the main cause of strong declines in flow rates of several wells at Cerro Prieto I (Truesdell et al., 1984). We have developed an EOS module which describes dissolution and precipitation of quartz based on the equilibrium solubility correlation given by Fournier and Potter (1982). A crucial aspect of silica redistribution is the impact of the associated porosity changes on formation permeability. Based on recent laboratory experiments (Vaughan, 1987) we concluded that for realistic modeling of permeability effects from mineral redistribution it is essential to take into account the converging-diverging nature of flow channels in "real" permeable media, as opposed to the idealization of flow channels with uniform cross section (see Fig. 2). Our capability to model silica redistribution has been applied to problems in nuclear waste isolation (Verma and Pruess, 1988); no applications to geothermal problems have been made yet.

Flow in fractured media

Despite major advances in recent years, the mathematical modeling of fluid and heat flow in fractured geothermal reservoirs remains a difficult problem. Porous medium approximations have been shown to be inadequate in many cases, while the method of multiple interacting continua (MINC; Pruess and Narasimhan, 1985) involves typically five

(*) TOUGH and associated documentation are available from the National Energy Software Center, c/o Argonne National Laboratory, 9700 South Cass Ave., Argonne, Ill. 60439.

times larger computational effort than porous medium models.

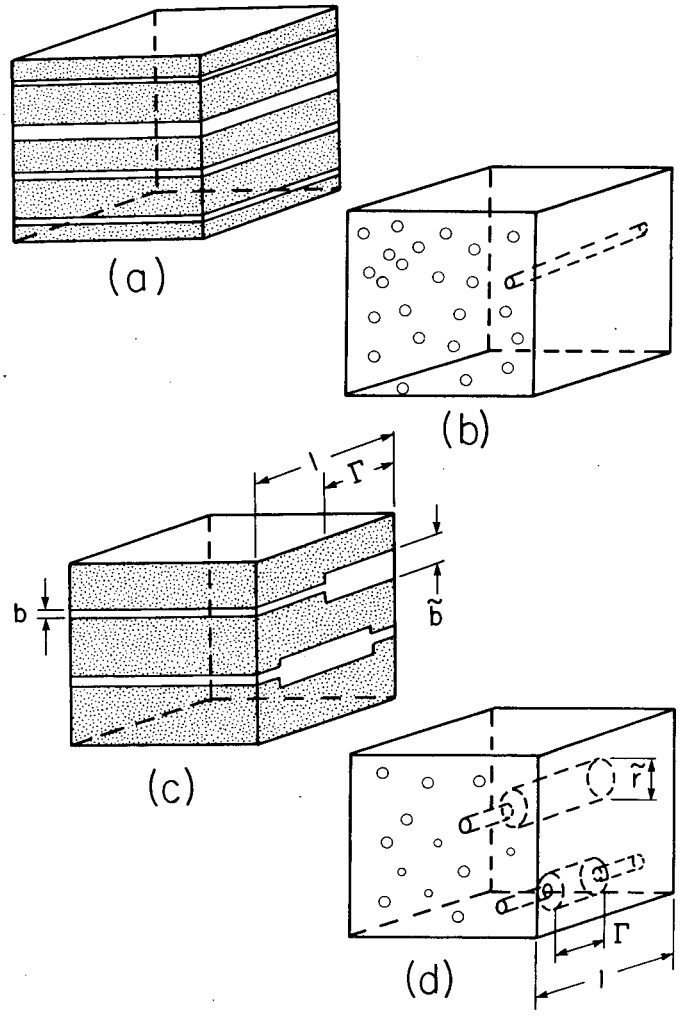


Figure 2. Models of pore channels for development of porosity-permeability relationships.

Combining finite-difference and analytical techniques, we have developed a method which can provide an accurate and efficient representation of fluid and heat flow in fractured reservoirs under conditions of strong heat transfer and insignificant fluid exchange between rock matrix and fractures (Pruess and Wu, 1988). A fractured medium is conceptualized as impermeable rock blocks embedded in a porous medium (Fig. 3); the latter representing the network of interconnected fractures. Rather than discretizing the matrix blocks as in the MINC-method, the temperature distribution in the blocks is modeled by a simple trial function, the parameters of which can be easily determined from principles of energy conservation and continuity of heat flux at the block surfaces. As shown by Pruess and Wu (1988), this semi-analytical approach can give accurate results with no noticeable increase in computational work compared to porous medium models. An extension of this approach to permeable matrix blocks appears feasible and is currently under development.

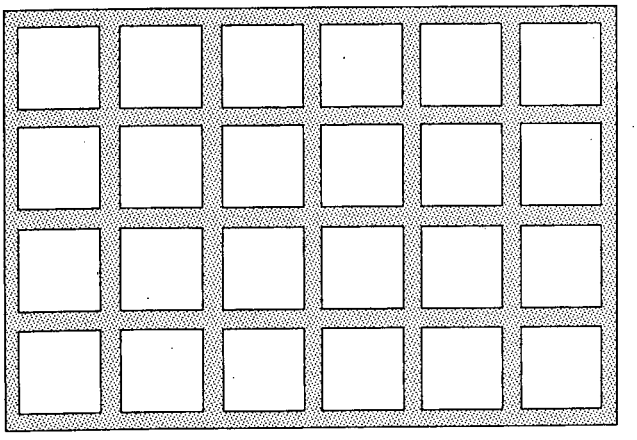


Figure 3. Conceptual diagram of a fractured medium, with impermeable blocks embedded in a porous medium.

Near-critical flow

In deep zones of geothermal systems temperatures in excess of the critical point (374°C for pure water, higher for saline brines) have been encountered (e.g. Cappetti et al., 1985). Laboratory studies have suggested that fluid convection at near-critical conditions can play an important role in enhancing overall heat transfer in a process dubbed "superconvection" (Dunn and Hardee, 1981). In an effort to gain insight into near-critical flows we have developed special numerical techniques for dealing with the extreme nonlinearities in water properties near the critical point.

Initial simulation studies for the flow geometry studied in the laboratory experiments of Dunn and Hardee (1981) indicated heat transfer enhancements by up to a factor of five (Cox et al., 1988). Ongoing work is addressing the question as to whether superconvecting zones can occur over significant space- and time-scales during the evolution of hydrothermal convection systems.

SIMULATOR APPLICATIONS

Geothermal reservoir simulators have been used to model laboratory experiments, to study fundamental aspects of geothermal reservoir dynamics, and to perform simulation studies for specific geothermal fields. Although only few applications to laboratory experiments have been made, these are important for confirming the basic physics of fluid and heat flow incorporated into the simulator (Verma et al., 1985; Lam et al., 1988). The study of reservoir dynamics has been a fruitful application of numerical simulators (see Table 2), and has helped in developing a better understanding of fluid and heat flow mechanisms in geothermal reservoirs. Issues in well testing of nonisothermal multiphase systems have been clarified, and basic insights into the exploitation of different kinds of geothermal systems have been gained.

From a practical viewpoint the most interesting applications of reservoir simulators are for history matching and performance prediction of specific geothermal fields. A number

Table 2. Advances in Reservoir Dynamics from Numerical Simulations

- Pressure decline in the depletion of boiling reservoirs
- Evaluation of boiling and condensation zones
- Exploitation strategies
- Liquid-vapor counterflow systems (vapor-dominated and liquid-dominated heat pipes)
- Transition from liquid-dominated to vapor-dominated conditions
- Natural evolution of hydrothermal convection systems
- Fluid and heat transfer in fractured-porous media
- Non-isothermal and two-phase well testing
- Effects of reinjection and natural recharge
- Non-condensible gas effects

of field case studies have been published (see the recent review by Bodvarsson et al., 1986), and a considerably larger number remains unpublished because of proprietary restrictions on the data. We believe that the existing studies have shown that it is indeed possible to build sufficiently quantitative and reliable models of geothermal fields to be able to obtain useful guidance for field development and management.

SIMULATION TOOLS: MAJOR FUTURE IMPROVEMENTS

With geothermal reservoir simulation software and services in routine commercial use, it is of interest to speculate on future trends and possibilities in this field. Where is a need and a potential for major improvements in our simulation tools and their use? What are the possibilities and benefits for realizing improvements near-term as well as long-term? What role and priorities should DOE adopt in furthering reservoir simulation technology?

Generally speaking, it would be desirable for simulators to become more realistic and comprehensive in their representation of physical and chemical processes in geothermal reservoirs. At the same time execution speed and ease of use should be improved.

Table 3 lists a number of specific items that should be considered for mapping out future research directions. Some fundamental reservoir processes require better definition. An example is multiphase flow in fractures, which is the dominant production mechanism in most high-temperature geothermal fields. Yet next to nothing is known about two-phase flow in "real" rough-walled fractures; an effort to develop laboratory experiments in this area has been initiated at LBL to supply some of the basic information needed. The coupling of chemical and mechanical processes to hydrology is not usually included in geothermal reservoir simulators, and geochemical and geophysical data are not usually input to or predicted from fluid and heat flow simulations (second point in Table 3). A broadened scope, possibly also including flow

Table 3. Possible future improvements in geothermal reservoir simulation technology

(1) Better definition and more complete description of reservoir processes

(2) Broadened scope (geochemistry, geophysics)

(3) Improved mathematical and numerical techniques

(4) Better user interface/data handling

(5) Application of expert system concepts (artificial intelligence)

(6) More complete and reliable field data

(7) Better application methodology through broader track record

in wellbores and surface lines, could lead to more comprehensive and realistic reservoir models. Another area of possible improvement is in the mathematical and numerical techniques. Most of the numerical work in reservoir simulation is expended in the solution of large systems of linear equations. If this could be accomplished more efficiently it would be possible to improve the geometric definition and realism of simulations, especially for three-dimensional problems. Furthermore, more chemical species could be included in flow models. Improved capabilities for tracking sharp phase or composition fronts are also desirable.

A reservoir simulation effort involves working with large amounts of data which is a tedious and time consuming process. One could expect that substantial gains in efficiency may be possible from appropriate interactive and graphic techniques. The fifth point in Table 3, expert systems, relates to both broadened scope and better user interface. In the development of a simulation model of a geothermal field the reservoir engineer attempts to integrate and synthesize large amounts of information from different scientific and engineering disciplines. Help and advice from geologists, geochemists, and geophysicists is needed in this task. Expert systems could offer a way to make such multidisciplinary advice available at a desktop terminal in a convenient and efficient way.

A notorious bottle-neck in numerical simulations has been field data. Future improvements in this area can be expected not only from advances in high-temperature instrumentation, but also from better analysis of existing data. Most reservoir engineers would agree with the proposition that a reliable prediction of reservoir performance could be achieved if only sufficiently detailed and reliable data on the thermodynamic and hydrologic structure of a geothermal field were available. Therefore, it would appear that improvements in quantity and quality of field data could have a large impact on the utility and benefits of simulation studies; however,

such improvements may be costly and slow to develop. The final point in Table 3 suggests that continued building of a track record of publicly available simulation studies will improve our understanding of how to best use reservoir simulators and the results from them.

When examining possible future improvements in geothermal reservoir simulation technology due consideration should be given to institutional aspects. It is important to identify the proper role of government laboratories, universities, and private companies so that maximum technical and economic benefits can be obtained from future research.

ACKNOWLEDGEMENT

For a critical review of the manuscript the author is grateful to Drs. M. Lippmann and C. Suarez. This work was supported by the Geothermal Technology Division, U.S. Department of Energy, under Contract No. DE-AC03-SF7600098.

REFERENCES

Bodvarsson, G. S., K. Pruess, and M. J. Lippmann, 1986. "Modeling of Geothermal Systems," *J. Pet. Tech.*, Vol. 38, No. 10, pp. 1007-1021.

Cappetti, G., R. Celati, U. Cigni, P. Squarci, G. Stefani, and L. Taffi, 1985. "Development of Deep Exploration in the Geothermal Areas of Tuscany, Italy," 1985 International Symposium on Geothermal Energy, International Volume, Geothermal Resources Council, pp. 303-309.

Clemo, T. M., 1985. "FRACSL Code Development and Correlation of East Mesa Test Results," Proc. Tenth Workshop Geothermal Reservoir Engineering, Stanford University, pp. 287-292, Stanford, CA.

Cox, B. L., K. Pruess and R. McKibbin, 1988. "Mathematical Modeling of Near-Critical Convection," presented at Thirteenth Workshop on Geothermal Reservoir Engineering, Stanford University, January 19-21.

Dunn, J. C. and H. C. Hardee, 1981. "Superconvecting Geothermal Zones," *J. of Volcanology and Geothermal Research,* Vol. 11, pp. 189-201.

Fournier, R. O. and R. W. Potter, 1982. "An Equation Correlating the Solubility of Quartz in Water from 25°C to 900°C at Pressures up to 10,000 Bars," *Geochim. Cosmochim. Acta,* Vol. 56, pp. 1969-1973.

Lam, S. T., A. Hunsbedt, P. Kruger and K. Pruess, 1988. "Analysis of the Stanford Geothermal Reservoir Model Experiments Using the LBL Reservoir Simulator," *Geothermics,* Vol. 17, No. 4, in press.

Miller, J. D. and D. W. Allman, 1986. "Dual Permeability Modeling of Flow in a Fractured Geothermal Reservoir," Proceedings, Eleventh Workshop Geothermal Reservoir Engineering, Stanford University, Stanford, CA, pp. 77-84, January.

O'Sullivan, M. J., 1985. "Geothermal Reservoir Simulation," *Energy Research,* Vol. 9, pp. 313-332.

Pinder, G. F., 1979. State-of-the-Art Review of Geothermal Reservoir Modeling, Lawrence Berkeley Laboratory Report LBL-9093, March.

Pruess, K., 1983. "Development of the General Purpose Simulator MULKOM," Annual Report 1982, Earth Sciences Division, pp. 133-134, Report LBL-15500, Lawrence Berkeley Laboratory, Berkeley, CA, September.

Pruess, K., 1987. TOUGH User's Guide, Nuclear Regulatory Commission, Report NUREG/CR-4645, June. (also Lawrence Berkeley Laboratory Report LBL-20700, Berkeley, CA, June).

Pruess, K., 1988. "SHAFT, MULKOM, TOUGH: A Set of Numerical Simulators for Multiphase Fluid and Heat Flow," *Geotermia, Rev. Mex. Geoenergia,* Vol. 4, No. 1, pp. 185-202, April 1988, (also Lawrence Berkeley Laboratory Report LBL-24430).

Pruess, K., and T. N. Narasimhan, 1985. "A Practical Method for Modeling Fluid and Heat Flow in Fractured Porous Media," *Society of Petroleum Engineers Journal,* Vol. 25, No. 1, pp. 14-26, February.

Pruess, K., and R. C. Schroeder, 1980. SHAFT79 User's Manual, Lawrence Berkeley Laboratory Report LBL-10861, Berkeley, CA, March.

Pruess, K. and Wu, Y. S., 1988. "A Semi-Analytical Method for Heat Sweep Calculations in Fractured Reservoirs," presented at Thirteenth Workshop on Geothermal Reservoir Engineering, Stanford University, January 19-21 (LBL-24463).

Stanford Geothermal Program (ed.), 1980. "Proceedings Special Panel on Geothermal Model Intercomparison Study," presented at Sixth Workshop on Geothermal Reservoir Engineering, Report SGP-TR-42, Stanford University, December.

Truesdell, A. H., F. D'Amore, and D. Nieva, 1984. "The Effects of Localized Aquifer Boiling on Fluid Production at Cerro Prieto," *Geothermal Resources Council, Transactions,* Vol. 8, pp. 223-229.

Vaughan, P. J., 1987. "Analysis of Permeability Reduction during Flow of Heated, Aqueous Fluid through Westerly Granite," in C. F. Tsang (ed.), *Coupled Processes Associated with Nuclear Waste Repositories,* pp. 529-539, Academic Press.

Verma, A. K., K. Pruess, C. F. Tsang and P. A. Witherspoon, 1985. "A Study of Two-Phase Concurrent Flow of Steam and Water in an Unconsolidated Porous Medium," Proc., 23rd National Heat Transfer Conference, Am. Society of Mechanical Engineers, pp. 135-143, Denver, CO, August.

Verma, A. and K. Pruess, 1988. "Thermohydrologic Conditions and Silica Redistribution near High-Level Nuclear Wastes Emplaced in Saturated Geological Formations," *J. Geophys. Res.*, Vol. 93, No. B2, pp. 1159-1173.

PANEL DISCUSSIONS

Panel Members

Jill Robinson-Haizlip (GEO) — Chairperson

Ronald C. Schroeder (BGI)

Joe L. Iovenitti (Consultant)

John P. Ziagos (GEO)

Brian A. Koenig (Unocal)

Sabodh Garg (S-CUBED)

Jill Robinson-Haizlip (Chairperson)
GEO Operator Corporation

The main purpose of this panel is to summarize the discussions and suggestions presented during the meeting and to make recommendations on the type of research which should be supported by the DOE Hydrothermal Research Program.

I will ask everyone on the panel to identify themselves and mention their "biases." In other words, indicate whether you are a geologist, geochemist, etc., and whether you are with a specific company or are a consultant. Then, you should in a matter of a few minutes, summarize your thinking about priorities for DOE funding in the near or long-range future.

I think we should go quickly down the row and then we will open it up for discussion. Please keep in mind that the objective of this panel is to come up with recommendations. This is a non-trivial exercise; there might be some real dollars behind it.

Ron Schroeder
Berkeley Group Incorporated

I am a consultant; my company develops software for geothermal use. I have several points based on the discussions and presentations that were made, as far as research that I think would be helpful to me and to geothermal in general.

During the past couple of years I have been doing tracer test analysis and currently have a tracer test underway. From my standpoint, adsorption and dispersion remain a fairly unsolved problem in tracer analysis.

Which tracers are best to use is also a real problem, although I think UURI has been working on this and will someday solve the problem. We use halite and we have run into a problem that Mike Wright mentioned. It is the poor resolution; one ends up having a lot of noise in the data. In a multi-well tracer test you really cannot get enough tracer to the production wells. So, as far as tracers are concerned, we need new tracers that have lower limits of detection. Some really basic research in tracer adsorption and dispersion might help solve that problem.

On another mode I do a lot of modeling. For both wellbore simulators and reservoir simulators, a relatively simple but accurate equation-of-state for Salton Sea brines would be a big help. I think Don Michels mentioned his approach to it yesterday, and those of us who do modeling on the Salton Sea reservoirs have developed our own ways to handle this. But, from my standpoint anyway, none of it is really adequate or as accurate as for water.

As far as the computer simulators and models that DOE develops are concerned, making the models available to everyone is a concern to developers, but if they are made available to everyone, then Sabodh Garg and John Pritchett would have access to them, as well as other people who develop simulators. So it seems that it would be a benefit to everyone. Also along those lines, we really need to get the simulators down onto the new high-speed high-capacity microcomputers. Microcomputers are coming on-line in a month or two that are going to be running at 25 Mhz and they now have enormous memory and disk drive capacity. The direction to be going is to get the simulators off the supercomputers that cost so much.

Then the last thing on my list is welltest analysis. There have been some new directions over the past couple of years in the oil patch welltest analysis, and they have potential application in geothermal. But, as Sally Benson said earlier, we need more accurate field data to be able to differentiate that data and use these new methods.

Finally, as far as welltest analysis is concerned, Karsten Pruess and Marcelo Lippmann have referred briefly to artificial intelligence, but they have not mentioned that there is an expert system being developed at LBL for welltest analysis. I think it has terrific potential. You really need to see a demonstration of it in its infancy to appreciate what artificial intelligence and expert systems can do in the future. Not only for welltesting, but, for example, well logging and interpretation of surface geophysical measurements. There is a computer program (expert system) that was developed by the USGS called Prospector. What this expert system does is process all of the geology, lithology and mineralogy data, and everything known about a particular area, and determines the potential for certain mineral deposits there. The same kind of artificial intelligence system could be developed for finding or evaluating potential geothermal resources. The way these expert systems work is that the computer is given a set of rules which the computer uses along with the input data to determine the most likely answer to a problem. In the case of well testing, for example, the computer has a set of rules based on certain straight lines in the welltest analysis data; many different rules are built into this expert system. Then, the system works away and comes back and says (for example) that it is probably a dual porosity reservoir or whatever the data indicates. In the ideal case it will probably indicate kh and ϕch between some limits, and so on. That is what an expert system can do, and that is what it could do for potential geothermal resources, for example. So, it is a research area that would be very appropriate for DOE to pursue.

Joe Iovenitti
Consultant

I am currently a geological consultant to the geothermal industry. I have been involved in geothermal work for 11 years. During the first four and a half years, I was doing exploration and development work, and for the last six and a half I have principally conducted development production type activity.

One of the ways that I think DOE could help the geothermal industry is in providing additional case histories. I believe that it is imperative that we, geothermal geoscientists, understand what geoscientific techniques work and what do not, in any given field application. Related to this are the causes and effects of any given technique. For example, electrical resistivity surveys have been suggested to be useful in geothermal reservoir definition. Often, however, the results are very ambiguous with respect to both depth of penetration and resolution. We need to better understand why this is the case and develop methods to overcome these limitations.

In my opinion, the Los Azufres work reported at this meeting is very exciting. This is a field where a considerable data base exists and a wide variety of valuable research can be accomplished. I would suggest that a strong multidisciplinary approach (along the lines of the Cerro Prieto study) be taken to critically study the Los Azufres field. For example, instead of just having Sally Benson and some of the people at LBL reviewing welltest information, we should be integrating this work with geology. Sally reported the phenomenon of permeability increasing in some wells during the injection. Is this feature related to structural position in the field, lithology, or both? It is of interest to know.

Reviewing the results of the survey discussed by Marshall Reed, I believe a number of the comments reduce to the following:

1. What is the permeability distribution in a given geothermal system?
2. How does that permeability distribution affect production?

It is the basic question of the framework of the geothermal reservoir. Geology is needed to initially address this problem. However, geology will only go so far to resolve this issue, in and of itself. I believe that we must fully integrate the geological results (including geophysics, geochemistry and hydrology) with those derived from reservoir engineering analyses. It is crucial to develop a three-dimensional representation of the permeability distribution in a geoth-

ermal system. Anything short of this may result in a limited view of the total picture. The consequence could be less than optimal field decisions.

One of the negative assessments I have made today is in the area of instrumentation. It appears that each laboratory is developing its own instrumentation and I wonder how much duplication of effort exists. Can DOE better focus its limited funding on generic instrumentation that can serve a number of different purposes?

To sum up my perspective on where DOE should be focusing their limited geothermal funds, I believe that cooperative programs with industry and with foreign governments are the way to go. They allow the stretching of limited funds, and make available data that are not normally accessible.

John Ziagos
GEO Operator Corporation

I am a geophysicist; I have recently joined GEO. Previously, I spent seven years in the oil business, working for Standard Oil in San Francisco, and the Dallas Research Center in the Reservoir Description/Characterization Group. Before that, I worked with the USGS in the Geothermal Program. So actually, I have been in geothermal since 1973, but I took a hiatus for about seven years.

As I mentioned during the discussion sessions, I think the most important area of interest for geothermal energy is to research new geophysical techniques to monitor producing reservoirs. I would like to see DOE look into this area. One of my motivations is that it takes a lot of money to use seismic techniques, which is what most companies are using right now. Maybe there are techniques to do it cheaper. That could include borehole or cross-borehole electrical techniques, and other methods mentioned in the survey described in Marshall Reed's paper.

Another area I would be interested in DOE looking into is source mechanisms for microseismic events. It is important because one must decide whether to drill into the cloud of seismic events or out of it, and the type of mechanism would make the difference. The questions for DOE in this area are, what mechanisms are there that create these events and how can we sort them out from the data itself?

Also, as I mentioned before, I would like to see some way of determining fracture azimuths when we have a dry steam hole as we find at The Geysers. Is there any way of doing that, any tools or methods that could be used? DOE could work on these problems.

The last issue is that I would like to see cheaper hardware/software solutions to microseismic monitoring.

Brian Koenig
Unocal Geothermal Division

I work primarily in geochemistry and my major efforts are devoted towards the study of vapor-dominated systems. So, there are a few suggestions I would make that apply to steam systems.

Despite my biases with respect to geochemistry, I am very much concerned about the three-dimensional fracture distribution in geothermal systems and our ability to discern and understand it. A lot of the effects that we see are governed by the nature and direction of fluid movement. Many aspects of reservoir behavior at The Geysers that are puzzling us relate to the characteristics of the fracture network. I am especially concerned about how fracture distribution changes with depth, and what happens below presently drilled depths. What methods are available to elucidate these characteristics for us? We can not go out and drill a 20,000 ft well just to test the fractures in a given area.

Another area I think would be important was mentioned by Karsten Pruess in terms of his simulation work. I would also be very curious to have a much better understanding of the actual physics of reservoir processes. I would like to understand them well enough to be able to couple these processes with geochemical features of a system, and use changes in those geochemical features to reliably predict what is occurring as a result of exploitation. I think this is a major problem when talking about how noncondensible gases distribute themselves between a liquid and a vapor in a vapor-dominated system. When we try to monitor these gases, it is easy to collect them at the surface. Interpreting the data, and determining exactly what the changes mean, is dependent upon what is actually happening on a local reservoir scale, perhaps down to the pores feeding fractures in a dual porosity type of model.

I would like to see a much greater coupling of geochemical capabilities with simulation because I would be very interested in being able to model what is happening in terms of mineral deposition. I have some skepticism with regard to the mineral buffers in vapor systems being capable of keeping up with the rate of exploitation.

Another issue that Alfred Truesdell discussed is the hydrogen chloride problem that we are experiencing at The Geysers. I know it is not unique to The Geysers; it is certainly happening in other geothermal systems in the world. Even as certain liquid-dominated systems are exploited they create steam caps, and it would be very much of interest to know more about this problem from both the mechanism of generation and from a detection standpoint. If you are trying to look at it in a producing field like The Geysers, how does one detect it downhole? Is there a way of understanding more about what is occurring in the reservoir and the generation of this material? Alfred Truesdell is looking for distribution coefficients. I think that is certainly one part of the problem, but not the only approach. An easier, more reliable method would be to lower something downhole that is capable of detecting a relatively small amount of a specific corroding agent. I think this would be of interest. Possibly something to do with an application of the optrode concept discussed by Mike Angel.

Lastly, I would like to comment, along with what John Ziagos was mentioning earlier, that I think it would be of interest to have geophysical methods in regular use to monitor fields and understand how geophysical parameters change with reservoir exploitation. It would be very helpful to have a method, and one probably would have to rely on something like geophysics, for defining where the bottom of the reservoir is and what the bottom reservoir boundary is. These are very important problems in order for us to understand things like how injection fluids move, and what limits those fluids are going to encounter in their transport properties.

Sabodh Garg
S-CUBED

My principal interests are reservoir engineering and rock mechanics. My colleagues on the panel have mostly covered what I was going to talk about, so I can be brief.

As a modeler I am particularly conscious of the fact that a lot of things we put into our models we do not understand. One of the first things that strikes me is that after all of these years of geothermal work we do not know what relative permeability curves to use. I feel that the time has come to look at field, as well as lab test data, compile that information and see what we can learn about relative permeabilities.

The second issue that I have started confronting the last couple of years as I have looked at more and more pressure transient data, is how little we understand pressure transient tests in geothermal reservoirs. Here, I am thinking of problems such as partial penetration. A geothermal well does not penetrate a rock which is homogeneous, and it produces fluid from only a few points along the borehole. We need to understand how these feed zones couple with the rest of the fractures. As mentioned earler by Bo Bodvarsson, we frequently find, at least by word of mouth, that the interference tests give higher kh values than single-well tests. There is a need to understand why this is so.

Along the same lines, I feel that we do not understand at all too well what boiling does to our pressure test interpretations. Recently, John Pritchett and I did a little bit of work on pressure transient tests in two-phase reservoirs and we found that the traditional methods could lead to rather large estimates of permeability-thickness products in interference tests, which are not justified.

Finally, I would also like to bring up the issue of reliability and uniqueness of our models. How do we constrain them? Can we say they are unique? Can we put a limit on their reliability, some percentage probability? How do we go about saying whether we believe a model is robust or is just something that fits the past data and may or may not be useful for future predictions?

Jill Robinson-Haizlip
GEO Operator Corporation

I am a geochemist with GEO. I would like to suggest something that was brought up in the geochemistry session yesterday. One of the biggest problems for people working on the geochemistry of geothermal systems is getting their hands on chemical models which are reliable, easy to use, and have been constrained

somehow by reality. This was brought up when we were talking about reservoir simulators and the testing of these models to find out if they work. I would like to see the same kind of evaluation with some of the chemical models to determine what the relationship is between what we are actually seeing in the field and what these models predict. This is because in industry we have to make a lot of decisions long before we can observe what actually happens. We have to concentrate on the predictive qualities of both reservoir simulators and chemical models. One of the ways I think we can get at that is to take the myriad of chemical models that are available and try to compare them with some actual field data, as well as with each other, and come up with which ones are the best. Do we really need these complex models that John Weare presented for hypersaline brines for simple low-salinity systems?

The other point is to consider DOE funding to make one of these models user-friendly, as we discussed in the case of the reservoir simulators.

With regard to the Broadlands experiment that Bo Bodvarsson mentioned, I think it would be very possible and very interesting to try to repeat that experiment with much more extensive chemical data collection in a well somewhere here in the U.S. This would be a good DOE/industry cooperative program. The ultimate goal would be to couple geochemistry to some of the reservoir simulators, as, for example, when interpreting wellhead data and fluid samples taken during simple flow tests. In many instances these tests are our only chance to get data from which we have to predict scaling, estimate the life of the whole field and establish design parameters for the power plant. Anything we can do to improve the predictions of the composition of the fluid delivered to the power plant, would really be helpful. I think that, to date, predictive reservoir modeling has focused on the interpretation of physical data collected during flow test. Most of us who work in the field collecting chemical samples and data during the flow tests, would like to determine the relationship between the chemical and physical wellhead data.

I also agree that we need to continue field case studies. But we should also relate some of the data of these long-term case studies with the models and simulations to emphasize predictions. It is really great to find out what happens after 10 or 15 years, but when you are starting out in a development project, it would be very interesting to know what parameters were predictive and might not have been noticed at the time, but which we could now use.

Finally, Alfred Truesdell had to leave, but he asked me to add that he would vote for extending the DOE/CFE agreement. As an industry person, I consider that this would be good for everyone. Unless there is an area or an industry group within the U.S. which is willing to release a volume of data similar to what is available in Mexico, I do not think we can otherwise get the kind of integrated field-wide case studies that we have from Cerro Prieto and Los Azufres. However, ideally, it would be most cost effective for the U.S. geothermal industry to have any future programs of this scope in the U.S.

I think we can open up the session to comments and questions. Do not forget that the results of these discussions are going to be used to determine some funding directions. You can direct your questions or comments to the individuals on the panel or expand on their previous comments. I am sure there are things that the panel has left out.

Open Discussions

Don Michels
Consultant

I think I would like to first try extending what has been said about testing. Typically, after wells are drilled, they are tested for a short period of time and the samples may be of good quality or not. One of the interesting things about the chemistry is not that we are looking for a magical composition to represent the reservoir and then do all kinds of equilibrium calculations from it. I think that is trivial and not really getting the point.

We are interested mainly in reservoir engineering, and how chemistry can amplify that. If you look at the transients in fluid composition and interpret those in terms of what the spinner surveys are telling us, and also in terms of the fluid loss during drilling, we can get some sense of how the reservoir is put together. This is related to mixing models; it is not really chemistry. I think that if we are going to do some forecasting, we could help by integrating

the chemical data and using those contaminations from drilling and workover fluids as tracer tests. Then, integrate the chemical data (not necessarily the geochemistry), with the reservoir engineering to help us make some forecasts.

Secondly, the Mexican data and the DOE/CFE agreement were mentioned. That is not the only agreement. For example, Honduras is being investigated by LANL. So, there is a data package there, and there are other Central American developments. Some are funded by AID or others, and it may be possible that the notion of getting foreign data for review is feasible on many fronts. It is just a matter of making an agreement to get the information and finding someone to analyze it.

Mike Wright
University of Utah Research Institute

I want to comment about case studies too. Last fall, John Rowley, as a committee of one, appointed me to head an effort to write a new geothermal exploration technology textbook. I asked some people to serve on a committee and we got together last December and decided that a new textbook on geothermal exploration was not needed or wanted, but there was interest in a publication of case studies. So, there is an effort now to produce a book, under GRC auspices, to be published sometime after the 1990 meeting in Hawaii. The book would have five, or possibly six, fairly detailed case histories from operating fields throughout the world.

What we are aiming at is the history of fields that have enough production and enough of a high quality data package that one can start to see what is going on. We are talking possibly about Cerro Prieto, a field in Japan, a field in New Zealand, etc. I think that will produce a lot of data compiled in a way that people can use it. I will certainly take back to that committee everybody's concerns at this meeting, and it sounds to me that we may be on the right track. I would also be interested in any specific suggestions that any of you might have for where to look for data, which fields to study, who could help us write these case histories, what to include in them, and what really is the pertinent thing we should be getting at.

Jill Robinson-Haizlip
GEO Operator Corporation

I would like to make a quick comment on that. There have been comments about integration of data, particularly geology, and Mike Wright mentioned exploration. That reminded me that I wanted to comment on Ron Schroeder's mention of artificial intelligence and exploration. Unfortunately, I do not think that exploration is a big push for this industry in the next few years. But, in the interim, something like Ron described could certainly be useful for welltest analysis and some other smaller types of projects.

John Pritchett
S-CUBED

I have what amount to three utterly disjointed comments, so I will present them in random order. During this meeting, I have heard several times about the potential applicability of geophysical survey methods to monitor operating geothermal fields during their lifetime to try to determine what is going on. One topic that did not come up in those discussions was gravity. I remember that there was an exciting paper presented by Paul Atkinson at the last Stanford geothermal workshop in January. Apparently, small portable gravity meters now exist that are cheap and accurate, such that one can think about going back and resurveying a field every year to try and detect the change in density due to the inflow of cold recharge water. Now this is something that can be done inexpensively, and is easy to analyze. Maybe DOE should be interested in funding someone to look at repeated gravity surveys from the reservoir-monitoring standpoint.

Another comment concerns something that has been bothering me for a long time. It seems to me that the property that we most need to know about any geothermal system is its temperature, and that is something that we usually do not know very well. There are basically two ways to get at reservoir temperature; one is to try to measure it directly, and the other is to attempt to estimate it chemically. Often, however, chemical data are either not available or of poor quality. Typically, you wind up confronted with a whole series of heat-up survey profiles in wells in which someone has first injected cold water and then, after shut-in, lowered a thermistor down after 8, 12, 24 and

48 hours, and so on. People try to estimate the formation temperature distribution from those measured profiles. There are some real problems in doing that, as I am sure everyone knows. There can be crossflow in the wells; there can be insufficient shut-in time to reach equilibrium. Even in the cased part of a well, buoyant circulation can occur inside the wellbore that will redistribute temperatures vertically. So, another topic that DOE might consider looking at is what can be done to understand the differences between an "equilibrium" temperature distribution in a shut-in well and the temperature distribution in the formation outside. I know this problem was looked at a long time ago, but maybe somebody has learned something since then.

The other comment I have has to do with numerical reservoir simulation. I seem to be hearing mixed signals from people about what they want out of simulation. On the one hand, we seem to want programs that will fit on $2000 PCs. On the other hand, we want to incorporate MINC-type fracture/matrix models into our simulators (turning three-dimensional problems into four-dimensional ones). We sometimes even want to add chemical reactions; if we take the estimate that we heard yesterday about approximately eight additional chemical degrees of freedom, then we go from having two simultaneous equations to solve to ten, which makes the problem enormously harder. Suppose one were to try to do a multiphase, unsteady implicit three-dimensional simulation of a large reservoir with thousands of gridblocks coupled with a MINC model and ten balance equations. There are not enough Crays in the world to solve the problem before the end of the century, and that situation is not likely to change in the foreseeable future. So, I think what is really needed is effort along two different lines. To do reasonable, practical, everyday reservoir simulation we have to use relatively simple simulators without too many mass balances. If these other effects (MINC-models, chemistry, etc.) are of interest, they should be studied in the "computer cartoon" sense. For example, one-dimensional studies should be done to look at phenomenology and to try to understand what is going on, to develop useful rules-of-thumb for application to reservoir-scale modeling.

Gudmundur (Bo) Bodvarsson
Lawrence Berkeley Laboratory

I just want to make another "sales pitch" for the Philippines field data. I am happy that the panel members seem to think that case studies are worthwhile because for most of us at LBL and some of you, that is probably how we get most of our research ideas. The reason I liked the data from the Philippines is that the quality is much better than what I am used to. I was extremely impressed when I went to the Philippines last November and learned about the availability of high quality pressure transient data, the chemical monitoring of the production wells, and the tracer tests they have done. For example, in one case they injected 10 kg of dye into a well, which was detected in 10 other wells one km away. Ten kilograms of dye is a very small amount.

So, the pitch I am going to make is this: PNOC has offered to send some of their people to LBL to learn about our research methods, and to cooperate with us. They are willing to give us the data to look at for theoretical research problems. For example, we are interested in studying the effects of reinjection, for which they have a very good data set. I believe that we really would benefit from this cooperative project, especially if we can publish the results as a case study.

Marcelo Lippmann
Lawrence Berkeley Laboratory

I would like to respond to some of the comments made this afternoon. During the meeting we have not described all the activities of our group at LBL, just those supported by the Geothermal Reservoir Technology Program. For example, we are involved in several research projects studying the underground storage of radioactive wastes.

A few years ago, the DOE nuclear waste storage program was learning from the results of the DOE geothermal program. Because of a major change in priorities in the department the situation has reversed; now geothermal can take advantage of some interesting research projects being conducted under the waste program. The expert system being developed at LBL for interpreting well test data, described by Ron Schroeder, is just one of them. I am sure the results we will be getting from that system will

be useful for evaluating geothermal reservoirs.

A question that was asked was, what is the bottom of the reservoir? Karsten Pruess is studying this topic, and has published a paper in the proceedings of the 1987 Stanford Workshop. If you are interested, you should talk to Karsten.

Several people suggested that DOE should carry out more multidisciplinary studies, field work and monitoring work. One should remember that these projects are expensive, and that the DOE geothermal budget, especially for hydrothermal research, is decreasing. Therefore, if you feel that certain aspects of the geothermal research supported by DOE are of interest and value to your organization, I encourage you in industry to make it known to DOE management and to those overseeing DOE program budgets and policies.

John Ziagos
GEO Operator Corporation

I just wanted to comment about expert systems. I was lucky (or unlucky) to be involved in the development of an expert system at Standard Oil, and my experience is that there are two problems. One is that you have to find a person everyone agrees is an expert. Otherwise no one will use the system, because the system is essentially just that person's ideas. And it is hard to get people to agree on that.

Secondly, people do not trust the answer of a computer no matter if you tell them it is an expert system or not. We spent a lot of money and effort to build one of these systems and had trouble with people using it. So, it is just sitting there and the person who built it uses it and that is it. One should be careful. We thought everybody would love the system and be using it, and no one did.

Roland Horne
Stanford University

I have a comment about expert systems too. We have completed a well testing expert system that was funded not by DOE but by an industry consortium, which does the things that you were asking, including estimating the reservoir parameters. It is sensitive, furthermore, to parts of the data that do not mean anything. It knows how to ignore things it does not understand. But we have not ever thought of using it for geothermal for the same reasons that Bo Bodvarsson was talking about. We actually do not have experts in geothermal well testing yet. Trying to capture that when it does not exist might be far off into the future. We can make expert systems for testing oil and gas wells, and have done it, but I think geothermal is some distance off yet.

Ron Schroeder
Berkeley Group Incorporated

I would like to add to Sabodh Garg's comment on relative permeability. And again, repeat some of the points about the fundamental physics of tracer testing, and some of the parameters needed in analyzing tracer data. It seems to me that DOE, especially with a small budget, is in a good position to do research of this kind, to determine fundamental parameters, to do basic research in the laboratories, to go through the data and find out what the correct relative permeability should be. Those are relatively small budget items. DOE should be doing these types of projects focused on basic reservoir physics. We have mentioned some of them: relative permeability, dispersion, adsorption, what tracers to use. These are basic features that one could put into simple reservoir models.

Marshall Reed
Department of Energy

I would like to explain some of the constraints placed on federal funding of industry research. We have great difficulty in funding any research group except a national laboratory without having a competitive solicitation. Each DOE office has a "competition advocate" to insure that all procurements are open to all bidders. If a company or university sends me an unsolicited proposal I am forced to take their original thoughts and ask for others to bid on conducting the research. We have the alternative route of the Geothermal Technology Organization. This organization of geothermal companies may solicit and fund research in whatever way it wishes, and DOE provides up to 50 percent of the funding. Since the Department of Energy owns the national laboratories, it is very easy to fund a lab to conduct research.

There is pressure from within DOE for research funding to be sent in large amounts to a single national laboratory. The Energy Research Advisory Board sees this method as

Second of all, I would like to thank DOE, LBL, and particularly Marcelo Lippmann, for giving us the opportunity to get this input to the programs and I hope that DOE will take some of our suggestions.

APPENDICES

APPENDIX 1

COMPILATION OF MAIN RECOMMENDATIONS MADE DURING THE MEETING

[Prepared by Marcelo Lippmann (LBL)]

General recommendation

The overriding objectives of the DOE geothermal research should be directed toward reducing the near-term development and operating costs, and developing methodologies that will help optimize and extend the lifetime of producing hydrothermal reservoirs.

Specific recommendations (listed in no particular order)

* Perform multidisciplinary field case studies
* Further develop modeling capabilities that couple chemistry and reservoir engineering simulations
* Continue fracture characterization research and field studies
* Carry out (geophysical, geochemical, and reservoir engineering) monitoring studies of producing fields
* Focus on cost-shared DOE/Industry projects
* Develop stable, cheap tracers for geothermal applications
* Perform injection studies (e.g., study the physical and chemical effects around injection wells)
* Carry out basic research on reservoir physics to determine/quantify fundamental parameters that control the behavior of geothermal systems and wells (e.g., relative permeability, adsorption, dispersion, etc.)
* Develop a better understanding of geothermal reservoir processes on the basis of theoretical, field and laboratory studies
* Improve data gathering and interpretation methodologies used in testing geothermal wells, in particular focus on fracture characteristics and multi-phase conditions
* Develop more reliable and cheaper downhole instrumentation

* Perform well monitoring studies that include detailed data on the changes of chemical and physical parameters
* Continue the research on scaling and corrosion in geothermal wells (e.g., metal sulphide scaling, HCl corrosion effects)
* Evaluate/compare the different computer programs available to model the geochemistry of geothermal systems for its predictive qualities and "user friendliness" (i.e., are the simpler models adequate for industry needs?)
* Support the modification of some of the existing (reservoir engineering and geochemical) computer model to make them more "user friendly"
* Analyze downhole temperature data to determine the effects of multiple feed zones, and compare wellbore and reservoir temperature distributions
* Develop basic thermodynamic data for geochemical reactions
* Study source mechanisms of microseismic events in geothermal systems
* Consider the development of expert systems applicable to geothermal systems (e.g., in exploration, welltest analysis)
* Study the natural setting of geothermal systems (i.e., geologic and hydrologic setting, fracture control)
* Investigate by drilling and associated science the "deep roots" of geothermal systems (i.e., what is the bottom of a hydrothermal reservoir ?)

APPENDIX 2

LIST OF ATTENDEES

Jeffrey W. Adams
State Lands Commission
245 West Broadway, Suite 425
Long Beach, CA 90802
(213) 590-5201

Michael C. Adams
University Utah Research Inst.
Earth Science Laboratory
391 Chipeta Way, Suite C
Salt Lake City, UT 84108
(801) 524-3435

M. Lee Allison
Earth Science Lab.
University Utah Research Inst.
Earth Science Laboratory
391 Chipeta Way, Suite C
Salt Lake City, UT 84108
(801) 524-3423

Michael S. Angel
L-524
Lawrence Livermore National Lab
Livermore, CA 94550
(415) 423-0375

Elwood Baldwin
California Energy Company
P. O. Box 1420
Inyokern, CA 93527
(619) 764-2551

Judith M. Ballantyne
University Utah Research Inst.
Earth Science Laboratory
391 Chipeta Way, Suite C
Salt Lake City, UT 84108
(801) 524-3425

Thomas R. Bandy
Pro-Technics International, Inc.
14760 Memorial Drive, #206
Houston, TX 77079
(713) 496-3734

Craig Beasley
University Utah Research Inst.
Earth Science Laboratory
391 Chipeta Way, Suite C
Salt Lake City, UT 84108
(801) 524-3422

Sally Benson
Earth Sciences Div., 50E
Lawrence Berkeley Laboratory
1 Cyclotron Road
Berkeley, CA 94720
(415) 486-5875

Gudmundur Bodvarsson
Earth Sciences Div., 50E
Lawrence Berkeley Laboratory
1 Cyclotron Road
Berkeley, CA 94720
(415) 486-4789

W. T. (Tom) Box, Jr.
Geysers Geothermal Company
P. O. Box 11279
Santa Rosa, CA 95406
(707) 578-2724

Robert A. Briffett
Department of Water & Power
P. O. Box 111, Room 1141
Los Angeles, CA 90051
(213) 481-7778

Dana Brock
Herzog Associates
3000 Cleveland Ave., Suite 200
Santa Rosa, CA 95403
(707) 523-3880

Randall W. Chang
U.S. Department of Energy
1333 Broadway
Oakland, CA 94612
(415) 273-7947

Tom Clemo
Idaho National Engineering Laboratory
P. O. Box 1625
Idaho Falls, ID 83415

Jim B. Combs
Geothermal Resources Intl. Inc.
1825 South Grant Street, Suite 900
San Mateo, CA 94402
(415) 349-3232

John Counsil
1148 Shady Oak Place
Santa Rosa, CA 95404
(707) 538-2288

William L. D'Olier
Geothermal Industry Consultant
P. O. Box 1657
Santa Rosa, CA 95402
(707) 584-7549

Bob Daniel
Unocal Geothermal Division
P. O. Box 6854
3576 Unocal Place
Santa Rosa, CA 95406
(707) 545-7600

William L. Desormier
Oxbow Geothermal
200 So. Virginia Street, Ste. 450
Reno, NV 89501
(702) 322-1300

Andy Drenick
GEO Operator Corporation
1330 North Dutton Ave., Ste A
Santa Rosa, CA 95401
(707) 523-4272

Leonard E. Duda
Sandia National Laboratories
P.O. Box 5800
Albuquerque, NM 87185-5800
(505) 844-2377

Melville C. Erskine, Jr.
5413 Silva Avenue
El Cerrito, CA 94530
(415) 234-6214

Sabodh K. Garg
S-CUBED
3398 Carmel Mountain Road
San Diego, CA 92121-1095
(619) 453-0060, ext.438

Norman Goldstein
Earth Sciences Div., 50E
Lawrence Berkeley Laboratory
1 Cyclotron Road
Berkeley, CA 94720
(415) 486-5961

L. Eric Greenwade
M/S 2212
Idaho National Engineering Laboratory
P. O. Box 1625
Idaho Falls, ID 83415
(208) 526-1276

Paul N. Hirtz
Thermochem, Inc.
5347 Skyland Blvd.
Santa Rosa, CA 95403
(707) 575-1310

Roland Horne
Petroleum Engr. Dept.
Stanford University
Stanford, CA 94305
(415) 723-9595

Jeffrey Hulen
University Utah Research Inst.
Earth Science Laboratory
391 Chipeta Way, Suite C
Salt Lake City, UT 84108
(801) 524-3422

Joe L. Iovenitti
2337 Panoramic Drive
Concord, CA 94520
(415) 798-8449

Younes Jalali
Petroleum Engr. Dept.
Stanford University
Stanford, CA 94305
(415) 723-9476

Elizabeth A. Johnson
State of Calif. Div. of Oil & Gas
50 D Street, Room 300
Santa Rosa, CA 95404
(707) 576-2385

Stuart Johnson
Chevron Resources
P. O. Box 5049
San Ramon, CA 94583
(415) 842-5321

Paul Kasameyer
Earth Sciences Div., L-205
Lawrence Livermore National Lab
Livermore, CA 94550
(415) 422-6487

Brian A. Koenig
Unocal Geothermal Division
P. O. Box 6854
3576 Unocal Place
Santa Rosa, CA 95406
(707) 545-7600

Robert L. Kohlbush
U.S. Dept. of the Interior
800 Truxtun Avenue, Room 311
Bakersfield, CA 93301
(805) 861-4012

Mark K. Kumataka
Santa Fe Geothermal, Inc.
P. O. Box 1009
Middletown, CA 95461
(707) 987-2335

Douglas Labrecque
University Utah Research Inst.
Earth Science Laboratory
391 Chipeta Way, Suite C
Salt Lake City, UT 84108
(801) 524-3422

Peter Ledingham
Geoscience Limited
The Falmouth Business Park
Bickland Water Road
Falmouth, Cornwall TR11 4SZ England
011-44-326-211070

Marcelo Lippmann
Earth Sciences Div., 50E
Lawrence Berkeley Laboratory
1 Cyclotron Road
Berkeley, CA 94720
(415) 486-5035

James W. Lovekin
California Energy Company
P. O. Box 1420
Inyokern, CA 93527
(619) 764-2551

Larry Lynnworth
Panametrics
221 Crescent Street
Waltham, MA 02254
(617) 899-2719

Ernest Majer
Earth Sciences Div., 50E
Lawrence Berkeley Laboratory
1 Cyclotron Road
Berkeley, CA 94720
(415) 486-6709

Tsvi Meidav
Trans-Pacific Geothermal
1330 Broadway, Suite 1525
Oakland, CA 94612
(415) 763-7812

Donald E. Michels
Don Michels Associates
P. O. Box 895
Whittier, CA 90608
(213) 698-5728

John D. Miller
Idaho National Engineering Laboratory
P. O. Box 1625
Idaho Falls, ID 83415
(208) 526-0881

Philip G. Mogen
Unocal Geothermal Division
P. O. Box 6854
3576 Unocal Place
Santa Rosa, CA 95406
(707) 545-7600

Joseph N. Moore
University Utah Research Inst.
Earth Science Laboratory
391 Chipeta Way, Suite C
Salt Lake City, UT 84108
(801) 524-3428

Dennis L. Nielson
University Utah Research Inst.
Earth Science Laboratory
391 Chipeta Way, Suite C
Salt Lake City, UT 84108
(801) 524-3438

John W. Pritchett
S-CUBED
3398 Carmel Mountain Road
San Diego, CA 92121-1095
(619) 453-0060, ext 440

Karsten Pruess
Earth Sciences Div., 50E
Lawrence Berkeley Laboratory
1 Cyclotron Road
Berkeley, CA 94720
(415) 486-6732

Marshall J. Reed
U.S. Department of Energy-CE342
Geothermal Technology Div.
Washington, DC 20585
(202) 586-8076

Joel Renner
Idaho National Engineering Laboratory
P. O. Box 1625
Idaho Falls, ID 83415
(208) 526-9824

Jill Robinson-Haizlip
Geothermal Resources Intl. Inc.
1825 South Grant Street, Suite 900
San Mateo, CA 94402
(415) 349-3232

Ronald C. Schroeder
Berkeley Group Inc.
1330 Broadway, Suite 1450
Oakland, CA 94612
(415) 465-1744

David A. Shirley
Lawrence Berkeley Laboratory
1 Cyclotron Road
Berkeley, CA 94720
(415) 486-5111

Susan G. Stiger
Idaho National Engineering Laboratory
P. O. Box 1625
Idaho Falls, ID 83415
(208) 526-0457

John Stodt
University Utah Research Inst.
Earth Science Laboratory
391 Chipeta Way, Suite C
Salt Lake City, UT 84108
(801) 524-3422

Charles Swift
Chevron Resources
P. O. Box 5049
San Ramon, CA 94583
(415) 842-5390

J. Lawrence Taylor, III
Pro-Technics International, Inc.
14760 Memorial Drive, #206
Houston, TX 77079
(713) 496-3734

Richard Thomas
California Div. Oil and Gas
1416 - 9th St., Room 1310
Sacramento, CA 95814
(916) 323-1788

Wilbur M. Thompson
State Lands Commission
245 West Broadway, Suite 425
Long Beach, CA 90802
(213) 590-5201

Alan C. Tripp
Earth Science Lab.
University Utah Research Inst.
Earth Science Laboratory
391 Chipeta Way, Suite C
Salt Lake City, UT 84108
(801) 524-3431

Alfred Truesdell
U.S. Geological Survey
345 Middlefield Road, M/S 910
Menlo Park, CA 94025
(415) 329-5212

Ed VanEeckhout
MS-D446
Los Alamos National Laboratory
P. O. Box 1663
Los Alamos, NM 87545
(505) 667-1916

Mark A. Walters
GEO Operator Corporation
1330 North Dutton Ave., Ste A
Santa Rosa, CA 95401
(707) 523-4272

Philip E. Wannamaker
University Utah Research Inst.
Earth Science Laboratory
391 Chipeta Way, Suite C
Salt Lake City, UT 84108
(801) 524-3445

John H. Weare
Dept. of Chemistry
3258 Urey Hall B-014
University of California, San Diego
La Jolla, CA 92093
(505) 844-2155

Phillip M. Wright
University Utah Research Inst.
Earth Science Laboratory
391 Chipeta Way, Suite C
Salt Lake City, UT 84108
(801) 524-3439

John P. Ziagos
Geothermal Resources Intl. Inc.
1825 South Grant Street, Suite 900
San Mateo, CA 94402
(415) 349-3232

LAWRENCE BERKELEY LABORATORY
TECHNICAL INFORMATION DEPARTMENT
UNIVERSITY OF CALIFORNIA
BERKELEY, CALIFORNIA 94720