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**PEER REVIEW
OF THE HOT DRY ROCK PROJECT
AT FENTON HILL, NEW MEXICO**

for

**The United States Department of Energy
Washington, DC**

via

**Princeton Economic Research, Inc.
Rockville, MD**

by

**GeothermEx, Inc.
Richmond, CA**

DECEMBER 1998

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EXECUTIVE SUMMARY

GeothermEx, Inc. (GeothermEx) is a subcontractor to Princeton Economic Research, Inc. (PERI) for the U.S. Department of Energy Hot Dry Rock Management program (contract number DE-AM07-97ID13517). This contract calls for a "Peer Review" of the Fenton Hill Hot Dry Rock project that was undertaken by Los Alamos National Laboratory (LANL) from about 1971 through 1995. The purpose of the Peer Review is to identify the primary lessons learned and techniques developed during the course of the Fenton Hill project, and to summarize the extent to which these technologies have been transferred to the U.S. geothermal industry.

Phase I of the Fenton Hill project lasted through 1980 and included drilling, fracturing and testing the Phase I reservoir. Phase II, which overlapped the end of Phase I, comprised drilling, fracturing and testing the deeper Phase II reservoir. For both Phase I and Phase II the Peer Review includes:

- a brief description of the project history and a review of the drilling, completion and hydraulic fracturing operations undertaken to create the reservoirs;
- a description of the flow and tracer tests and a summary of the more important results therefrom;
- information on downhole tool development and logging techniques;
- a description of seismic techniques used to map the reservoir; and
- a summary of reservoir modeling efforts, including code development.

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After the Hot Dry Rock (HDR) reservoir concept was developed in 1971, a project area west of the Valles Caldera area in New Mexico was selected on the basis of favorable geology and subsurface temperatures measured in shallow temperature gradient wells. In 1972, a test well (GT-1) was drilled to a depth of 2,575 feet in Barley Canyon, about 1-1/2 miles north of the Fenton Hill Site. Successful hydraulic fracturing experiments in the granitic basement rock in this well encouraged the project team to proceed further at Fenton Hill, where well GT-2 was drilled to a depth of 9,619 feet during 1974, and well EE-1 was drilled to a depth 10,053 feet during 1975. Numerous fracturing operations were undertaken in these wells, creating large, near-vertical fractures and smaller fractures of varying orientations, and a weak connection between the wells was developed. To improve the connection, GT-2 was redrilled twice. The second redrill, GT-2B, completed in 1977 at a depth of 8,907 feet, succeeded in intercepting a fracture or series of fractures connecting to a major, near-vertical fracture that intercepted EE-1, thus forming the Phase I "First Reservoir."

On
Oct,
1975.

There were several flow tests in 1977 and 1978 (referred to as Run Segments 1, 2 and 3) with injection into EE-1 and production from GT-2B, after which EE-1 was again hydraulically fractured, further enlarging the reservoir and improving the connection between the wells. This created the Phase I "Second Reservoir," which was tested at various pressures in 1979 and 1980 during Run Segments 4 and 5. At the end of Run Segment 5, the "Stress Unlocking Experiment" was undertaken to facilitate readjustment of the reservoir rocks to previous cooling, by pressurizing the reservoir system without flow, then resuming flow to measure the results. Tracer tests, which yield important information about reservoir volume, were conducted during most of these flow tests.

Production wellhead temperature (WHT) fell rapidly during the tests of the smaller First Reservoir, but was relatively more stable when the Second Reservoir was tested during Run Segments 4 and 5. During Run Segment 2, flow impedance declined dramatically. This is attributed to thermal

2.
Yes

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contraction and continued pressurization from the injection well, which opened natural joints and therefore provided additional communication with the production well.

The rework and hydraulic fracturing of EE-1 after Run Segment 3 caused an increase in reservoir volume, but the impedance remained unchanged, implying that the benefit from the reservoir volume increase was offset by the longer and perhaps more tortuous flow path between the inlet and outlet of the reservoir. Nearly constant flow impedance during Run Segment 4 could be attributed to a relatively small amount of cooling and constant pressure conditions during the test. The growth of reservoir volume during Run Segment 5 is attributed to heat extraction and a consequent contraction of rock volume. Despite evidence for increases in heat-transfer area and reservoir volume during this Run Segment, no evidence of impedance change due to cooling was observed. After the Stress Unlocking Experiment, the flow rate through the system increased, compared to earlier tests undertaken at similar production and injection well pressures.

The important lessons learned in Phase I included conclusions that:

- fractures could be artificially created by hydraulically stimulating wells drilled in hot, deep intrusive rock;
- inflatable open-hole packers are not a reliable method of isolating a zone for hydraulic fracturing;
- fracturing out of a cemented liner with a "polished bore receptacle (PBR)" was more reliable;
- attempts to create fractures through perforations in a cemented liner were unsuccessful;

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- pressurization, hydraulic fracturing, and heat extraction and consequent thermal contraction all caused increases of the heat-transfer area;
- increases in reservoir volume occurred in response to both pressurization and heat extraction;
- the volume of the most direct paths through the system was about 80% of the total volume of the system;
- impedance was highest near the exit from the formation into the production well, particularly when operating at low back-pressures;
- the volume of the reservoir that was active in terms of heat transfer and fluid flow was a portion of a larger fracture system;
- there were no geochemical hazards or impediments;
- the chemical quality of the circulating fluid was fixed by the *in situ* pore-fluid chemistry and the rate of fluid displacement during production;
- seismic events observed during initial pressurization of the First Reservoir were clustered about a vertical plane whose strike remained remarkably constant, while continued pressurization and water-loss diffusion resulted in a general displacement of microseismic events in a more dispersed region extending more than 1,500 feet away from both the injection point and the initial locus of events;

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- seismic data suggested that the Second Reservoir was not planar, but highly jointed and multiply fractured, indicating a volumetric rather than an areal source of heat (this also observed in the deeper Phase II reservoir); and
- seismic data could be used to track the location(s) of reservoir heat-transfer, by locating the microearthquakes induced in the course of pressurizing the system to unlock the stress induced by cooling.

The technology developed and/or transferred during Phase I included:

- development and application of passive microseismic techniques in reservoir mapping;
- development of active seismic techniques (acoustic ranging and shear shadowing) to determine relative well locations and to identify the presence of fractures between the seismic source and the receiver;
- numerous downhole logging tools, as summarized in Chapter 5 of this report;
- development of computer codes to model heat-transfer;
- development of LANL's numerical simulator FEHM, which incorporates fluid flow and heat transfer in fractures, permeation into the adjacent rock, and the distribution of stress in the reservoir;

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- modification of the "Muskat" technique (an old technique developed in the petroleum industry) for evaluating pressure transient data to determine separate impedances for the reservoir entrance, exit, and fracture system;
- development of analytical models to evaluate reservoir chemistry trends; and
- techniques for analyzing and modeling tracer recovery trends to determine reservoir volume and residence time.

Many of these techniques continue to be used in HDR development overseas, and some of the tracer techniques have been adapted for use in evaluating hydrothermal reservoirs.

Drilling of the two Phase II wells started in early 1979, while the Phase I reservoir was still being tested. The wells were designed to demonstrate the concept that a series of upward-extending vertical fractures would be created by hydraulically fracturing the deeper injection well, EE-2, and that these fractures would intercept the shallower production well (EE-3). Accordingly, the wells were directionally drilled along nearly parallel courses, from adjacent surface locations with about one thousand feet of vertical separation between the deeper, deviated sections. Each well took more than 400 days each to drill, reaching total depths of 15,289 feet (EE-2) and 13,933 feet (EE-3). Delays were associated with circulating cuttings from the hole when drilling with water, controlling hole direction, curing lost circulation, repairing casing damage and fishing out stuck drill pipe.

Long sections of hole were left open at the bottom of each well, to be fractured later. In well EE-2, the open-hole section extended from 11,576 feet to TD (total depth), and in well EE-3, the open-hole section extended from 10,374 feet to TD. In the initial Phase II fracturing operations, zone

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isolation using open-hole packers was tried again, with poor results; the packers failed to hold a seal, even when "backside" pressure was imposed to reduce the differential pressure across the packer. Therefore, using techniques similar to those used in high-pressure gas well completions, liners were cemented into the holes, and fracturing operations were undertaken using more reliable casing packers and a polished bore receptacle (PBR) to seat the fracturing string.

Following several smaller fracturing jobs that failed to connect the two Phase II wells, it was recognized that the fracture system could be extended by injecting greater volumes of water. Massive Hydraulic Fracturing (MHF) operations were then undertaken in EE-2 (December, 1983), during which more than 5 million gallons of water were injected; still, no connection was made. Furthermore, the casing in EE-2 was damaged because of an operational error that followed the failure of a component in the fracturing system. An MHF operation was then undertaken in EE-3 (May, 1984). Although this created a large fracture system, no connection was achieved between the wells so, during December 1984 through June 1985, EE-3 was re-drilled as EE-3A to intercept the zones of seismicity observed during the MHF of EE-2. This succeeded in making a connection, and a 30-day flow test of the system (the Initial Closed-Loop Flow Test, or ICFT) was conducted in May and June of 1986, with injection into EE-3A and production from EE-2.

Throughout the ICFT, production temperatures increased to final values of 192°C (at the production wellhead) and 232°C (downhole near the main fluid entries). The production rate also increased (to 200 gpm at the end of the test) as impedance decreased. Tracer data indicated the presence of a reservoir about twice as large as the Phase I reservoir. Tracer recoveries were lower, indicating a greater water loss than in the Phase I reservoir, and the Phase II volume of the most direct paths through the reservoir equaled only about 30% of the total reservoir volume, compared to 80% in the Phase I reservoir. The fluid chemistry was clearly different, with about two to three times the dissolved solids and higher dissolved gas concentrations than observed during Phase I.

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Improvements in seismic data collection had been made prior to the MHF of EE-2. A network of several downhole seismometers was installed, compared to only one (or occasionally two) used previously. This enabled more accurate determination of hypocentral locations, and permitted certain other interpretations to be made.

Seismic data collected during the ICFT indicated that only the southern half (injection end) of the volume defined by the massive hydraulic fracturing (MHF) operations undertaken in 1983 and 1984 was seismically active, and that seismicity occurred only after there had been enough injection to "fill" the southern volume. The seismic inactivity of the northern half suggested that this region was shielded by the pressure sink around the production well.

Two unsuccessful attempts were then made to repair the damage in EE-2. The well was eventually re-drilled as EE-2A (completed November, 1987) along a course parallel to the original hole, and a brief test of the system in December 1987 indicated little or no change from conditions during the ICFT. From October 1988 through December 1991, pressure was periodically maintained (by injection) and allowed to decline (by venting the wells), enabling certain storage-related parameters of the reservoir to be determined. Meanwhile, flow test surface facilities were being constructed and other preparations for the Long Term Flow Test (LTFT) were being made.

Flow tests resumed in December 1991 with four preliminary tests, followed in April 1992 by the start of what became the first phase of the LTFT. This ended after about 3-1/2 months with catastrophic failures of the main injection pumps. During this period, no thermal drawdown of the resource was observed, and tracer data showed that reservoir volume increased. To enable continued testing, a smaller injection pump already on site was put into service, and the Interim Flow Test (IFT) was conducted in August and September 1992; this lasted for six weeks and was terminated by another pump failure.

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A mud pump was then rented, and testing continued in December 1992 with two tests at higher production well back-pressure. The second phase of the LTFT began in February 1993 after an electric-powered centrifugal pump was rented for injection. Injection and production wellhead pressures were the same as during the first phase of the LTFT (3,960 and 1,400 psi, respectively). Production temperature was 184°C at the wellhead and 228°C downhole, each within one degree of the temperature observed during the first phase of the LTFT. However, water loss was lower at 7% (compared to 12% during the first phase) and the reservoir volume from tracer tests was 35% lower than indicated at the end of the first phase.

At the end of the second phase of the LTFT in April 1993, a pressure stimulation test was conducted. Similar to the Stress Unlocking Experiment undertaken in the Phase I reservoir, the purpose of this test was to determine if periodic shut-ins of the production well, conducted while maintaining injection, would rapidly boost reservoir pressure in the vicinity of the production wellbore, further dilating joints in that region, and leading to an increase in the flow rate upon re-opening the production well. Modest increases in energy production were realized, but the test was cut short by operational problems before a full evaluation of the potential gains could be made.

Further experimentation with this concept was undertaken during the cyclic flow tests of May 1993. These tests became notable for an increase of production flow rate that included a large jump (from 156 to 231 gallons per minute) when the production back-pressure was reduced for the third time. Twelve days later the flow rate was still 35% higher than before the tests, so it appeared that a permanent change of reservoir flow characteristics had occurred. Production well log temperatures showed no decline at the production zones, but the wellhead temperature increased to 190.4°C as a result of the higher flow rate up the well (less cooling during flow).

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The Reservoir Verification Flow Tests (RVFT) of 1995 followed two years of shut-in, during which pressure on the reservoir was allowed to decay to 1,450 psi, then maintained at this level. Results from the first phase of the RVFT (at 1,400 psi back-pressure) showed a flow rate 17% higher than the stabilized flow at similar operating conditions before the sudden flow rate increase of the May 1993 cyclic flow tests. The second phase of the RVFT (2,200 psi back-pressure) again showed a flow rate increase of 17% compared to previous flow at the same back-pressure during December 1992. Water loss was about 15%, which was considerably lower than the 27% measured previously at the same pressure.

A load-following experiment was conducted in July 1995 to simulate peak and off-peak operation of the system. For four hours on each of six consecutive days, the production well back-pressure was reduced, increasing the production rate and (consequently) wellhead temperature. The sixth cycle yielded a peak flow rate of 147 gpm (which was higher than the injection rate) at a wellhead temperature of nearly 189°C. The off-peak (baseload) production rate was 130 gpm at nearly 183°C.

The results of the Phase II flow tests have not been fully analyzed. However, the main lessons learned thus far from the development of the Phase II reservoir developments are as follows.

- Well completion techniques similar to those used in high-temperature, high-pressure gas wells were successfully used at Fenton Hill, and fracturing was accomplished by pressurizing a zone below a cemented-in liner.
- Drilling with mud as the circulating fluid proved more effective in the Fenton Hill subsurface environment than drilling with either water or aerated fluid.

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- The presence of an appreciable amount of H_2S caused the fracturing strings to fail. This was resolved by obtaining fracturing strings of more suitable metallurgy and with better joint connections.
- Partial cement jobs were selected by LANL as the best way to handle high pressure thermal cycling between injection and production in the same well. Unless a strategy of reservoir development is used that requires stimulation of only the injection well, HDR wells must be appropriately designed and completed to withstand the full range of temperatures and pressures that will occur. This has implications for the selection and use of casing and cement, and many other aspects of well design and completion.
- Hydraulic fracturing of the Phase II reservoir created a network of many small fractures rather than several large, vertical fractures, as had originally been anticipated. These fractures propagated away from the well at an angle, sometimes downward. This led to the need to re-drill EE-3 as EE-3A, illustrating the now-preferred development procedure that has been referred to as "drill-frac-drill" (as opposed to "drill-drill-frac").
- It was realized that the fracture system could be extended by injecting greater volumes of water; this led to the Massive Hydraulic Fracturing operations.
- The Phase II reservoir system was comprised of natural, pre-existing joints that were opened and propped by fluid pressure. LANL's analysis of injection, pressure decay and circulation tests indicated that the Phase II reservoir comprises at least three separate sets of joints that have opening pressures of 2,175 psi, 3,250 psi and 3,990 psi, respectively. LANL believes that the joints that opened at the highest pressure were crucial to establishing the circulating system between injection and production.

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- The contemporary stress field dictates the conditions under which these joints (which formed under different stress conditions) will open upon pressurization, but it does not control the orientation of the fractures.
- Downhole temperature and tracer data both indicate that the flow through the reservoir, rather than becoming concentrated into a few potential direct flow paths, instead progressively shifted towards more indirect flow paths as the test proceeded.
- Some of the reservoir volume created during the MHFs was not available during testing because the production well (drilled prior to the MHFs) was not located where it could fully tap the fractures that had been created. Therefore, the potential benefits of the MHFs were not fully realized. Water losses, which ranged from 5 to nearly 30% of the amount injected, may have occurred in this inaccessible area. It was estimated that an additional production well drilled in this area would increase the heat produced by a factor of about 3.
- A connection may have been made from the Phase II reservoir to the Phase I reservoir, either via leakage up the annulus of the injection well, or perhaps by extension of the fractures created in Phase II. This has not been verified.
- The improvements made in seismic data collection were well worth the effort. With the downhole seismic network, events could be located more accurately, and additional analyses of events, which led to better understanding of the reservoir and its connections to the wells, were made possible by improvements in data collection and storage.
- Alternative HDR production modes, such as cyclic production, may help to reduce reservoir impedance and optimize reservoir productivity.

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The technology developed and/or transferred as a result of the Phase II development includes:

- further improvements to downhole tools, particularly geophones;
- development of high-temperature cementing practices in collaboration with service companies, which contributed to improvements in the completion of deep, high-temperature gas wells;
- design and use of a new packer system to enable successful deployment and operation of hydraulic fracturing;
- development and bench-testing of prototype expandable metal packers that could also be used for this type of work;
- development of a wellbore heat-transfer computer code to: 1) estimate the rate and duration of water circulation required to cool the well prior to cementing operations; 2) estimate the amount of water needed to displace the cement; and 3) support other drilling activities;
- some of the zone isolation and completion methods used for hydraulic fracturing operations (see above), which may be useful to future developers of EGS;
- the application of seismological analysis techniques developed at Fenton Hill in other HDR investigations and in oil and gas and hydrothermal development projects;

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- the improvements to and use of LANL's numerical simulator FEHM, in HDR, hydrothermal and waste isolation studies;

- the development and use of GEOCRACK (a finite-element modeling program for geothermal reservoirs that fully couples rock mechanics, fluid flow and heat transfer) in HDR studies.

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1. INTRODUCTION

1.1 Purpose and Scope

GeothermEx, Inc. (GeothermEx) is a subcontractor to Princeton Economic Research, Inc. (PERI) on the U.S. Department of Energy's Hot Dry Rock Management program (contract number DE-AM07-97ID13517). The contract specifically calls for a "Peer Review" of the Fenton Hill Hot Dry Rock project undertaken by Los Alamos National Laboratory (LANL) and its predecessor Los Alamos Scientific Laboratory (LASL). For simplicity, we refer herein only to LANL, although some of the work was in fact undertaken by LASL.

As the budget for this work was approximately three man-months of effort, it is not intended to be a comprehensive review of the Fenton Hill program, which spanned more than 20 years and cost more than \$150 million. Such a review would require a considerably greater level of effort; Furthermore, Grant Heiken at LANL is presently preparing such a detailed review. The purpose of the report is to identify the primary lessons learned and techniques developed during the course of the Fenton Hill project, and to summarize the degree to which these technologies have been transferred to the U.S. geothermal industry.

To undertake the work, GeothermEx began with a review of numerous Fenton Hill reports and publications to become familiar with the project. Subsequently, a visit was made to Los Alamos to interview as many people as possible who had been involved with the project. Some of these people remain at LANL and others have retired. The people interviewed and their involvement with the project are listed in table 1.1. During the interviews, each person was asked to:

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- describe his or her involvement with the Fenton Hill project;
- describe what techniques worked and what didn't in his or her particular area of expertise;
- describe the methods, techniques or tools developed to overcome technical problems;
- comment on how these methods, techniques or tools were transferred to industry;
- describe what methods he or she would use if another Hot Dry Rock program were underway today; and
- provide a list and/or copies of the documents or reports which he or she considered to be most relevant to the Fenton Hill program, in his or her area of expertise or others.

Everyone interviewed was extremely cooperative and informative, both during the interviews and during follow-up phone calls and requests. Access to reports and other documents was provided, and numerous documents were photocopied during the visit. GeothermEx gratefully acknowledges the helpful attitude of present and former LANL staff members towards this work.

1.2 Structure of the Report

This report begins with a very brief history of the Fenton Hill project to provide a context for what follows. The next sections of the report are structured according to the logical progression of the project: well drilling, well completion and reservoir creation by hydraulic fracturing; flow and tracer testing; and reservoir assessment. Each of these sections includes summaries of operations, techniques or methods developed, and the nature and extent of technology transfer.

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Considering the limited budget for this work, it was not possible to evaluate every aspect of the work undertaken at Fenton Hill. For example, we have provided only a brief description of the surface equipment used for flow testing, very little about laboratory tests undertaken on Fenton Hill rock samples, and nothing is included herein on the economic feasibility studies that were undertaken on the basis of the Fenton Hill test results. Instead, we concentrated on the technical aspects of the resource itself and the major accomplishments made.

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2. PROJECT HISTORY

2.1 The Concept

The concept of producing energy from Hot Dry Rock (HDR) came to light in 1970 as a result of rock fracturing experiments associated with the development of a "Nuclear Subterrene," or rock-melting penetrator. In developing the penetrator concept, it was recognized that while natural porosity and permeability would decrease with depth, temperatures would increase; therefore, the natural heat energy of the earth at drillable depths was significant.

In deep, low permeability zones, fractures would be needed to provide space for the melted rock, and artificial fracturing techniques were being developed by the petroleum industry at that time. The onset of the pending energy crisis and the recognition of the significant heat in the earth's crust prompted LANL to recognize that if artificial fractures could be created in areas of high heat flow, the earth's heat could be recovered by circulating water through these artificial fractures, and the concept of Hot Dry Rock was proposed (Robinson *et al.*, 1971), then further developed and patented.

2.2 The Site

Valles Caldera was the site chosen to test the concept of creating a geothermal reservoir in hot dry rock. Conveniently located close to LANL (figure 2.1), this area had the advantage of relatively high heat flow and recent volcanism. The geology of the area was well understood owing to previous exploratory drilling for oil and geothermal resources, and hot springs were known to exist. Soon after the LANL group began its search for an HDR site, Union Oil Company (now Unocal) and Baca Land and Cattle began further drilling and exploration for geothermal resources within the caldera. Other sites were considered in these early days of the project, but as funding

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was uncertain, LANL was predisposed to a site nearby the lab, and began drilling temperature gradient holes in late 1971.

2.3 Gradient Hole Drilling

Between December 1971 and July 1972, LANL drilled 10 shallow (≤ 100 feet in depth) temperature gradient holes (referred to as sites 1 - 10) and four intermediate (500 - 750 feet in depth) temperature gradient holes (referred to as sites A - D). Gradient hole locations are shown in figure 2.2.

The initial series of 10 holes were drilled around the Valles Caldera. Some were located in the Fenton Hill area (four holes: 2, 8, 9 and 10), another about 5 miles to the north (hole 1), another about 6 miles to the SE on the south side of Valles Caldera (hole 3), and others on the east side of the caldera, about 10 miles east of Fenton Hill (four holes: 4, 5, 6 and 7). Completed in recent volcanic rocks, seven of these were deep enough to penetrate the shallow water table, and temperature gradients ranging from $84^{\circ}\text{C}/\text{km}$ to as high as $235^{\circ}\text{C}/\text{km}$ were measured in the deepest parts of these holes, with the highest gradients measured in wells closest to Fenton Hill.

The four deeper wells (A, B, C and D; see figure 2.2) were drilled in the spring of 1972, and these penetrated through the young volcanics and into the underlying Paleozoic sedimentary rock. All were located on the west side of the Valles Caldera, where the highest gradients had been measured in the shallower holes. Designed to help pick the best site for the first deep exploration well, temperature gradients in these four intermediate depth wells were on the order of 100 to 150°C , and fairly similar from well to well.

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2.4 Exploration Well GT-1

The first deep exploration well, GT-1, was drilled to: 1) sample the geologic section down to the planned total depth of 3,000 feet; 2) measure deep temperature gradients; 3) recover samples of the granitic basement rock for testing; 4) determine the *in-situ* permeability of the basement rock; 5) determine the pressure that would be required to induce hydraulic fracturing; 6) determine the orientation and other characteristics of hydraulic fractures; and 7) investigate drilling conditions. Because this is the only place in this report where GT-1 is mentioned, we provide more details on the drilling, completion and testing of this well than is provided for the other wells discussed in this section of the report. The details of operations pertaining to the other Fenton Hill wells are presented in subsequent chapters.

A site was selected in Barley Canyon on the basis of favorable temperature gradients from the shallow and intermediate holes, access, terrain, and permitting constraints. It has also been inferred that the location in the canyon would save the costs associated with drilling through the upper part of the geologic section, thus reaching basement at a shallower drilled depth than in a well spudded from a higher surface elevation. Furthermore, the location was outside margin of the Valles Caldera (figure 2.1) and devoid of any mapped faults, which were thought to be possible sources of permeability and therefore to be avoided for a true HDR well.

Well GT-1 was spudded on 9 May 1972, and penetrated 160 feet of young volcanics, Paleozoic sediments to 2,105 feet and pre-Cambrian gneiss and granite (crystalline basement rock) to the total depth (TD) of 2,575 feet, which was reached on 30 June 1972. The well had 5-inch diameter casing to 2,400 feet, and was open (uncased) from 2,400 feet to TD. Stable bottomhole temperature was reported to be approximately 100°C. The well was drilled with air as the

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circulating fluid throughout most of its depth. This caused some delays, primarily resulting from stuck drill pipe.

Several hydraulic fracturing experiments were undertaken in well GT-1 in 1973 (Aamodt, 1977). Initially, eight specific 6-foot-long intervals at depths ranging from 2,429 to 2,547 feet were isolated with open-hole packers and fractured at pressures ranging from 2,200 to more than 2,700 psi using a few gallons of water. In one of these intervals, the breakdown pressure was reported to be greater than 3,300 psi. The fractures were then extended in each zone by pumping a greater volume of water at slightly lower pressures (2,000 to 2,300 psi). At one interval, a larger volume of water (a few thousand gallons) was used to create and extend the fracture. Envisaging the hydraulic fractures as penny-shaped cracks, the radius and volume of the fractures were calculated, as was the magnitude of the least principal stress. The open-hole packers leaked in nearly all fracturing jobs; despite this, sufficient pressures were applied to break down the rock.

Later, a geophone was installed downhole in GT-1 to monitor the seismicity associated with hydraulic fracturing experiments in other wells.

2.5 The Phase I System

After completing well GT-1, LANL moved its operations to the Fenton Hill site, about 1-1/2 miles south of Barley Canyon. This site was chosen as it was adjacent to a paved road, electrical and telephone lines. Furthermore, it had been burned in a forest fire a year or two earlier and was thus devoid of trees. LANL planned to drill a second exploratory well (GT-2) and then drill two more wells (EE-1 and EE-2) to form a production - injection loop. However, management decided not to drill three wells in this phase of the project, and at its completion, the Phase I loop consisted of

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GT-2B (the second redrill of GT-2) and EE-1. Details of the drilling of these wells are included in the following chapter, but a summary of operations is provided here.

Well GT-2 was spudded on 17 February 1974, and completed at a depth of 9,619 feet on 20 December 1974. A maximum temperature of 197°C was measured at about 9,600 feet. Fractures were created in several intervals in the well, and various techniques were tried for isolating the zone to be fractured, including (primarily) open-hole straddle packers, casing packers and fracturing through perforations in cemented casing. A major fracture was created about 20 feet from the bottom of the well, and despite numerous attempts to stimulate other zones in the well and connect them to the deeper fracture, these were not successful.

Meanwhile, work was done on improving the geophone array to enable it to be deployed downhole and therefore endure high temperatures, and seismic signals were recorded during several of the fracture initiation and extension experiments conducted in well GT-2. For the first of only two times during the Fenton Hill project, fractures in GT-2 were propped by pumping sand down the well, which had the desired effect of reducing the resistance to flow, or impedance.

Well EE-1 was spudded on 26 May 1975 from a surface location about 250 feet north of well GT-1, and completed at a depth of 10,053 feet on 12 October 1975. The well was directionally drilled from 6,886 feet to intercept the fracture thought to extend vertically downward from the bottom of well GT-2. A connection was clearly made between a fracture created at about 9,600 feet in EE-1 and the fracture created in well GT-2; however, the impedance of the well pair was very high, and ways were sought to improve the connection. After a mineral leaching experiment by injection of a sodium carbonate solution failed to improve the situation, LANL decided to redrill well GT-2 to intersect the fracture created in EE-1.

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Starting in May 1977, GT-2A was side-tracked from GT-2 at a depth of 8,144 feet and drilled directionally to a total depth of 9,184 feet. A fracture connected to EE-1 was encountered at 8,645 feet; however, the impedance of this connection was still high, and it was concluded that well GT-2 should be redrilled again to intersect EE-1's fracture at a greater depth. GT-2B was kicked off at a depth of 8,270 feet, encountered the fracture zone from EE-1 at 8,767 feet, and was completed at a depth of 8,907 feet in July 1977.

The results of system impedance testing indicated that GT-2B had not penetrated the fracture created in EE-1, but instead was drilled into one or more smaller, natural fractures which had been re-opened during hydraulic fracturing operations.

Thereafter began a series of flow tests to evaluate the connection between the wells and the amount of heat that could be recovered from the man-made reservoir. A surface facility was constructed which consisted of injection pumps capable of delivering up to 300 gpm at pressures up to 1,450 psi into well EE-1, pressure controlling valves and production piping from the GT-2B wellhead, a strainer to remove particulate, fluid sampling ports, a data acquisition system, and a heat exchanger with fans to air-cool the producer water.

An initial test, referred to as Run Segment 1, was conducted for four days beginning in September 1977. In this and the remaining Phase I flow tests, EE-1 was the injection well and GT-2B was the production well. From January through April 1978, the second test (Run Segment 2) of the Phase I system was conducted. Fluid temperature above the uppermost fracture in the production well decreased during this 75-day test from 175° to 88°C and flow rates ranged from 125 to 150 gallons per minute (gpm). Impedance decreased and reservoir size apparently increased during the test. During the several months of shut-in before the next test, various logs were run, and the surface equipment was modified.

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Run Segment 3 went from 18 September to 27 October 1978, during which time the production well pressure was maintained at a relatively high level (1,400 psi) to decrease the impedance of the system and increase the heat transfer area. During this test, which is also referred to as the "high back-pressure experiment", leakage up the annulus of the injection well had increased to 20 gpm, which indicated a deterioration of the cement around the production casing of the well. Therefore, the decision was made to re-cement the casing before further testing; this was undertaken in January 1979.

After re-cementing EE-1, gas-fracturing was tried (without success). Then the well was hydraulically fractured, which opened a previously closed or sealed fracture which yielded a larger heat transfer area than had been previously available. Seismic signals associated with this event were received in well GT-2B and recorded, and the evolving image of the reservoir was modified on the basis of the newly created and seismically mapped fracture system.

Run Segments 4 and 5 of the Phase 1 loop were conducted in 1979 and 1980. The latter was a 286-day test followed by a "stress-unlocking experiment", during which both the production and injection wells were shut in and pressurized, followed by a flow test. Run Segment 5 was the longest Phase I test, and showed that the system could be produced with minimal temperature decline, manageable system impedance and relatively low water losses (about 10%). A binary generating unit was installed and successfully used to generate about 60 kW of power during brief periods of Run Segment 5.

2.6 The Phase II System

The first of the Phase II wells, EE-2, was spudded in April 1979. Directionally drilled from a depth of about 7,000 feet, well EE-2 was completed at a depth of 15,289 feet in May 1980. EE-2

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was intended to be the deeper, injection well of the Phase II well pair, and LANL expected to create a series of about 15 vertical fractures to connect EE-2 to EE-3. The development of an "interim" Phase II system consisting of three fractures was proposed, and this would use the existing Phase I surface facilities rather than the larger Phase II facilities, which were being designed.

EE-3 was spudded in May 1980 after the completion of EE-2, and reached a final depth of 13,933 feet in August 1981. Meanwhile, construction began on the surface facilities for Phase II. During FY 1982, the focus of work was on hydraulic fracturing in EE-2. After two unsuccessful attempts using inflatable open-hole packers, a fracture was initiated in the bottom of well EE-2 below a steel liner, which had been cemented in place about 500 feet off the bottom of the well. Seismic mapping revealed that the resulting fractures were not vertical but instead dipped about 40°, passing beneath the bottom of EE-3. Therefore, in hopes of connecting to EE-3, a shallower zone was fractured in EE-2, resulting in the creation of two inclined sub-parallel fractures extending downward from the wellbore. No connection was made at this time.

Attention then turned to EE-3. Between November 1982 and September 1983, hydraulic fracturing was concentrated in two intervals: 1) between the bottom of a cemented liner at 11,389 feet and the top of a sand plug at 11,770 feet; and 2) between the bottom of the casing shoe at 10,374 feet and the top of the cemented liner at 10,950 feet. In both zones, fractures were created, but still no connection was made between the two Phase II wells.

In December 1983, a Massive Hydraulic Fracturing (MHF) experiment was undertaken in well EE-2 using a new fracturing string. A total of 5.6 million gallons of water were injected over a period of 61 hours. Seismic data indicated that no connection had been made, and a "seismically quiet" zone seemed to exist around well EE-3. A MHF was then undertaken in EE-3, during which 2

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million gallons were injected below a cemented liner at 6,440 psi. This still did not produce a connection, and logging indicated that some of the injected fluid bypassed the targeted injection zone, flowed up the annulus (through a micro-annulus in the cement or through fractures around the cement) and exited the well in a permeable zone (first identified by circulation loss during drilling) near the casing shoe.

The decision was made to re-drill EE-3 to penetrate as much as as possible of the seismic cloud created around EE-2 during its MHF. This was undertaken from December 1984 through June 1985. Well EE-2 was kept pressurized during drilling, and a hydraulic connection was first noted when water began flowing into EE-3A while drilling at a depth of about 11,800 feet in May 1985. After drilling to 12,205 feet, this zone was hydraulically stimulated, improving the connection between the wells. Drilling continued to a depth of 13,182 feet, and three other zones were stimulated. Only the shallowest of these was connected to EE-2; at completion, therefore, EE-3A had several connected fractures in the two successfully stimulated zones.

In April and May of 1986, EE-3A was re-completed with a new 5-inch liner and 4-inch production tubing, and the Interim Closed-Loop Flow Test (ICFT) was conducted for 30 days in May and June 1986. A total of nearly 10 million gallons of water were injected into EE-3A at rates ranging from 150 - 300 gpm at wellhead pressures up to 4,400 psi. About 2/3 of this was recovered by production well EE-2, at rates ranging from 100 to 220 gpm, with a final wellhead temperature of 192°C. Another 20% of the injected water was recovered from storage upon venting the system after the end of the test.

It was determined during the ICFT that the cement behind the 9-5/8-inch casing in well EE-2 was deteriorating, and it was also known that the 7-inch liner inside the 9-5/8-inch casing was collapsed at 10,500 feet, preventing any logging of the actual production zone. Therefore, in FY

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1987, a repair was attempted, but because the 9-5/8-inch casing was also collapsed at 10,500 feet, LANL (on the recommendation of an industry committee) decided to plug the well back and re-drill it, following the original well course as closely as possible. Well EE-2A was completed in November 1987, although the 7-inch liner and production wellhead were not installed until the following year. The reservoir was tested before and after running the liner, indicating that a wells EE-2A and EE-3A were connected by a reservoir of similar volume to that connected by EE-2 and EE-3A. The wells were now available at then end of 1988 for a Long Term Flow Test (LTFT) of the Phase II reservoir, however, funding became a severe constraint around this time.

In FY 1989, equipment was designed and specified for the LTFT, including pumping equipment, a gas separator, heat exchangers, valves, piping, well master valves, and so on. A test was begun to determine the rate of reservoir leak-off at different reservoir pressures (Experiment 2077); this experiment continued through 1991. During FY 1990 and 1991, construction of the surface facilities for the LTFT were essentially completed.

During FY 1992, testing of the Phase II system got underway, starting with four preliminary tests from December 1991 through March 1992. During the first of these, conducted to test the surface facilities, 370,000 gallons of water were circulated through the reservoir, with a final production temperature of 154°C. This and the subsequent preliminary tests enabled a level of familiarity with the surface facilities and system operation to be achieved, and revealed some minor problems which were repaired prior to the start of the LTFT.

The LTFT commenced on 8 April 1992 and concluded on 31 July 1992. During this test, the injection rate in well EE-3A ranged from about 100 to 110 gpm at nearly 4,000 psi and the production from EE-2A ranged from about 85 to 100 gpm at about 1,400 psi, with a production temperature of about 360°F. When the primary injection pumps failed, the test was ended

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prematurely. Testing continued at lower rates and pressures from 20 August to 1 October 1992 using spare pumps; this is referred to as the Interim Flow Test (IFT). In December 1992, two brief tests at different back pressures were conducted.

After obtaining and installing new pumps, Phase 2 of the LTFT began in February 1993 and continued to April 1993, yielding similar results to the initial LTFT. At the end of the Phase 2 test, the production well was shut in several times and pressure was allowed to build in the system to try to increase the energy recovery from the system. In May 1993 the wells were shut in, and there was a two-year hiatus in operations because of lack of funds.

In late 1993, DOE issued a Notice of Program Interest to see if private industry or non-federal municipal institutions were interested in participating in an industry-led, government co-funded plan to develop market energy from an HDR site (presumably Fenton Hill, although the documents do not specifically say this). Responses were received from various organizations, 29 of which expressed interest. Willingness to spend their own money was expressed by 5 of the 29. Based on this response, a solicitation was issued by DOE (Albuquerque Operations Office) with the purpose of providing an incentive for private industry to construct and operate a facility to produce and market energy from an HDR resource. A total of \$1.5 million was to be made available in FY 1995 for this project.

In May 1995, testing began again, and a series of four tests (Phases 1 and 2 of a Reservoir Verification Flow Test or RVFT, a load following experiment and a final tracer test) were conducted through July 1995. During Phase 1 of the RVFT, conditions were very similar to those in the LTFT. In Phase 2 of the RVFT, the production well was back-pressured to about 2,200 psi and production rate decreased accordingly. During the load-following test, back pressure was reduced for four hours each day to represent a period of peak production. Finally, testing

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operations finished at Fenton Hill with a tracer test, in which two tracers were injected into the reservoir and final estimates of reservoir volume were obtained.

In October 1995, DOE withdrew the solicitation for the joint industry-DOE HDR development and announced that no award would be made. A plan to plug and abandon the Fenton Hill wells and restore the site was developed in late 1995 or early 1996, and all of the wells except EE-2A were abandoned in 1996 and 1997. Some buildings and one of the drilling sumps were left intact, and in July 1998, an interagency agreement was signed between DOE (Los Alamos Area Operations Office) and the U.S. Forest Service stating that the Fenton Hill site will now be used for various funded astronomy projects, owing to its high elevation and favorable meteorological conditions.

Data from the LTFT and other tests conducted from 1992 to 1995 have now been extracted from the data collection system and some analysis is anticipated, although most of the LANL personnel who worked on Fenton Hill have either left the lab or are working on other projects.

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3. DRILLING, COMPLETION AND RESERVOIR CREATION

3.1 Phase I

3.1.1 Well GT-2

The second HDR deep well was planned to be cased to 2,600 feet and drilled to a TD of 4,000 feet, where temperatures of 140°C were anticipated. LANL planned to develop a 1,000-foot long fracture extending out from the well, and made a preliminary design for a downhole, single-well heat recovery system. The Fenton Hill site was chosen for this well because it was adjacent to a paved road, electrical and telephone lines. Furthermore, a forest fire a year or two earlier had left the area devoid of trees.

Well GT-2 was spudded on 17 February 1974. It penetrated recent volcanic rocks to 450 feet, Paleozoic sediments to 2,404 feet, and pre-Cambrian basement rock to its total depth of (6,352 feet), reached on 13 July 1974. The well was completed with 10-3/4-inch casing cemented to a depth of 2,535 feet, and had a 9-5/8-inch (reported diameter; may actually be 9-7/8-inch) open hole to TD. The well was nearly vertical, with a maximum angle at depth of about 5° from vertical. There were several inflows of water from open fractures in the open interval, and core analysis showed a great number of old fractures which had been sealed by recrystallization and/or secondary mineralization.

GT-2 was drilled with mud as the circulating fluid to a depth of about 1,600 feet, with water to 1,889 feet, with air to 3,556 feet, with water to 3,728 feet, with air for an unspecified but short interval, and finally with water to its initial TD of 6,352 feet.

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While the well was being drilled, a six-station seismic network was set up around the Fenton Hill site. Each station was set up in a site excavated to a depth of 6 to 10 feet, in which a concrete slab was poured. Three seismometers were installed on the slab at each site. In addition, as mentioned above, a geophone was installed at a depth of 2,525 feet in well GT-1 in Barley Canyon, about 1-1/2 miles north of Fenton Hill.

Caliper and other logs were run in the open hole to determine which intervals were closest to "gauge" (*i.e.*, the diameter of the drill bit) and therefore likely to be the best places to set open hole packers. Other electric logs (including gamma, sonic, spectral gamma and dipmeter) were run to evaluate fractures and *in-situ* rock parameters, and numerous temperature, pressure and spinner (flowmeter) logs were run.

During August and September 1974, the first series of hydraulic fracturing experiments was undertaken in well GT-2. Six separate zones, ranging in length from 80 to about 300 feet, were isolated with open-hole packers and fractured. As in well GT-1, the packers often leaked and sometimes they failed altogether. However, several fractures were created and extended. The first set of fractures was created at 2,775 - 2,865 feet, at pressures similar to those found at similar depths in well GT-1. Seismic signals associated with these fracturing events were recorded. Fractures that were apparently aseismic were created in two depth intervals: 4,877 - 4,927 feet; and 5,314 - 5,394 feet. Seismic signals thought to be caused by fracture extension were noted when the upper of these two intervals was repressurized. LANL theorized that the lack of seismicity accompanying initial fracture creation indicated that pre-existing, weakly sealed (mineralized) fractures favorably oriented to the present-day stress field were being opened during hydraulic fracturing operations.

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When the supply of packers was exhausted, LANL decided in October 1974 to drill ahead while waiting for more packers to be delivered. The hole was deepened by nearly 350 feet to a new TD of 6,700 feet, where extrapolation of temperature surveys indicated a stable bottomhole temperature of 146°C. Considering the problems experienced with the open hole packers, a 210-foot length of 6-1/2-inch liner was cemented into the hole from 6,296 to 6,506 feet, and a "polished bore receptacle" (PBR), into which the tubing string used for hydraulic fracturing operations could be firmly seated without leaking, was installed at the top of the liner. Casing packers were used to seal off the lower part of the well for hydraulic fracturing.

Between the depths of 6,525 and 6,702 feet, two major, near-vertical fractures were created, extended and then propped by pumping sand down the well. Impedance (resistance to fluid flow, measured in gpm/psi) out of the fractures and into the wellbore was reduced by the use of sand to prop the fractures open. This was deduced because a greater volume of water (>90% of the injected fluid) was produced back upon venting the well after injecting sand and water, as compared to the production after injecting water alone (only 50 - 75% was produced back during venting). Like some of the others, the initial fracturing events at 6,525 - 6,702 feet were aseismic, but seismic signals thought to be associated with fracture extension were recorded later when this zone was re-pressurized.

The cemented liner was then perforated between 6,370 and 6,380 feet, and the perforated zone was isolated (using casing packers) and pressurized. The packers leaked and were removed; thereafter, a single casing packer was placed above the perforations and the well (both the perforated zone and the open hole below the liner) was pressurized. Although the available reports are ambiguous and contradictory, it appears that there was little to no indication of fracturing; neither seismicity nor pressure changes during fracturing operations are reported. In any case, it is difficult to understand how fractures could have been created in the perforated

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interval if the lower, previously fractured part of the well was open, since it is stated that the lower packer was removed prior to fracturing. However, several reports state that fractures were successfully made through the perforations. Subsequent testing by isolating portions of the well indicated that there was little or no connection between the perforated zone and the deeper fractures that had been created in the open hole.

Shortly thereafter, the cemented liner was removed from the well and the open hole was cleaned out with a 9-5/8-inch (reported diameter; may actually be 9-7/8-inch) bit. On 12 October 1974 deepening operations began again. A 9-5/8-inch (reported diameter; may actually be 9-7/8-inch) hole was drilled to 9,581 feet, and a 7-7/8-inch hole was drilled to 9,619 feet. Several cores were collected in these intervals. Numerous electric and temperature logs were run from 6,500 to 9,610 feet. A 7-5/8-inch liner with a PBR at its top was then cemented in place from 8,973 feet to 9,581 feet. After the cement had set, a casing packer was lowered into the liner. LANL had intended to set the packer near the bottom of the liner, but it set prematurely about halfway down at a depth of 9,212 feet and could not be moved. The drilling rig was released on 20 December 1974, and preparations began for hydraulic fracturing and other experiments in the deepened well, in which a maximum temperature of 197°C had been measured at about 9,600 feet.

Injection fall-off tests ~~were~~ revealed the well's low intrinsic permeability. Because of leakage around the packer, a fracture was unintentionally created in the uncased lower part of the well. This fracture was extended in a series of pressurizations, and seismicity was recorded in geophones deployed higher up in the wellbore.

Experiments in well GT-2 resumed in June 1975, after a workover rig had been moved in. The leaky packer was loosened and pushed to the bottom of the well. The liner was then perforated on 31 July 1975 at 9,250 and 9,350 feet, and a straddle packer was set to isolate the upper

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perforated zone. When pressurized, the formation broke down at 2,250 psi. A lack of pressure change below the lower packer indicated that there was no connection between this zone and the deeper fracture in the open hole. The straddle packer was then set across the perforated zone at 9,350 feet, where formation breakdown occurred at a pressure of 1,750 psi. Again, there was no indication that these fractures were connected with the others known to exist in the well.

Further perforations were then made at 9,150, 9,450 and 9,550 feet. The breakdown pressure at 9,150 feet was 1,750 psi, but neither of the other two perforated zones could be broken down at pressures up to 3,050 psi. These two intervals were then re-perforated. After that, the 9,450-foot zone was broken down at 3,250 psi, but the fracture closed and a later pressurization to 3,500 psi gave no indication of formation breakdown. Similar results were obtained for the perforated zone at 9,550 feet. Later these two zones were both isolated by a straddle packer assembly, and very high pressures (up to 5,000 psi) were required to break down the formation. The drilling rig was released on 1 October 1975.

3.1.2 Well EE-1

Well EE-1 was spudded on 26 May 1975 from a surface location about 250 feet north of well GT-1. Surficial volcanic rocks were drilled to 450 feet and Paleozoic sediments were drilled to 2,401 feet, where the top of the crystalline basement rock was reached. A 13-3/8-inch casing was set and cemented at a depth of 2,431 feet, and drilling proceeded with water using a 12-1/4-inch bit to a depth of 6,420 feet, where a 10-3/4-inch casing was set and cemented. Drilling resumed with a 9-7/8-inch bit to 6,886 feet, where a series of experiments were performed starting 23 August 1975.

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The seismic network was tested by detonating charges in well EE-1, recording signals at geophones placed downhole in well GT-2. After an initial pressurization to 1,200 psi which caused no apparent formation breakdown, an open-hole packer was set at 6,480 feet and the short open interval was pressurized. Formation breakdown occurred at 1,900 psi, and a fracture was created just below the packer.

Because of suspected leakage past the packer and the presence of natural fractures in the lower part of the hole, a cement plug was placed from 6,480 feet to TD. Then the well was pressurized again, and it is reported that fractures were created between 6,437 and 6,454 feet; however no seismic data were recorded during this fracturing job because the geophones in well GT-2 failed from prolonged exposure to high temperature. Subsequently, SP and IP logs were run in EE-1 and GT-2 under various pressure conditions, and were compared to similar logs run before the creation of the fractures at 6,437 to 6,454 and 6,480 feet in EE-1. Then an "acoustic ranging" experiment was undertaken, in which charges were detonated in EE-1 at 6,200, 6,400, 6,600 and 6,800 feet, and signals were recorded in GT-2.

Although LANL had planned during this phase of the project to drill two wells (EE-1 and EE-2) and connect them by hydraulic fracturing, the Fenton Hill project management was directed to abandon its plans to drill EE-2 and to connect EE-1 to GT-2 instead. The GT-2 fracture was thought to extend vertically downward from the bottom of the well at an uncertain azimuth. Therefore, LANL decided to drill well EE-1 in a course passing directly beneath the bottom of GT-2 at a depth of 9,800 feet (just less than 200 feet below the bottom of GT-2). A 2.75-foot long core was cut at the bottom of GT-2 to confirm the presence of the fracture. The lack of fractures in the recovered core was attributed to the fact that because the well was inclined about 5° to the vertical, the fracture must deviate away from the wellbore. Therefore, the plans for drilling EE-1 remained unchanged.

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Well EE-1 was then deviated by directionally drilling (using a mud motor) starting on 31 August 1975 from 6,886 feet to turn it to the desired course (toward GT-2). An "acoustic ranging" experiment, in which charges were detonated in well GT-2 and signals were recorded by geophones set at 9,000 - 9,100 feet in well EE-1, was made to calculate the horizontal distance between the two holes. Drilling in EE-1 continued to a depth of 9,575 feet, where another acoustic ranging experiment indicated that the wellbores were about 26 feet apart. However, the direction from which the signal generated by detonation in GT-2 arrived at the geophones in EE-1 could not be determined because an orienting camera in the geophone package failed. The experiment was repeated successfully, and it was determined that EE-1 was nearly due west of GT-2.

Then, while pumping water to inflate the GT-2 fracture and inducing an electric current in GT-1 at a depth of 9,535 feet, a log run in EE-1 showed an increase in induced potential, indicating that EE-1 was approaching the GT-2 fracture.

Drilling resumed in EE-1 to a depth of 9,877 feet. GT-2 was pressurized and downhole pressure was monitored, as it was anticipated that it would drop when EE-1 penetrated GT-2's fracture. While pressurizing GT-2, seismic signals were recorded in the geophone package in EE-1, and it was determined that the GT-2 fracture was oriented N27°W, had a lateral extent of about 500 feet, and was 30 to 60 feet away from EE-1.

Drilling of EE-1 continued to a total depth of 10,053 feet, reached on 12 October 1975. A packer was then set at 9,600 feet and GT-2 was pressurized to 2,100 psia by injecting at a rate of 170 gallons per minute (gpm). Upon reducing the injection rate to 9 gpm, pressure declined gradually in GT-2. Meanwhile, the open hole below the packer in EE-1 was pressurized to 2,400 psi. The pressure decline slowed and eventually stopped in GT-2. The hydraulic connection

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between the two wells was further demonstrated after EE-1's packer failed, and water flowed from EE-1 as long as injection was occurring in GT-2. Attempts were made to set packers deeper in order to fracture EE-1 below 9,650 feet, but these were not successful. Therefore, a string of production casing (8-5/8-inch from the surface to 8,600 feet; 7-5/8-inch to 9,599 feet) was run in the hole and cemented from 7,700 to 9,599 feet. This left about 450 feet of open hole with at least one hydraulically induced fracture at 9,650 feet which was connected to well GT-2 (later it was discovered that the fluid was exiting well EE-1 at a depth of 9,020 - 9,150 feet, and entering the fracture system after traveling up the poorly cemented annulus.) The drilling rig was released on 27 October 1975.

3.1.3 Investigation of the EE-1 / GT-2 System

In late 1975 and early 1976 a series of experiments was conducted in GT-2 and EE-1 to investigate and try to improve the hydraulic connection between them. The first production of hot water from an HDR production-injection loop occurred on 4 December 1975. Water was injected into EE-1 at a rate of 9 gpm and produced from GT-2 at a rate of 7 gpm and a production temperature of 30°C. Tracer tests conducted in March 1976 using sodium fluorescein indicated an indirect connection between the two wells and a reservoir volume of 8,000 to 10,000 gallons.

The relationship between injection pressure and fluid production rate is referred to as impedance. In the December 1975 test, impedance was $1,120 \text{ psi} \div 7 \text{ gpm} = 160 \text{ psi/gpm}$, which is very high and indicates a limited connection between the wells. Many experiments were proposed to reduce the system impedance: dissolution of minerals in the fractures by injecting sodium bicarbonate or acid solutions; propping the fractures open with sand; and redrilling one of the wells to directly intersect the fracture in the other. The first was tried in November 1976. First a dye tracer

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experiment was run to estimate the system volume. Subsequently, water was injected into EE-1 and produced from GT-2 at an impedance of 75 psi/gpm and a production temperature of 65°C, after which 50,000 gallons of sodium bicarbonate were injected into EE-1 followed by 100,000 gallons of fresh water. Nearly one ton of silica was leached from the rocks and brought to the surface; however, the impedance of the system increased to about 100 psi/gpm and the reservoir volume remained unchanged. The failure of this experiment led to the decision to redrill one of the wells to directly intersect one of the major fractures created in the other.

Seismic data were then collected to determine acoustic velocities and relative hole positions, and to improve fracture mapping techniques. Because of the uncertainty of the directional surveys and therefore the relative locations of the two wells, a large magnet was lowered into the open hole of EE-1 on several occasions and repeated photographs were taken of a compass in well GT-2. This showed that EE-1 was northeast of GT-2.

The decision was made to redrill the shallower of the two wells (GT-2) in an attempt to intersect the large fracture made in EE-1, and additional information about the geometry of the fracture system was collected using induced potential logs, temperature/pressure/spinner logs and a "shear-shadowing" experiment. The last was based on the theory that shear waves should be completely attenuated in a fluid-filled fracture. Charges were detonated in well EE-1 at four discrete depths with geophones suitably located in GT-2 to record the signals. Charges were detonated with the system pressurized at hydrostatic pressure and at 1,550 psi (*i.e.*, with fractures inflated). The lack of shear waves in the two deeper shots indicated the presence of a water-filled fracture below 8,400 feet, which was consistent with the results of the induced-potential logs.

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Spinner and radioactive tracer logs run in EE-1 at this time showed that water was leaving the wellbore just below the casing shoe at 9,600 feet and traveling up the poorly cemented annulus to 9,020 - 9,150 feet, where it entered the fracture system.

3.1.4 Redrilling GT-2 (GT-2A and GT-2B)

The redrill of well GT-2 was planned as a side-track from 8,200 feet in order to intersect the upper part of the NW-trending EE-1 fracture at as shallow a depth as possible (8,700 feet) ~~by~~ *redrill.*
~~side-tracking GT-2 from 8,200 feet.~~ Drilling operations for GT-2A began on 6 April 1977. After several unsuccessful attempts to kick off the well using cement plugs, GT-2 was under-reamed with a 16-inch tool from 8,110 to 8,120 feet to create a ledge for side-tracking. A cement plug was emplaced to the top of the under reamed interval, and the well was side-tracked at 8,144 feet. Drilling proceeded with a 9-5/8-inch (reported diameter; may actually be 9-7/8-inch) bit to 8,590 feet, at which time the hole direction was N25°E and the angle of deviation was just over 9° from vertical. At 8,645 feet, pressure losses were noted in EE - 1, indicating that GT-2A had penetrated the EE-1 fracture. Drilling continued to a TD of 9,184 feet, which was reached in early May 1977.

A brief pressurizing experiment and a pump test indicated that the GT-2A / EE-1 system impedance was 35 psi/gpm. As this was considered to be "far too high for a convincing heat extraction experiment" (M.C. Smith, unpublished document), LANL decided to redrill GT-2 again in order to intersect EE-1's fracture at a greater depth.

GT-2B was side-tracked from GT-2 at a depth of 8,270 feet and drilled ENE to 8,767 feet, when a loss of pressure was noted in EE-1, which had been pressurized earlier. A core cut at this depth had several open fractures, and LANL concluded that the target had been reached. A pump test

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run at this depth indicated a system impedance of 15 to 18 psi/gpm, a considerable improvement from the previous system. An open-hole packer was set a 8,706 feet in GT-2B and the well was pressurized to 1,830 psi to further open the fractures and reduce impedance. After 20 hours of injection at 100 gpm and 1,000 psi in well EE-1, the production temperature in GT-2B reached 130°C and the impedance was 9.5 psi/gpm.

Drilling continued to a TD of 8,907 feet. A core taken at 8,893 feet showed indications of fluid flow in fractures. A 7-5/8-inch casing was then run in the hole from the surface to 8,520 feet; the bottom 1,500 feet of this casing were cemented. The hole was then cleaned out to TD and the drilling rig was released on 10 July 1977.

3.1.5 Investigation of the EE-1 / GT-2B System

To determine the system impedance, each well was shut in (in turn) while the other was pressurized by injecting at several rates. These tests indicated the following impedances to flow: near zero between the fracture system and well EE-1; on the order of 2.5 - 3 psi/gpm in the fracture network itself; and 6 - 7.5 psi/gpm between the fracture system and well GT-2B. From these results, it was concluded that GT-2B had not penetrated the fracture created in EE-1, but instead was drilled into one or more smaller, inclined natural fractures which had been re-opened during hydraulic fracturing operations; hence the higher impedance between GT-2B and the reservoir versus between EE-1 and the reservoir.

As discussed in the following chapter of this report, flow testing of the Phase I reservoir at Fenton Hill began with a test lasting several days in September 1977. EE-1 was the injection well and GT-2B the production well in all tests of the Phase I system. A longer flow test was initiated in January 1978. Between those two tests, a shear-shadowing experiment was run with the wells in static and pressurized conditions. In addition to using detonators to create the seismic signal,

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LANL tested a downhole signal generating tool developed by Dresser Atlas. This worked very well and greatly facilitated shear-shadowing experiments (also referred to as acoustic attenuation experiments).

Thereafter followed three tests of the Phase I system. During the third test in October 1978, leakage around the annulus in the injection well EE-1 increased from tolerable levels to about 20 gpm, and it was decided to re-cement the casing before undertaking any further testing.

3.1.6 Re-Cementing the Casing in EE-1

Cementing operations began on 8 January 1979. Various logs were run, sand was emplaced in the bottom of the well, a cement retainer was set inside the production casing at a depth of 9,542 feet, and water followed by cement was pumped down the drill pipe with well GT-2B open. After waiting for the cement to set, a cement bond log was run, indicating partial cement from the bottom of the casing at 9,600 feet up to 9,540 feet, good cement up to 9,080 feet, and "improved bond" in the old cement at higher levels.

Gas fracturing was then attempted in EE-1 in February 1979, but testing before and after the gas fracturing operations indicated no change in downhole conditions. Therefore, a massive hydraulic fracturing (MHF) operation was undertaken in EE-1 in March 1979 with injection rates and pressures up to 670 gpm and 3,000 psi, respectively. Although it appears uncertain that formation breakdown occurred during these operations, analysis of seismic data and later flow tests indicated that a new fracture had indeed been opened at 9,620 feet in EE-1, creating a larger surface area within the EE-1 / GT-2B system than existed with the injection point in EE-1 at 9,020 - 9,150 feet (behind the poorly cemented casing). There is no mention of the use of packers

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in the description of this MHF operation; it seems that the entire open hole section of EE-1 was pressurized.

After re-cementing the casing and opening the fracture at 9,620 feet in EE-1, two flow tests were conducted. Run Segment 4, undertaken in October and November 1979, showed that the recent MHF had indeed created a reservoir with a larger heat-transfer area than existed previously. Run Segment 5 and the subsequent "Stress-Unlocking Experiment" were undertaken from February through December 1980, completing Phase I of the Fenton Hill project.

3.2 Phase II

3.2.1 Drilling Well EE-2

Well EE-2 was spudded on 3 April 1979. A 26-inch hole was drilled to 1,785 feet, where a string of 20-inch casing was set and cemented. In the next (17-1/2-inch) interval a significant loss zone encountered at about 2,350 feet had to be sealed with several cement plugs. The top of the intrusive basement rock was encountered at 2,401 feet, and the 13-3/8-inch casing was set and cemented at 2,593 feet. There was considerable difficulty in cementing the lower part of this casing string; because of this, the well was unintentionally side-tracked out of the 13-3/8-inch casing near the top of the granite.

The 12-1/4-inch hole was deepened to the kick-off point at 6,992 feet, where directional drilling began and continued to a depth of about 10,000 feet. The well was drilled with a 12-1/4-inch bit to 11,576 feet, then deepened 10 feet with an 11-inch bit, another 10 feet with a 10-inch (reported diameter; may actually be 10-5/8-inch) bit, and thereafter with an 8-3/4-inch bit. While drilling at 13,940 feet, circulation was lost through a damaged zone in the 13-3/8-inch casing at 1,700 feet.

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A series of cementing operations was undertaken to seal the damaged zone, and 9-5/8-inch casing was run from the surface to 11,576 feet. It had been initially planned that the 9-5/8-inch casing would be cemented to the surface so that it would be firmly anchored along its entire length and thus able to withstand the thermally induced stresses during injection. However, for various reasons, the casing was cemented only from 10,600 feet to the casing shoe. Drilling then continued with an 8-3/4-inch bit to the total depth of 15,289 feet, which was reached on 12 May 1980.

The well took 409 days to drill. The primary reasons for the long drilling time were delays associated with directional drilling (correcting the hole direction and testing various mud motors and a turbodrill) and repairing the damaged 13-3/8-inch casing. Fracturing operations did not begin until after well EE-3 was completed.

3.2.2 Drilling Well EE-3

Well EE-3 was spudded on 22 May 1980, just after EE-2 was completed. The drilling rig was "skidded" about 150 feet to the new location. A 26-inch hole was drilled to 1,894 feet, where a major loss of circulation occurred. Cementing operations followed, and because of severe sloughing problems, LANL decided to set the 20-inch casing without curing the loss zone. Because of fill in the hole, the casing was not run to bottom but instead was set at a depth of 1,580 feet, and successfully cemented in two stages. Drilling proceeded with a 17-1/2-inch bit, and circulation was lost again almost immediately. LANL elected to drill without returns, although with some delays owing to water supply problems. The granite basement was encountered at 2,404 feet, and the 17-1/2-inch hole was terminated at 2,567 feet, where the 13-3/8-inch casing was set and cemented.

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A 12-1/4-inch hole was drilled without difficulties to 6,444 feet, where directional drilling began and continued to 10,417 feet. There were some problems in controlling hole direction and angle, and the hole developed tight spots that required reaming. There were two "twist-offs" during the directional drilling. The fish could not be recovered after the second twist-off, and after a 44-day fishing job, it was decided that the well should be side-tracked around the fish. In preparation for side-tracking the well, several cement plugs were set, but they did not harden sufficiently to enable a successful sidetrack (it was likely that the granite was harder than the plug). Eventually, a whipstock was permanently cemented in the hole above the fish to create a solid foundation for side-tracking the well at about 9,500 feet.

Directional drilling with a 12-1/4-inch bit resumed, and EE-3 was successfully oriented above and parallel to EE-2. Two or three fishing jobs were required in this interval, one lasting 45 days. Drilling was terminated when the hole reached a depth of 13,933 feet. A 9-5/8-inch casing was run from the surface to 10,374 feet, and cemented from the shoe to 7,280 feet. As in EE-2, LANL anticipated severe thermal stress in EE-3's production casing, and decided that pre-tensioning would be the best way to reduce the chances of casing failure. Therefore, after waiting for the cement to set, the 9-5/8-inch casing was tensioned by pulling at the surface with casing tensioning jacks, stretching it by about three feet. Casing slips were then set and the tensioned casing was cemented from 7,280 feet back up to 3,000 feet. The casing was tensioned again, stretching it another five feet, and the slips were set again. The rig was released on 25 August 1981, after 461 days of drilling.

3.2.3 Initial Hydraulic Fracturing Operations in Well EE-2

After removing a coating of black material that had formed on the walls of the open hole (from degradation of oil and other materials) in November 1981, natural formation permeability tests

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(referred to as Experiment 2003) were run by measuring water loss at various wellhead pressures up to 2,070 psi. These showed that EE-2 was extremely tight.

To monitor the seismic activity associated with the fracturing, a downhole three-component geophone package was installed at 9,600 feet in well EE-1, and an accelerometer package was placed in EE-3. For the first time, an on-line system developed by LANL was used to record and locate microseismic events in the field to generate maps of the evolving fracture system.

In April 1982, a large workover rig was mobilized to begin the fracturing work. First, an attempt was made to recover a logging tool that had been lost deep in the well; only the wireline was recovered. Then a notch was cut in the wall of the borehole at 15,128 feet, using a high-pressure abrasive jet perforation tool, to localize and help initiate fracturing. An inflatable packer was set about 165 feet off bottom, and on 2 May 1982 the well was pressurized to about 2,800 psi, at which point a failure in the system necessitated a shut-in of the well, with the pressure holding at 2,250 psi. While repairing a pressure transducer, the shut-in pressure declined by 33 psi. Pumping resumed, but flow and pressure conditions in the annulus of the well indicated that the packer had failed. Another packer was set slightly lower in the hole, and this time, the zones above and below the packer were pressurized to reduce the pressure differential across the packer. This technique of pressuring up the "backside" of the packer was used in most of the subsequent fracturing operations. However, during this test, when the open interval was pressured up to about 4,200 psi, the packer failed again, with no indication that fracturing had been initiated.

At this point, the packer failures led LANL to seek an alternate method of zone isolation: fracturing below a cemented liner. An unspecified length of 4-1/2-inch liner with a polished bore receptacle (PBR) at its upper end was set on a sand plug about 500 feet long. With the bottom of

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the liner at 14,698 feet, the liner was cemented in place using a cement specially formulated for a bottom-of-liner temperature of 300°C. The cement in the liner was drilled out and the sand plug was washed out to TD. Using a LANL-designed protective sleeve for the seal assembly, needed to protect the seals as they passed through the open hole between the liner top and the casing shoe, the PBR seals and the 4-1/2-inch fracturing string were installed, sealing the liner to the surface. The liner was pressure tested to confirm that high-temperature cement had created a high-pressure seal over the stimulation zone.

With the "backside" pressure (*i.e.*, in the hole above the liner) maintained at 2,000 psi, water was pumped through the liner into the 500 feet of open hole below it and formation breakdown was observed at a pressure of 4,800 psi. A total of about 138,000 gallons were injected before the service company's pumping equipment failed. This was Experiment 2011, conducted on 30 May 1982. There is no mention in the available documents of analysis of the seismicity generated from this hydraulic fracturing job.

On 4 and 5 June, fracturing through the PBR was tried again in Experiment 2012, and more than 800,000 gallons were injected. Analysis of seismic data indicated that two fractures had been created during this test: one at a depth of 14,402 feet, which initially extended downward at an angle for a length of about 1,300 feet, and then appeared to extend upward toward EE-3; and a second, parallel fracture which also extended downward at an angle from a depth of 12,992 feet. Although the seismic maps (produced using the hodogram method; see Chapter 5) showed that some of these fractures got close to the bottom of well EE-3, no connection was made.

A third attempt was made on 19 and 20 June (Experiment 2016) using higher injection rates. A total of 1,290,000 gallons was injected in this test, but analysis of seismic data showed that the seismically active zone was still by-passing EE-3. Location of events (using the hodogram

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method) showed that seismicity was initially occurring above the injection point, subsequently spreading in an oblate region dipping toward the west at 30° to 60° from vertical. It was also observed that the character of the seismic events was consistent with strike-slip displacement. No further fracturing was attempted in this deep zone in EE-2.

Fracturing was then initiated at a higher level in the well, where (if fracturing would occur along a similar trend as occurred in the deeper part of EE-2) the relative positions of the two wells made an intersection between the fracture and EE-3 more likely. Sand and clay were pumped into EE-2 up to a depth of 12,060 feet, leaving an open interval 475 feet long below the shoe of the 9-5/8-inch casing at 11,587 feet. A casing packer was set inside the casing 250 feet above the shoe, and on 19 and 20 July 1982 (Experiment 2018), the well was pressurized by pumping 240,000 gallons of water. Formation breakdown was observed at 4,500 psi, but failure of the fracturing string terminated the experiment early. Seismicity was observed adjacent to the injection zone in EE-2; with time, the seismicity migrated downward and toward the south, again creating an oblate region of fractures. A second, nearly parallel zone, located several hundred feet above the first, was observed later in this test. It is reported that the seismic character of at least some of these signals was consistent with normal faulting, indicating either a major change in stress regime or a different flaw structure in the rock as compared to the deeper zone.

A second attempt at fracturing the shallower zone (Experiment 2019) also was stopped prematurely because the fracturing string failed. A third attempt (Experiment 2020, 6 October 1982) still made no connection, and an analysis of the seismic data indicated that a very long stimulation with large volumes of water would be required to connect to EE-3. Therefore, LANL decided to begin fracturing operations in EE-3.

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There were three unexpected results from the initial series of hydraulic fracturing experiments undertaken in EE-2: 1) the orientations of the induced fractures; 2) the change in microearthquake source mechanisms with depth; and 3) the generation of significant quantities of CO₂ and H₂S. The last, in combination with the much higher fracturing pressures than was required in Phase I, was thought to be responsible for failures of the fracturing string by stress corrosion cracking during the hydraulic fracturing operations in the upper zone. LANL therefore ordered two fracturing strings that would better withstand attack by H₂S.

The first new fracturing string, a 4-1/2-inch OD L-80 VAM threaded and coupled string, was available "off the shelf" from a U.S. manufacturer; this type of string had been used in other applications where stress corrosion cracking was a problem. The second was a state-of-the-art (5-1/2-inch OD, C-90, Hydril upset, premium threaded, integral joint) tubing string based on designs for deep gas well production strings exposed to high pressure, high temperature and a severe stress corrosion environment.

3.2.4 Initial Hydraulic Fracturing Operations in Well EE-3

As in EE-2, the first step in hydraulic fracturing operations was to investigate the natural permeability of the well by injecting at different wellhead pressures. This was Experiment 2006, carried out late 1981. EE-3 did have some natural permeability, and began to accept injection readily at wellhead pressures of 1,480 psi or greater.

After completing the series of fracturing experiments in EE-2 described above, LANL began a series of fracturing experiments in EE-3. The first (Experiment 2023, 8 November 1982) was an open hole test (no zone isolation), during which 39,000 gallons of water were injected at a maximum pressure of 2,000 psi. All water injected into EE-3 was heated to 65°C to minimize the

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stress associated with cool-down of the casing, which had been landed with 1,000,000 pounds of tension to reduce wellhead growth during production. No seismicity was observed, and a temperature log indicated that most of the fluid entered a narrow zone at 10,450 feet, where a drilling break had occurred. This zone was then treated with lost-circulation material (LCM), an open-hole packer was set below it, the well was pressured up, and the packer failed (Experiment 2024).

Following the experience in EE-2, in the next test (Experiment 2025, 14 December 1982) EE-3 was plugged back with sand to 11,770 feet, and a 4-1/2-inch liner with a PBR at its upper end was cemented into the hole with its bottom at 11,389 feet. An open-hole section was created by washing out some of the sand. On the first attempt to stimulate below the liner, the annulus pressure began to rise when the injection pressure reached about 2,000 psi, and injection was terminated. It was later learned that a buckling failure had occurred at the top of the cement. On the second try, the well was pressured to a maximum of 6,600 psi, and although pressure stabilized for some time at 4,700 psi, there was no clear indication of formation breakdown.

In September 1983 (Experiment 2033), the open hole region between the casing shoe at 10,374 feet and the top of the cemented liner at 10,898 feet was stimulated with water heated to 65°C (to avoid over-stressing the casing). A total of 188,000 gallons were injected, and pressure data indicated formation breakdown. LANL concluded that this stimulation had decreased the distance between the "seismic clouds" in EE-2 and EE-3, but no connection was made. It is also stated that a distributed network of stimulated natural joints was created during these tests, rather than single, planar fractures, as were thought to have been created in Phase I.

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3.2.5 Massive Hydraulic Fracturing in EE-2 and EE-3

Having received the new fracturing string, LANL then decided to inject a very large volume of water (5.6 million gallons) into the upper zone in well EE-2 in a "Massive Hydraulic Fracturing" test (MHF, Experiment 2032). To protect the 9-5/8-inch casing from the planned stimulation pressures, which were higher than anticipated when the well was originally drilled and completed, a stimulation packer was set inside the 9-5/8-inch casing a short distance above the shoe.

Injection began on 6 December 1983 and continued for 60-1/2 hours, mostly at the maximum allowable pressure of 7,000 psi. Backside pressure was maintained at about 5,000 psi to minimize the pressure differential on the packer and cemented liner. The experiment was terminated when one of the components in the fracturing head failed. While attempting to shut in the fracturing string (which was flowing back unchecked from the zone that had been stimulated), heat-up of the annulus caused a relief valve to open, instantly releasing the backside pressure. At this point, the attempt to regain control of the well was determined to be too dangerous, and 225°C water was vented from the annulus of EE-2 for about 36 hours.

It was later discovered that the 9-5/8-inch production casing had collapsed above the stimulation packer and hydraulic communication with the 10-3/4-inch annulus had been established. Two later attempts to repair the well and re-establish pressure integrity were not successful (see below).

Seismic signals from EE-2's MHF were recorded by downhole instruments set in GT-2B, EE-1, and EE-3. Analysis of these data revealed that fractures were opened in a tabular zone (about 3,000 feet high by 3,300 feet wide by 1,300 feet thick) centered on the injection zone in EE-2, with a strike and dip of N8°W and 20°, respectively. The amount of energy released by these

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events was relatively small, leading LANL to conclude that there had been a significant amount of aseismic fracture opening. It was realized that the fractures developed during the MHF had not penetrated the "seismically quiet" zone around well EE-3, and plans were made to undertake a MHF in EE-3 to try to connect the two wells.

Before EE-3's MHF, however, LANL undertook several experiments to investigate the "seismically quiet" zone around well EE-3. Furthermore, an experiment was conducted to determine if injecting nitrogen into the annulus between the fracturing (injection) string and the 9-5/8-inch casing would provide sufficient insulation so that the water would not need to be heated during fracturing. The insulating properties of both nitrogen gas and nitrogen foam were found to be insufficient to protect the casing from thermal stress; therefore, the water for the MHF was heated to 65°C as in the earlier stimulation experiment.

Remedial work was then undertaken in EE-3 to repair a buckled section of the 4-1/2-inch liner and install a 5-1/2-inch tie-back string to cover the section of open hole between the 9-5/8-inch casing and the 4-1/2-inch liner. A buckling failure of the liner had occurred at the top of the cement, which, after several attempts at using overshot patches, LANL remedied by installing an internal patch between the uncemented tie-back liner and the cemented liner. After the patch was installed, the first of the two new fracturing strings was installed and connected to the patch liner with a PBR seal assembly, and the MHF of EE-3 began.

In Experiment 2042 conducted in May 1984, 2 million gallons of water were injected into EE-3 at a maximum rate of 420 gallons per minute and a maximum pressure of 6,000 psi. As mentioned above, the water was heated to 65°C to avoid excessive stress of the casing, as EE-3 had been designed as a production well rather than an injection well. Unfortunately, a pressure increase in the annulus indicated flow between the open hole section below the liner and a permeable zone

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just below the 9-5/8-inch casing shoe; this zone had been first identified by a loss of circulation during drilling. Nevertheless, the experiment continued.

Again, a tabular zone of seismic activity was identified, and again, the amount of energy released by seismic activity was very small, indicating aseismic opening of pre-existing joints or fractures. There was a distinct lack of activity near well EE-2, and no connection was made. At this point, as in Phase I, the decision was made to side-track one of the two wells into the seismic cloud around the other. Considering that a very large fracture system had been created around EE-2 in its MHF, LANL decided to re-drill EE-3 to intersect as large a portion of that system as possible.

3.2.6 First Repair of EE-2

During the autumn of 1984, well EE-2 was worked over to repair the 9-5/8-inch casing which had been damaged at the end of the MHF operation. The casing had collapsed near 10,700 feet, about 80 - 100 feet below the top of the cement (the 9-5/8-inch casing had been cemented only from about 10,600 feet to the shoe at 11,578 feet). The collapse occurred opposite a zone of intense seismicity observed during the later part of Experiment 2032. It is likely that the combination of the sudden release of backside pressure and the high fluid pressures in the seismically active zone caused the casing (which was under-designed and had been through many cycles of heating and cooling) to collapse where it did. The collapse allowed water to leak through the uncemented annulus behind the 9-5/8-inch casing up to shallow aquifers at about 2,400 feet, just above the top of the basement rock. Two zones were cemented: from 6,519 to 9,226 feet; and from 10,380 feet to the top of the old cement at 10,620 feet. The workover was completed in December 1984.

It is stated in the FY 1985 annual report that LANL then conducted a series of tests in which the reservoir surrounding EE-2 was "re-inflated" in a series of steps while temperature and

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radioactive tracer logs were run (in EE-2) to evaluate the response of the fractured region. However, no details of these tests are given in the available documents. Discussions with LANL personnel indicate that they believed these tests proved that the first repair of EE-2 had not been successful in restoring the integrity of the casing; this led them to the conclusion that the well was only suited to operation as a low-pressure production well.

3.2.7 Redrilling EE-3 (EE-3A)

Following the repair of EE-2, the workover rig was skidded to EE-3 to prepare the well for redrilling. After several unsuccessful attempts to side-track off cement plugs a whipstock was installed and the well was successfully side-tracked from a depth of about 9,300 feet. The rig drilled less than 100 feet of new hole and was then dismissed. In March 1985, a larger drilling rig was moved onto the well, and EE-3A was drilled along a trajectory designed to penetrate the seismically active regions mapped during Experiment 2032.

Before the reservoir was penetrated, an open-hole packer was set at 10,850 feet in a slow-drilled, in-gauge section of the well that was expected to be impermeable. This was the first use of a new type of packer, designed on the basis of an analysis of the failed open-hole packers recovered after earlier operations. It had been discovered that the packers had failed due to a combination of two effects caused by cooling at the onset of hydraulic fracturing: 1) reduction of packer inflation pressure; and 2) shortening of the fracturing string, which imposed an upward pressure on the packer. The new design, developed with extensive collaboration from a number of oil field service companies, the new design incorporated a LANL-designed expansion joint, a pressure multiplier to prevent deflation of the packer, and a choke sub below the packer to prevent packer deflation when the capacity of the multiplier had been exceeded.

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EE-2 was pressurized at a low pressure during the redrill of EE-3, and a connection between EE-3A and EE-2 was first noted when water began to flow into EE-3A while drilling at a depth of about 11,800 feet. The new packer was run several more times as the well penetrated the reservoir, enabling the zones where increased flow was noted by the mud loggers to be isolated, stimulated and evaluated.

After drilling to 12,205 feet, the new open-hole packer was set in EE-3A at about 11,500 feet, and the open interval below the packer was stimulated by injecting about 440,000 gallons of water at rates of 240 to 430 gpm and downhole pressures up to nearly 6,000 psi in Experiment 2059 (27 - 28 May 1985). The differential pressure across the packer, maintained by pressuring the backside, was probably on the order of 800 to 1,200 psi. Pressure rose rapidly in EE-2, and after two hours of injection in EE-3A, EE-2 was put on production and flowed at a relatively low rate. EE-2 was then alternately shut in to increase the back pressure and then vented several times; this steadily increased the flow rate to more than 150 gpm by the end of the test.

EE-3A was then drilled to its total depth of 13,183 feet, and three more zones were stimulated with the open-hole packer before running and cementing a 5-inch liner. The packer was first set at 12,566 feet; stimulation in this deep zone yielded no additional hydraulic connection to EE-2 (the fractures apparently grew downward, away from the seismic cloud mapped during Experiment 2032). Then the packer was set at 11,975 feet, and in Experiment 2062 (18 - 20 July 1985), another hydraulic connection was achieved between the two wells. The last stimulation of EE-3A was conducted with the packer set at 12,336 feet, and again, the fractures grew downward, resulting in no further connection. This left eight fractures between 11,532 and 12,300 feet in EE-3A which were connected to EE-2.

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In April and May of 1986, EE-3A was re-completed. A newly designed permanent open-hole packer was installed at 11,685 feet on a 5-inch liner that straddled the low-pressure leak above the high-pressure injection zone. However, this packer failed after three days. The well was plugged back with sand to 11,810 feet, and a liner was installed and cemented to produce the required seal. It had been planned to run the liner deeper in the well (bottom at 11,810 feet) using a "puddling" cementing technique (in which the cement is pumped in first and the liner is then run into the soft cement, thus preventing channels from forming in the cement). However, because the cement set early, the liner shoe ended up at 11,436 feet, and there was cement in the open hole to a depth of 11,810 feet (the top of the cement was at 10,950 feet).

A liner leak developed in a joint near the top of the cement. A washover of the top two joints of the liner allowed a clean back-off, and a screw-in sub was run on a tie-back liner, successfully completing the lining of the well. The cement below the shoe was then drilled out to 12,235 feet with a 4-1/2-inch bit, and a 5-inch by 4-1/2-inch tubing string was run and stung into the PBR on the top of the tie-back liner in preparation for the Interim Closed-Loop Flow Test (ICFT, Experiment 2067), which was conducted from 19 May to 18 June 1986. During this test, fluid was injected into EE-3A, heated in the underground fracture system, and produced from EE-2.

3.2.8 Second Repair of EE-2

During the ICFT, it was noted that fluid was still flowing up behind the 9-5/8-inch casing in EE-2. Furthermore, a 7-inch liner that had been installed through the collapsed zone after the clean-out of the 9-5/8-inch casing had also collapsed at 10,500 feet, and the well could not be logged below that depth. The objectives for repairing EE-2 were: 1) to isolate the "low pressure" reservoir at about 9,800 feet from the production zone; 2) to clean out the bottom of the well to 12,500 feet, if possible; and 3) to clear the casing collapse so the well could be properly logged.

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The repair was undertaken in FY 1987. The 5-1/2-inch tubing was removed, as was the damaged part of the 7-inch liner. It was found at that point that the 9-5/8-inch casing had also collapsed at 10,500 feet, and thereafter two unsuccessful attempts were made to mill through the collapsed zone. A short flow test was then conducted (injecting into EE-3A and flowing from EE-2) which showed no change from ICFT conditions.

As LANL management wanted to begin the Long Term Flow Test (LTFT), it was decided to leave EE-2 in essentially the same condition, except for undertaking a minor cementing operation to seal and stabilize that part of the casing behind which fluid was flowing. However, DOE convened an industry panel to make suggestions, and this panel concluded that re-drilling EE-2 would be the better plan, because the well could then be logged within the reservoir interval, and the effects of wellbore damage would not hamper analysis of flow test data.

3.2.9 Redrilling EE-2 (EE-2A)

The redrill plan consisted of: 1) plugging back EE-2 to a kick-off point at 9,800 feet; 2) squeeze-cementing the 9-5/8-inch casing through perforations to the surface; 3) milling a window in the 9-5/8-inch casing above the plug at 9,800 feet; 4) cementing in a whipstock to initiate the side-track; 5) drilling out about 15 - 20 feet from the original hole, then turning the hole to parallel the original hole, following it through the reservoir; 6) installing a 7-inch liner from just above the casing window to the top of the reservoir at about 11,500 feet; and 7) installing and cementing a 7-inch tie-back liner from the top of the open hole liner to the surface.

The drilling rig was mobilized and drilling operations began on 8 September 1987. Cementing and milling operations were undertaken, followed by re-drilling parallel to the original hole. EE-3A

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was pressurized to enable detection of EE-2A's penetration into the reservoir; the first connection was noted just as the region of seismicity was penetrated while drilling at about 11,000 feet. Drilling continued to a total depth of 12,050 feet, numerous temperature logs were run, and the drilling rig was released on 16 November 1987.

A six day flow test (Experiment 2074) was then conducted in December 1987, during which water was injected into EE-3A and produced from EE-2A. Producing fractures were identified between 10,850 and 11,980 feet in EE-2A. Analysis of seismic data indicated few shear events associated with fracture creation or extension, but some long-period earthquakes, thought to represent tensile opening of pre-existing fractures, were recorded. Tracer testing was undertaken, which showed that the reservoir volume was similar to that measured during the ICFT, although the fracture volumes were smaller because the injection well was operated at a lower pressure than during the ICFT. Gamma ray logs showed many fluid entries in EE-2A and no main flow path, suggesting that there was no "short-circuit" in the Phase II reservoir. A test of an organic tracer was made, and analytical methods were improved to enable its detection at very low levels (down to 5 parts per billion).

The rig was mobilized again in May 1988 to run the 7-inch liner. The well was sanded back to 10,775 feet and the liner was run and cemented from the liner hanger at 9,498 feet to the shoe at 10,769 feet. The annulus between the 9-5/8-inch and 13-3/8-inch casings was also partially cemented at this time, and a 7-inch tie-back liner was then run from the surface to the liner hanger at 9,498 feet and cemented. Because this tie-back could be appropriately connected ("stung in") to the 7-inch liner hung lower in the well, it was set down on the liner receptacle and hung off in the wellhead. This defect in the liner did not cause any problems in subsequent operations. A high-pressure wellhead was then installed, and EE-2A was ready for testing.

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In a pressurization test conducted on 15 June 1988 (Experiment 2076), 50,000 gallons of water were injected into EE-2A at rates of 40 to 640 gpm, with wellhead pressures ranging from 1,500 to 4,300 psi. The results of this test showed that the same fractures noted in Experiment 2074 were active, and that at a given injection pressure, nearly twice as much fluid can be injected into the reservoir from the EE-2A side as from the EE-3A side (*i.e.*, the impedance between the well and the reservoir was lower near EE-2A).

The Phase II Fenton Hill wells were now complete and ready for the remainder of the Phase II flow testing, which consisted of the Long Term Flow Test (LTFT) and several other tests undertaken between 1992 and 1995.

3.3 Lessons Learned, Technology Developed and Technology Transferred

3.3.1 Phase I

Air drilling was used in wells GT-1 and GT-2, but it resulted in many episodes of the drill pipe becoming stuck in the hole. Therefore, in later wells, water or mud was used as the circulating fluid; this was more effective in removing cuttings from the hole. The experience with redrilling GT-2 illustrated the difficulty of side-tracking in the hard, granitic basement rock. This problem was resolved by under-reaming the hole near the kick-off point and setting a cement plug on the resulting ledge. This method was used successfully in GT-2A and GT-2B. Although mud motors used for directional drilling worked well, directional survey tools generally failed to operate at the temperatures encountered in the Phase I well. Novel techniques to determine when one well was approaching another were therefore developed; these included lowering magnets in one well while observing a compass in another, and acoustic ranging, in which a charge is detonated at

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successive depths in one well while a geophone records the seismic signals at equivalent depths in another.

Although it was hoped that GT-2 could be redrilled to intersect the large fracture created in well EE-1, it was not possible to do this. Instead, GT-2B intersected one of the smaller fractures connected to the larger fracture. The inability to intersect the large fracture may relate to difficulties in controlling hole direction or getting accurate directional information, or the poor reliability of the hodogram method used to locate seismic events (see Chapter 5), which may have led to incorrect determination of where reservoir fracturing was occurring. Interesting techniques were developed to determine when a well was approaching a fluid-filled fracture; these included self-potential and induced-potential logs run with the fracture system pressurized, and shear-shadowing, which uses the attenuation of shear waves in one well after the detonation of a charge in the other to make inferences about the existence, location and size of fractures.

An interesting by-product of the acoustic ranging and shear-shadowing experiments was the realization that detonators generated enough seismic energy to gather useful information, thus avoiding the difficulties associated with detonating larger charges downhole at high temperatures.

Beginning with GT-1, Phase I demonstrated that hydraulic fractures can be created in granitic rock. It is likely that this had never been done before. However, even in vertical wells, open hole packers performed only sporadically, and attempts to fracture through perforations were unsuccessful. Impression packers were successfully used to obtain images of the fractures in the wells. As discussed in the following chapter, the reduction of impedance (resistance to flow in the reservoir or between the reservoir and the well) was a major goal. Propping fractures with sand was attempted twice in Phase I, and had the desired effect of reducing impedance in the near-wellbore region.

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3.3.2 Phase II

The primary lesson learned in Phase II was that the observations made in the shallow reservoir did not necessarily apply to the deeper reservoir. In particular the concept of developing major, near-vertical fractures was not borne out in Phase II. Instead, hydraulic fracturing of the Phase II reservoir created a network of fractures which propagated away from the well at an angle, including, sometimes, downward. This led to the need to re-drill EE-3 as EE-3A, illustrating now the preferred development procedure which has been referred to as "drill-frac-drill" (as opposed to "drill-drill-frac"). Clearly, more than the regional stress field was controlling the pattern of reservoir fracturing, which is an important conclusion.

In trying to connect the two existing wells, the amount of water that had to be injected was larger than anticipated, and the realization that the fracture system could be extended by injecting greater volumes of water was an important one. The two Massive Hydraulic Fracturing (MHF) experiments illustrated this concept dramatically. However, as will be discussed in the following section, some of the reservoir volume created during the MHFs was not available during testing because the production well (drilled prior to the MHFs) was not located where it could completely tap the fractures that had been created; therefore, the benefits of conducting the MHFs were not fully realized. It is likely that water loss occurred in this inaccessible area. As will be discussed in Chapter 5, LANL made some estimates of the increased heat production that could be obtained if an additional production well were drilled into this fractured but hydraulically inactive part of the reservoir.

Advances were realized in directional drilling in hot, competent rock, including the improvements in the operation of mud motors at high temperatures and the development of a turbodrill. Despite these, an extraordinarily long time was needed to drill the original Phase II wells. In part this was

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because a great deal of time was spent drilling with water, which is not as efficient as mud in circulating cuttings out of the hole. Problems controlling hole direction, curing lost circulation, repairing casing damage and fishing out stuck drill pipe also were major causes of delays in drilling. However, it should not be forgotten that this was a research project, conducted during an oil drilling boom when personnel experienced in drilling deep geothermal wells in hot, intrusive rocks were difficult to find and retain. In that context, excessive drilling costs may be tolerable.

An evaluation of the reasons for the high costs and long times required to drill EE-2 and EE-3 is not part of the scope of this study, and there is little reason to undertake such an investigation.

The two redrilling operations went much more smoothly, and were completed on schedule.

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The completion of the Phase II wells for hydraulic fracturing was somewhat problematic in that long sections of open, deviated hole were left to be fractured. The open-hole packers that had performed so sporadically in Phase I continued to present problems in the initial Phase II fracturing attempts, so LANL took another approach, cementing liners into the holes and fracturing through them using casing packers and the polished bore receptacle to seat the fracturing string. This technique was used successfully in the first deep fracturing jobs in EE-2 and EE-3. The failure of a component during EE-2's MHF was initiated by the mechanical failure of a surface component of the fracturing string. This, combined with operational error in response to the failure, led to the failure of downhole equipment.

Later, the mechanism of failure of the open-hole packers was investigated, and a new packer system was designed. This represented a major advance for HDR technology; however, the amount of time required to install the packer, do the fracturing and retrieve the packer was still excessive (three weeks at best) by industry standards. These packers have never been used by the geothermal industry as far as we know, and now the company that developed them (Lynes) has been acquired by another service company (Baker Oil Tools) and no longer exists as a separate

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entity. It is possible that the knowledge base needed to manufacture these packers commercially no longer exists at Baker. LANL staff developed and bench-tested prototype expandable metal packers that could also be used for this type of work, but a complete deployment, operation and retrieval system was never developed, so they were never tested downhole.

Several other novel techniques were developed in the course of repairing or otherwise modifying the completion of the Phase II wells, but these were specific to the problems at hand, and would have little general application in the geothermal industry.

In the original Phase II well intended for production (EE-3), the production casing was landed in tension to minimize the movement of the wellhead caused by expansion during production. It was not anticipated that a fracturing job would be needed in EE-3. However, when the wells could not be connected by hydraulic fracturing in EE-2, EE-3 was fractured, during which operation it was necessary to heat the water in order to minimize the cooling of the casing. This raises an interesting point about the design of the wells with regard to flexibility in their use. If a well is to be used for production, it must withstand high temperatures but relatively low pressures. Conversely, an injection well must withstand high pressures but not high temperatures. During long shut-in periods wells of both types would equilibrate to ambient reservoir conditions. Therefore, unless a strategy of reservoir development is used that requires stimulation of only the injection well, HDR wells must be appropriately designed and completed to withstand the full range of temperatures and pressures that may occur. This has implications for the selection and use of casings and cement, and many other aspects of well design and completion. It certainly supports the use of the "drill-frac-drill" strategy; however, even if this approach to reservoir development were used, flexibility of well use might still be desirable.

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The choice of hydraulic fracturing method also affects how the wells must be completed. Fracturing by pumping through the casing, rather than through a fracturing string, would be advantageous in several ways. However, in order to implement this method the well casings would have to be designed to withstand the pressures required to break down the formation. Similarly, cement jobs would have to be good enough not to break down or degrade during fracturing operations.

It is interesting to note that, contrary to typical geothermal well completions, the production casings of the Fenton Hill wells were often only partially cemented. The benefits of performing complete versus partial cementing jobs in HDR wells may merit further investigation. Partial cement jobs were selected by LANL as the best way to handle the thermal cycling (between injection and production) at high pressures. This and other aspects of the well designs used in support of hydraulic fracturing operations in the Phase II wells were based on completion practices used at the time in high-temperature (200°C), high-pressure gas wells, which were routinely stimulated using some of the same techniques applied at Fenton Hill. The partially cemented casing in well EE-3A performed without a catastrophic failure in more than 10 years of intermittent operation.

A considerable amount of effort was spent developing high-temperature cementing practices in collaboration with service companies; this effort contributed to improvements in the completion of deep, high-temperature gas wells. A wellbore heat-transfer computer code was developed specifically to help estimate the rate and duration of water circulation required to cool down the well prior to cementing operations, to estimate the amount of water needed to displace the cement, and to support other drilling activities.

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Finally, it came as a surprise in Phase II that there was an appreciable amount of H₂S present in the reservoir. While this has implications for fluid production from the reservoir, its main impact at Fenton Hill was its effect on fracturing strings, which failed consistently after venting following fracturing jobs. This was resolved by obtaining two fracturing strings of more suitable metallurgy and with better joint connections. These fracturing strings, based on similar designs used in deep, high-pressure gas wells, successfully eliminated the failure problems. The potential effects of H₂S on tubulars may need to be taken into account when performing stimulations in other geothermal reservoirs.

The drilling and completion practices used at Fenton Hill have not been adopted by the geothermal industry because they are not suitable for most geothermal wells. However, future developers of EGS may benefit from a review of the Fenton Hill experience, particularly the methods of zone isolation and completion used for hydraulic fracturing operations. It is likely that, in initial EGS projects, existing wells may be stimulated; this is exactly what was done at Fenton Hill (the wells were drilled, left with long sections of open hole, and then fractured). Therefore, the methods used and the results obtained at the Fenton Hill site should provide valuable information to EGS developers.

4. FLOW AND TRACER TESTING

4.1 Phase I

4.1.1 Operations Summary

The Phase I drilling and hydraulic fracturing operations that preceded flow testing have been described in Chapter 3. To summarize, well GT-2 was drilled as the production well and reservoir rocks were hydraulically fractured. Well EE-1 was then drilled as the injector, towards the largest known GT-2 fracture. This operation did not successfully establish hydraulic communication between the two wells, so GT-2 was twice side-tracked and redrilled towards EE-1. The last redrill (GT-2B) succeeded in intercepting the apparent top of a large fracture that connected to EE-1, and the volume of rock fractures that could be accessed through this connection has been named the "First Reservoir".

A goal of these operations had been to obtain the maximum possible effective heat transfer area at a reasonably low flow impedance. It was understood that this combination was needed for high rates of heat extraction, because high impedance could force the use of high working pressures, which in turn might cause high downhole water losses; it would certainly increase the energy needed to pump fluid through the system.

The Phase I flow tests consisted of five major "Run Segments", plus miscellaneous other experiments and shorter flow periods, the most significant of which are included in table 4.1. The Phase I tests were all assigned experiment numbers, which are listed in table 4.1, insofar as they were stated in the available documents (see the list of references, Chapter 6).

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Run Segment 1 was a four-day test conducted in September 1977 to shake down the flow test system. Run Segment 2 began in late January 1978 and continued for 75 days, using four different injection pressures and a typical production wellhead pressure of 160 psi. Run Segment 3 (September and October 1978) was the first "high back-pressure" experiment, during which the production wellhead pressure was maintained at 1,400 psi.

During Run Segment 3 there was an increase of water losses that was traced to bad casing cement, which allowed water to flow up through the annulus, exiting into surrounding rocks at depths as shallow as 2,500 feet. To correct this problem and to attempt the formation of a larger reservoir fracture system, EE-1 was re-cemented near bottom and hydraulically fractured again. These operations succeeded in developing the "Second Reservoir," which proved clearly to be larger than the First. The distance between reservoir inlet and outlet (spacing between permeable zones in the two wells) increased from about 330 to 990 feet, and the calculated fluid volume and effective heat-transfer area both increased.

Run Segment 4 was then conducted for 23 days in late 1979; back-pressure at the production well was alternately increased and decreased during this test. Run Segment 5 was a 286-day test at low back-pressure. This was followed by a two-day "Stress Unlocking Experiment" (SUE), and then by six days of post-SUE flow to determine the effects of the SUE.

The SUE had the overall objective of overcoming the normal forces that were holding fracture faces together in frictional contact, allowing shear slippage and microseismicity. More specifically, the test sought to: 1) produce microseismic signals from the reservoir by releasing the accumulated stresses caused by prior heat extraction; 2) reduce fracture flow impedance; 3) provide the first cycle of a "huff-puff" mode of reservoir heat extraction during which the system pressure could be varied cyclically; and 4) investigate the possibility of studying changes in

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reservoir spectral pressure response (the frequencies of wellhead pressure oscillations) with respect to reservoir size and flow impedance. The injection requirements of the test exceeded the pump capacity on-site, so pumps were rented.

The SUE consisted of pumping water into the injection well, EE-1, and then briefly into the production well, GT-2B, at about 2,200 psi. During this injection no water was produced from either well, except from the pre-existing annulus leak at EE-1, which flowed at a rate of 24 gpm at the start of injection and peaked at 59 gpm about 18 minutes after injection into GT-2B ceased. The total injection period was about eight hours long. After injection stopped, both wells were left shut-in for about two hours, and then GT-2B was opened to vented flow (surface disposal, no recirculation). After six hours of venting, the flow was switched to normal Run Segment 5 recirculation mode, and testing continued for six more days. When the final shut-in took place on 16 December 1980, the tests of the Fenton Hill Phase I reservoir were finished.

4.1.2 Flow Path and Process System

The basic flow diagram and process system for the flow tests is shown in figure 4.1. The system is normally operated in a closed-loop mode, with water continually re-circulated through the reservoir and makeup water added to compensate for downhole losses. The separator was included to allow removal of dissolved gases that could, hypothetically, build to a concentration that would allow gas bubbles to form in the pumps or other parts of the system, potentially causing damage and increasing flow impedance. As it turned out, gas levels remained low enough that routine separation was not needed.

The heat exchanger was air-cooled, and the typical temperature of water at the outlet of the heat exchangers was about 25°C. In May 1980, during Run Segment 5, the heat exchanger was

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replaced briefly by a 60 KW binary power plant. Due to mechanical problems, no sustained generation from this plant was achieved.

4.1.3 Instrumentation and Data Gathering

Certain instrumentation and data gathering procedures were common to most or all of the flow tests. These included:

- Pressure, temperature and flow rate measurements at various points in the process system; some 37 points were monitored during Run Segment 5.
- Periodic downhole pressure, temperature and spinner (PTS) logging.
- Continuous surface seismic monitoring using an array of six seismometers located within ½ mile of the site, five relatively shallow borehole stations located within about 6 miles of the site, and the Los Alamos National Laboratory regional net (nearest station about 6 miles from the site). The sensitivity of this array extended to Richter earthquake magnitudes of 0 to -1.5, and it was limited by the nearly 3 km depth of the reservoir and attenuation in near-surface sediments and volcanics.
- Downhole seismic monitoring during Run Segments 4 and 5, using an array of 12 geophones (or "sondes") on three axial directions in well EE-2, which had been drilled for Phase II, and a similar array in the production well GT-2B during the SUE. The sensitivity of the downhole sondes extended to events of magnitude -6.

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- Periodic tracer tests using sodium fluorescein (Na-F) and, later, irradiated ammonium bromide ($\text{NH}_4^{82}\text{Br}$) and ^{131}I . The radioactive tracers were detected by sampling and analyzing fluid from the production well, and also downhole using a gamma radiation logging tool, which can detect isotope-bearing water, even behind casing.
- Sampling of the water and dissolved gases for chemical analysis.
- Corrosion measurements.

4.1.4 Seismic Monitoring

Seismic events were monitored during all run segments, including the SUE, both to evaluate the potential seismic risk of HDR development and to evaluate reservoir geometry using microseismic events that might be triggered by fracturing, flow, heat extraction and other changes imposed on the reservoir rock system.

The events that occurred during Run Segments 2 - 5 were quite small and/or limited in number (see table 4.1, part A), but seismic data from Run Segments 4 and 5 contributed to the evaluation of reservoir geometry. The SUE produced a significant level of microseismicity.

4.1.5 Tracer Tests

The correlation of tracer tests with Run Segments is shown in table 4.1, and test results are summarized below in section 4.1.6. It is probable that sodium fluorescein (Na-F) was chosen as the primary tracer because it is non-toxic, non-reactive, easily detected at very low concentrations with a rugged, simple and precise lab or field instrument, and relatively inexpensive, in spite of the

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fact that it decomposes at high temperatures. This makes it a very useful geothermal tracer.

Decay rate studies were not published until after the Phase I tests (Adams and Davis, 1991); these indicated that 90% of an injected amount should remain after one month at reservoir temperatures of 210°C or less. The amount of decay occurring in the short residence time observed in the Phase I reservoir (first returns in a few hours) would have been insignificant, as reservoir temperatures were less than 200°C. The tracer was injected at the surface into the makeup water, and samples for analysis were collected downstream of the production wellhead.

Ammonium bromide with ^{82}Br was measured with a gamma ray detector that could be used downhole. Typically, both wellbores were logged at the same time, to enable the water entry/exit points to be defined and relative flow rates determined. ^{82}Br has a half-life of 36 hours and was injected at concentrations up to 400 mCi.

4.1.6 Test Conditions and Results

An outline of the basic flow conditions and results for each run segment and related tests is included in table 4.1. The injection wellhead pressure (WHP) was typically in the range of 1,220 - 1,420 psi, but sometimes higher (*e.g.*, during parts of Run Segment 4). Production wellhead pressure was typically 160 - 190 psi, but increased to 1,400 - 1,490 psi during two periods of high back-pressure flow that were instituted to evaluate the reservoir flow at these conditions. The high back-pressure tests were undertaken to determine if the reservoir flow paths would dilate and if the effective heat-transfer area would increase if the production well were throttled, thus holding the system at a higher overall pressure.

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The average heat extracted (reported in table 4.1, part B as MW_t or $MW_{thermal}$) was determined simply from flow rate and the temperature drop across the heat exchanger. The range listed for Run Segment 2 (3.1 to 4 MW_t) represents different values reported in two different data sources.

Production wellhead temperature (WHT) fell rapidly during the tests of the smaller First Reservoir, but was more nearly stable when the Second Reservoir was tested during Run Segments 4 and 5. While temperature declines are related to cooling of reservoir flow paths, initially at about 200°C, the wellhead temperature (and available thermal energy) is also very sensitive to heat loss in the wellbore, which was considerable at the relatively low flow rates of the system.

Flow impedance describes the relationship between flow rate and applied pressure. The values of impedance included in table 4.1 include a "buoyancy" correction, which accounts for the pressure difference between the reservoir inlet and the reservoir outlet by normalizing both points to the same elevation. This is done by adding to each wellhead pressure the hydrostatic pressure in the respective wellbore, then correcting for elevation difference using an average reservoir fluid density calculated from averaged temperature and the elevations of fluid entry/exit points determined from PTS logs, drilling data and tracer data. The hydrostatic pressure can also be calculated from wellbore temperature logs, or taken directly from wellbore pressure logs.

For the Phase I HDR studies, inlet elevation was taken as the bottom of the injection well (EE-1) and impedance was defined in terms of exit flow, so that impedance could be assigned to each of several production fractures and a weighted average calculated for all of them. Fracture impedances of about 9 psi/gpm were considered desirable, because these might promote nearly self-flowing conditions, driven by the fluid density differences between the injection and production wellbores.

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The project also developed an alternative method of measuring impedance, and calculating separate "entrance", "main fracture" and "exit" impedance, using transient wellhead pressure measurements at each well upon shut-in.

During Run Segment 2, impedance declined dramatically. This is attributed to thermal contraction and continued pressurization from the injection well, which opened natural joints and therefore provided additional communication with the production well. The large change of flow impedance was probably due to extensive cooling of the entire fracture system, with consequent decrease of fracture-closure stress and partial opening of the fractures.

Water loss (table 4.1) is simply the difference between injection rate and production rate. It is subject to various factors, including reservoir inflation during initial injection, losses to the formation as a result of applied pressure, and losses due to leaks in the casing or up through the annulus around the casing. Corrections for casing leaks were needed for the latter parts of Run Segments 3 and 5, but we have not determined in detail how they were made. Typically, leakage rates can be measured and/or estimated from PTS logs, tracer data, annular returns to the surface (if any) and radioactive logs. The results are not always highly precise; the greatest uncertainty usually is associated with small leaks which comprise only a small percent of total flow.

Tracer modal volume (also called fracture modal volume) is defined as the volume of fluid produced between the time a tracer is injected and the time the highest (peak) tracer concentration reaches the production wellhead, after subtraction of both wellbore volumes. This value is considered, in a general sense, to be the most reliable indicator of the relative volume of reservoir fluid that actively circulates under given conditions; therefore, an increase of modal volume is probably caused by volumetric growth of the actively circulating part of the reservoir.

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The rework and hydraulic fracturing of EE-1 after Run Segment 3 caused a large increase of tracer modal volume; however, the initial flow impedance during Run Segment 4 was essentially the same as at the start of Run Segment 2. Because both measurements were done at low back pressure, it appears that from the point of view of impedance, the benefit from the six-fold increase of tracer modal volume caused by the hydraulic fracturing was offset by the increased distance between the inlet and outlet (from about 330 to 990 feet). Nearly constant flow impedance during Run Segment 4 could be attributed to a relatively small amount of cooling and constant pressure conditions during the test.

The growth of tracer test modal volume during Run Segment 5 could be attributed to heat-extraction and a consequent contraction of rock volume. Despite evidence for increases in heat-transfer area and reservoir fluid volume during this Run Segment, no evidence of impedance change due to cooling was observed.

Another tracer result which is sometimes reported but is not included in table 4.1 is the integrated (or integral) mean volume, which is the volume of water produced between the time of tracer injection and the time when tracer return at the production well becomes negligible. This is considered to represent the total volume of all flow paths that permit fluid to flow from the injection well to the production well. It cannot be determined precisely, because re-circulation of the tracer must be taken into account, and the tail of the tracer concentration curve is not measured when a flow test terminates before the tracer concentration has declined to zero.

4.1.7 Lessons Learned

The broader lessons learned about the Fenton Hill Phase I reservoir system from flow and tracer testing involve assessing: 1) reservoir heat-transfer area; 2) reservoir volume; 3) impedance to

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flow; 4) water losses during operation; 5) fluid chemistry; and 6) seismicity. Each of these is discussed briefly below.

1) Heat-Transfer Area

Matching the test data with two heat-transfer simulation models developed by LANL (see Chapter 5 for more details on these models) indicates that pressurization, hydraulic fracturing, heat extraction and thermal contraction all cause increases of the heat-transfer area. The heat-transfer area determined from numerical simulation was much smaller than other estimates of total reservoir fracture area, determined by: 1) inflation estimate (fracture pressurization and inflation from total injected volume divided by effective aperture); 2) diffusion estimate determined from water loss data; 3) seismic estimate (the vertical projection of the locus of seismicity divided by the number of fractures in the microseismic volume); and 4) "vent" estimate (the water volume vented from a well after long-term pressurization).

The smaller simulated heat-transfer area is explained by short-circuiting of the fluid flow from inlet to outlet. The most important criterion for heat-transfer area is separation between reservoir inlet and outlet. For continuous flow circulation it can be shown that, roughly speaking, the effective heat-transfer area is proportional to the square of the inlet-to-outlet spacing for reservoirs consisting of a single fracture, and proportional to the cube of the separation for reservoirs with multiple fractures. These guidelines must be modified when buoyancy or natural convection occurs, or for cyclic (huff-puff) heat extraction.

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2) Reservoir Volume

Tracer results indicate that reservoir modal volume can grow in response both to intense pressurization, as during hydraulic fracturing, and to routine heat extraction, which causes thermal contraction of the rocks on joint and fracture surfaces. There are good linear correlations between tracer modal volume increase (ΔV^0) during a Run Segment and thermal energy extracted (ΔE) during the same Run Segment. This implies that the reservoir volume growth during Run Segments was due to thermal contraction alone, and the cooled rocks were most probably near the reservoir inlet. Effects of pressurization, such as pore and fracture inflation and local, irreversible fracture propagation, were not needed to explain the correlation between ΔE and ΔV^0 during a given test.

Under low back-pressure, the slope of the linear relationship between ΔV^0 and ΔE during a given Run Segment is about 10% of what would be expected for free thermal expansion/contraction in a stress-free environment. When stress is relieved (e.g., during high-back pressure flow, in response to the SUE, or high-pressure hydraulic fracturing), the relationship between ΔV^0 and ΔE approaches the expectation for free thermal expansion/contraction in a stress-free environment.

It was not possible to correlate tracer modal volumes with the effective heat transfer areas that were estimated from numerical simulation. However, an interesting result of the Phase I tracer testing was derived from a comparison of modal volume and integrated mean volume. During some of the tests of the Phase I system, modal volume was as much as 80% of the integral mean volume, confirming the dominance of one or more major flow paths.

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3) Flow Impedance

Run Segments 2 and 3 usefully demonstrated a linear correlation between impedance and reservoir outlet temperature. For comparable temperature and pressure, impedance was unchanged. It was apparent that impedance in a large system would not change rapidly; the impedance drop after the SUE was attributed to self-propping caused by slippage along fracture faces near the exit, or by other induced changes of fracture geometry.

Impedance was highest near the exit from the formation into the production well, particularly during low back-pressure operation. This led to the concept that HDR systems may be "self-regulated," which helped to prevent "runaway" in which one fracture cools more than others and takes much of the flow, which would then further accelerate cooling. It was also concluded that because impedance was greatest near the production well, at least after short periods of observation, total impedance of the system should not depend strongly on wellbore separation.

4) Water Loss

The rate of water loss (under similar operating pressures) increased by 30% from Run Segment 2 to Run Segment 5. This increase is much smaller than increases of apparent heat-transfer area and tracer modal volume. An obvious conclusion is that the heat-transfer system and tracer volume utilize only a small portion of a much larger fracture system.

5) Fluid Chemistry

During flow, the concentration of steady-state total dissolved solids was typically 2,500 mg/l. Pore fluid total dissolved solids (TDS) is estimated to have been about 5,000 mg/l. Because the

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produced water carried relatively low TDS and showed little tendency for corrosion or scaling, the Fenton Hill Phase I system presented no geochemical hazards or impediments.

The fluid chemistry trends from each Phase I experiment indicate the existence of both a fracture-dominated flow path that includes the heat-transfer surfaces, and a high-impedance flow path consisting of connected microfractures and pores in the rock surrounding the heat extraction portion of the reservoir. Displacement (or flushing) of the indigenous pore fluid contained in the high-impedance flow path was the single most important geochemical effect observed in the Phase I experiments. The consequence of this displacement is that circulating fluid quality is largely fixed by the pore fluid concentration and displacement rate.

Assuming a constant pore fluid concentration, the fraction of total flow (steady state) that went through the secondary (high impedance) flow path was about 7 to 10% after 25 days (Run Segments 4 and 5), decreasing irregularly to about 3 to 5% after 250 days. After correcting for the annulus leak in EE-1, it is noted that the pore fluid displacement rate was approximately half of the steady-state water loss rate, as indicated during the periods of low back-pressure flow in Run Segment 4, and during Run Segment 5.

The volume of pore fluid displaced from the rock surrounding the fracture system into the fracture system was very large. Because this fracture system was pressurized everywhere above hydrostatic, circulating fluid should have been continuously lost to the surrounding matrix, which was sub-hydrostatic. That is, pore fluid from this sub-hydrostatic pressure field would have had to flow against a pressure gradient in order to enter the flowing system. Therefore, displacement of *in situ* or connate water by injected water probably occurred by fluid sweep along secondary flow paths with impedance intermediate to that of the main (*i.e.*, lowest impedance) fracture system and that of the unfractured reservoir rock.

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No seismic hazards were observed; the magnitude of the largest microearthquake was less than -1 on the extrapolated Richter scale. Significant microseismic activity was generated during initial fracturing, at pressures above a certain threshold, which may be related to the minimum earth stress (although this is uncertain). The events observed during the initial stage of pressurization were generally clustered about a vertical plane whose strike remained remarkably constant; this is referred to as the "planar-event region." Continued pressurization and water-loss diffusion resulted in a general displacement of microseismic events in a "non-planar event region" which extended considerable distances (more than 1,500 feet) away from both the injection point and the initial (planar) locus of events. Data from Run Segment 4 suggested that the Second Reservoir was not planar, but highly jointed and multiply fractured, so that the potential reservoir, if sufficiently exploited, would represent a volumetric rather than an areal source of heat; this was also the case with the deeper Phase II reservoir.

During flow testing there was only a very low level of seismic activity associated with the active heat-transfer regions of the Phase I reservoir; apparently, these regions were rendered aseismic by the initial release of stress during hydraulic fracturing, combined with thermal depletion and rock shrinkage during production. Pressurization of the reservoir during the SUE resulted in significant seismic activity starting at pressures lower than those observed previously when the (uncooled) system was pressurized. Furthermore, this augmentation of microseismicity appeared to originate in regions just outside and peripheral to the previously active heat-transfer regions. If reproducible, this seismic behavior held promise as a means of following the location(s) of reservoir heat-transfer, by conducting period stress unlocking via pressurization, with seismic event location monitoring.

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4.1.8 Technology Developed and Transferred

This section describes those techniques or tools developed up to about 1981 which relate to flow testing, fluid chemistry and tracer tests; other methods, instrumentation and equipment, such as logging tools and seismic analysis, are discussed in Chapter 5 of this report.

A downhole fluid sampler was designed to operate reliably at temperatures above 260°C, which was generally above the limit of commercial downhole sampling tools. As of 1985, this sampler had been used successfully in Fenton Hill wells, in geothermal wells in California, Nevada and New Mexico, and to sample 285°C brines issuing from sea floor vents under the Pacific Ocean off the west coast of Mexico.

A chemical analysis and test laboratory was built to monitor the chemistry of produced, injected and downhole fluids, and the chemistry of solids (rocks and scale). In the same facility, autoclave experiments on water-rock interactions at reservoir temperatures that apply both to the HDR studies and to hydrothermal systems in general were carried out. There were also laboratory studies of fluid dynamics in rough-walled fractures, rock mechanics and thermal stress cracking. The possible use of pleochroic haloes in biotite as a rock geothermometer was investigated. The intensity of these haloes, which form in biotite around included zircon grains as the result of alpha particle radiation damage, is a function of both time and temperature. Samples from the Fenton Hill deep holes were used to calibrate the method.

Neutron activation analysis methods were developed to determine trace and minor element concentrations in geothermal system waters, bulk rock samples, separated mineral phases, and intergranular salts. Laboratory experiments were conducted to determine the most suitable chemical and radioactive tracers for use in the HDR flow tests, and to develop sensitive methods

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of analysis that would not be affected by interferences. Further experimentation and testing was conducted to identify chemicals with a predictable thermal decay rate that could be used as tracers to investigate reservoir temperatures. As of 1985, these had identified the hydrolysis reaction of ethyl acetate as a candidate. Nearly 20 different organic chemicals were studied.

A program of chemical monitoring and modeling of spring, well and surface waters was undertaken in the Fenton Hill region, to provide assurance that site operations had no effect on water supplies in the area. This program was extended to include investigation of a high-temperature hydrothermal system in the nearby Valles Caldera, and investigation of other hydrothermal systems outside of the area.

Investigations into estimation of fracture aperture (average thickness of the fluid layer in contact with rock) were conducted using the concentration of radon in produced fluid. Radon is a decay product of the small amount of radium present in the reservoir rock.

Two computer codes for simulation models of heat-transfer were developed by LANL during Phase I of the Fenton Hill project: the "independent fractures" model; and the "multiple fractures" model. These are described in Chapter 5 of this report. In addition, numerical simulation studies were undertaken with "FRIP" (Fluid-Rock Interaction Program), which was first developed by the British Hot Dry Rock Program and later modified in collaboration with LANL. This code considers simultaneously the effects of earth stresses, hydraulic pressure, fracturing, heat extraction and fluid flow.

LANL also modified "TSAAS", a code originally written to solve transient or steady-state thermoelastic stress problems on a two-dimensional plane or axis-symmetric grid with orthotropic temperature-dependent properties. The modifications were made to accommodate coupled stress,

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temperature and pore pressure effects. Another major modeling effort was the development and use of LANL's FEHM (Finite Element Heat and Mass) simulator, which calculates the flow and temperature distributions in fractures, permeation into the adjacent rock, and the stress distribution in the reservoir. Precursor codes included GEO and REX.

In addition, the "Muskat" technique for evaluation of the transient pressure data was modified to determine separate impedances for the reservoir entrance, exit, and fracture, without bouyancy calculations (Zyvoloski *et al.*, 1981).

Analytical models were also developed to evaluate reservoir chemistry (TDS) trends. This used a generalized mass balance model that took into account the temperature distribution, flow rate, water loss, water makeup, and dissolution and precipitation rates for minerals, with the ability to split the reservoir flow into paths of different temperature and flow rate, in order to distinguish major fracture pathways from high-impedance pore spaces where pore fluids would be displaced by the added system water. Techniques for analytical modeling of tracer recovery trends were also developed.

4.2 Phase II

4.2.1 Operations Summary

The Phase II drilling and hydraulic fracturing operations that preceded flow testing have been described in Chapter 3. To summarize, wells EE-2 (anticipated to be the injector) and EE-3 (anticipated to be the producer) were drilled to lower and higher elevations, respectively. The wellbore positions and orientations were selected with the expectation that hydraulic fracturing would produce results similar to those obtained in Phase I: the wells would be connected by one

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or several major fractures that would be nearly vertical, and strike approximately north-northwest. This did not happen; instead the fracturing operations in 1982 produced three-dimensional distributed networks of stimulated natural joints, rather than single planar fractures, and the joint networks were inclined in a way that did not connect the two wells.

Renewed fracturing in December 1983 still did not connect the wells, but the analysis of 850 high-quality seismic events served to define further a microseismic zone around EE-2 with an ellipsoidal volume of about 0.05 km^3 (about 1.8 billion cubic feet). Fracturing in May 1984 again failed to connect the two wells, and microseismic data revealed that the reservoir was developing approximately along the trajectory of the inclined portion of EE-2, in a way that was unlikely to results in a connection between the two wells.

Therefore, in March 1985, well EE-3 was side-tracked and re-drilled (as EE-3A) through the zone of fractures created in EE-2. Limited communication was obtained, but EE-3A was still to be fractured (May 1985), deepened (June 1985) and fractured three more times before the decision to begin flow testing was made. Only one of the last three stimulations produced additional communication.

The EE-2 / EE-3A system consisted of a large, fractured, 240°C reservoir at about 11,600 feet. The two wells, each with approximately 1,000 feet of open hole, were separated by 300 to 500 feet and the flow-connected volume (at operating pressures in the range of 1,400 to 4,000 psi) was on the order of 550 to 700 million cubic feet. The seismically active area was, as mentioned above, an order of magnitude greater.

Phase II flow testing (table 4.2) began in May 1986 with the 30-day Initial Closed-Loop Flow Test (ICFT), during which fluid was injected into EE-3A and produced from EE-2. Production rate and

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temperature increased during this test as the Phase II reservoir inflated to a pseudo steady-state volume. During the test it was noted that fluid was flowing up behind the 9-5/8-inch casing in EE-2; in addition, the 7-inch casing in EE-2 had collapsed above the production zone and the well could not be fully logged. Therefore, in 1988, this damage was repaired by plugging back, side-tracking and re-drilling, with the new wellbore (EE-2A) essentially parallel to the original hole (EE-2).

As detailed in table 4.2, flow testing got underway again in April 1992, with EE-3A used for injection and EE-2A used for production. The first phase of the Long Term Flow Test (LTFT) ran from April to July 1992, followed by an Interim Flow Test (August - September 1992), two high back-pressure tests in December 1992 (during which the production wellhead pressure was kept at 1,800 and 2,200 psi), the second phase of the LTFT (February - April 1993), a pressure stimulation test in April 1993 (during which EE-2A was shut in for 25 minutes on each of three days) and some cyclical flow tests in May 1993 (during which the production wellhead pressure was increased for 16 hours on each of three days).

There was a two-year hiatus in flow testing before the Reservoir Verification Flow Tests (RVFT) were conducted in May - June 1995, followed by a load-following experiment in July 1995 (during which the production wellhead pressure was reduced from 2,200 psi to lower levels for four hours on each of six consecutive days) and a final tracer test, which was also conducted in July 1995.

Importantly, the Phase II experience led to a re-evaluation of the nature of fractures in the Fenton Hill reservoir. The original concept of newly formed, vertical fractures was abandoned, at least for rocks at the Phase II reservoir depth. Instead, all the new evidence pointed to the opening of existing but previously sealed joints. The initial joint openings were found to occur in a direction

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approximately orthogonal to the least principal earth stress; other joint sets opened at higher pressures.

4.2.2 Flow Path and Process System

The flow path used in testing for Phase II was similar in outline to that used for Phase I (figure 4.1), but with new equipment as follows:

- Injection pumps used during the first phase of the LTFT: reciprocating, adjustable for a wide range of pressures and flow rates, maximum volume of about 175 gpm at 5,000 psi, diesel powered. Two pumps were set up, to operate on an alternating schedule. Both failed in July 1992 and were later replaced by one, then another, centrifugal pump (see below).
- High-pressure (5,000 psi) side of the system: injection pump, piping to injection wellhead, both wellheads, wellbores.
- Low-pressure (1,000 psi) side of the system: particle/gas separator, air-cooled heat-exchanger, make-up water pump, connecting pipeline.
- Automated operation, computer control.

4.2.3 Instrumentation and Data Gathering

This was much the same as for Phase I:

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- Pressure, temperature and flow rate measurements at various points in the process system, connected to the automatic, computer-controlled operating system.
- Periodic downhole pressure, temperature and spinner (PTS) logging.
- Continuous surface seismic monitoring using a new MASSCOMP data acquisition system.
- Downhole seismic monitoring using geophones in EE-1 and other boreholes.
- Periodic tracer tests using sodium fluorescein (Na-F), para-toluene sulfonic acid (p-TSA), and ^{123}I (instead of ^{82}Br), with the radioactive tracer used for both shut-in and flowing spinner logs.
- Sampling of the water and dissolved gases for chemical analysis.
- Corrosion measurements.

4.2.4 Tracer Tests

The thermal instability of sodium-fluorescein (Na-F) at temperatures higher than 210°C has been described in section 4.1.5. Para-toluene sulfonic acid (p-TSA) was found to be thermally stable and suitable as a geothermal tracer during the time between the Phase I and II flow tests. It is much more expensive to analyze than Na-F, more difficult to measure at very low levels, and laboratory analysis is required. During the Phase II tests, p-TSA was usually used simultaneously with ^{82}Br or with Na-F, which clearly showed signs of thermal (or other) decay or adsorption, in spite of the short system residence time.

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Numerical modeling of tracer behavior was done using various codes (see below). For example, DuTeaux and Callahan (1996) used GEOCRACK to compare the theoretical returns of three tracers: one non-reactive; one adsorptive; and one thermally unstable. This work was investigative, and did not describe any attempts to match the actual tracer test results.

4.2.5 Test Conditions and Results

An outline of the basic conditions and results for each separate Phase II flow test and the most significant related activities is included in table 4.2 (parts A and B). This is analogous to table 4.1, except that reservoir pressure drop (buoyancy-corrected) has been added in part B.

Various activities are not included in table 4.2, such as: tracer, injection and flow tests during drilling and hydraulic fracturing; periods of reservoir venting, when the production well was opened and produced while the injection well was shut-in; measurements of reservoir pressurization and inflation; and long-term measurements of reservoir leak-off (water loss) rate at high pressure. For example, there was a prolonged period of venting during late 1986, after the ICFT, and the reservoir was pressurized at 1,000 to 2,800 psi, sometimes with and sometimes without make-up water, throughout 1989 - 1991. While these activities revealed important information about the Phase II reservoir at Fenton Hill, the available documents did not include many details of these operations or of the results and conclusions from them, and discussion with LANL personnel and others indicates that the data from these tests have not been fully analyzed.

The Phase II injection and production wellhead pressures (WHP) were much higher than during Phase I, with injection typically taking place at 3,960 psi and production at 1,400 psi and 2,200 psi. Exceptions are noted in table 4.2. Basically, the system was operated at the highest injection pressure that could be sustained without causing reservoir growth, as indicated by the onset of

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microearthquakes and a dramatic increase in water loss. High back-pressure was considered necessary to hold open the fluid-producing joints near the production well, thus reducing impedance in that part of the reservoir.

During the ICFT, which was the first test of the Phase II reservoir, production temperatures increased throughout the test to their final value of 192°C (at the production wellhead) and 232°C (downhole near the main fluid entries). The production rate also increased (to 200 gpm at the end of the test) and impedance decreased from 64 to 18 psi/gpm.

Tracer modal volume indicated a reservoir about twice as large as the Phase I reservoir, and tracer recoveries were lower, indicating a greater water loss than in the Phase I reservoir. Tracer modal volume was about 30% of the integrated mean volume. The fluid chemistry was clearly different, with about two to three times the TDS observed in Phase I. Gas concentrations were also higher.

During the ICFT, seismicity occurred in the north-striking tabular region that had been defined by fracture operations. However, only the southern half (injection end) of the volume defined by the massive hydraulic fracturing (MHF) operations undertaken in 1983 was seismically active, and seismicity occurred only after there had been enough injection to "fill" the southern volume. The seismic inactivity of the northern half suggested that this region was shielded by the pressure sink around the production well. The northern area became seismically active after shut-in, but the shut-in pressures should not have been high enough to fracture reservoir rock. Considering this, and considering the location of the northern region, LANL postulated that these post-flow events actually occurred in the Phase I reservoir region, implying that a hydraulic connection exists between the two reservoirs. Further analysis of seismic data, temperature logs and flow test data could confirm this connection and provide insight into the mechanism of the connection.

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It was concluded from the ICFT that: 1) strategies for reducing reservoir impedance should concentrate on the region surrounding the production well; 2) the volume of fractured rock was equivalent to a sphere of diameter approximately equal to the separation distance between the injection and production points in the two wells; and 3) the seismicity distribution implied that further seismicity and reservoir extension could be controlled by introducing additional production wells surrounding the injection point.

After re-drilling EE-2 as EE-2A, the first phase of the LTFT was conducted. Although planned as a 12-month test, the LTFT ended prematurely after 16 weeks when both of the injection pumps failed because of a metallurgical problem associate with pump fabrication. However, there were several important results.

Thermal drawdown of the resource was not observed, as the production well ^{downhole}inlet temperature remained constant. Wellhead temperature dropped from 184°C to 183°C, however, as a result of a decline in production rate and consequent cooling in the wellbore between the fluid entry point and the wellhead. Tracer modal volume increased by 188% from May to July 1992, and only about 36% of this increase could be attributed to cooling effects (thermal contraction). Water loss was stable at about 10 - 12% of the injected volume, and, as planned, the test was aseismic (the injection pressure was kept below 4,000 psi to avoid causing any reservoir growth).

After the injection pumps failed, a smaller injection pump already on-site was used for the Interim Flow Test (IFT) in August and September 1992. The injection pressure was about 3,200 psi and the production well was throttled to 1,400 psi, as in the first phase of the LTFT. Few results are reported from the IFT, although water losses were estimated at only about 5%, which is the lowest reported for the Phase II reservoir. The test went on for six weeks, and was terminated by the failure of the pump.

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A mud pump was then rented, and testing continued with two tests at higher production wellhead back-pressure in December 1992. Again, few results are included in the available documents, except that water losses of 19 and 27% are reported for back-pressures of 1,800 and 2,200 psi, respectively.

The second phase of the LTFT began in February 1993 after an electric-powered centrifugal pump was obtained. As in the first LTFT, the injection and production wellhead pressures were 3,960 and 1,400 psi, respectively. The production temperature was 184°C at the wellhead and 228°C downhole; both of these are within one degree of the temperature observed during the first phase of the LTFT. However, water loss was lower at 7% (compared to 12% during the first phase), and tracer modal volume was 35% lower than indicated at the end of the first phase.

At the end of the second phase of the LTFT in April 1993, a pressure stimulation test was conducted. The purpose of this test was to determine if periodic shut-ins of production, while maintaining injection, would rapidly boost reservoir pressure in the vicinity of the production wellbore. This would further dilate joints in the region near the production well, leading to an increase in the flow rate upon re-opening the production well.

The background concept for this test was described by DuTeaux (1993): "The permeability of the HDR reservoir at Fenton Hill is sustained by hydraulic pressure which holds open flow paths within a naturally jointed body of hot rock. The hydraulic pressure acts on the *in situ* stresses of the jointed reservoir and against the compressibility of the rock. Heat energy is mined from the rock and carried to the surface with a circulation loop created by injection and production wells drilled into the jointed reservoir. Previous flow tests and various models validated by flow test data indicate that flow path apertures dilate with increasing pressure. Since the rate of flow increases with larger flow path apertures, increasing the hydraulic pressure exerted on the reservoir

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increases the reservoir's permeability. Similarly, given a sufficient driving pressure difference across the reservoir, pressure dilating the outlet flow paths near the production well results in a higher rate of production flow. Consequently, more thermal power can be produced."

The test verified this concept (table 4.2, part B), but only during the short period of three cycles and 10 hours of flow following the last shut-in. After this, the process computer system responded to the unanticipated fluctuation of a control parameter and shut in both wells. This occurred in the evening and the site was un-manned, so the experiment was effectively terminated. However, closing the production wellhead valve for 25 minutes every 24 hours on three sequential days had increased the total thermal energy produced from the reservoir on each of the second and third consecutive days. Total energy production was enhanced by 2.6% in the 24 hour period containing the last shut-in, as compared to the 24 hour period before production flow was interrupted. It was expected that additional cycles would have led, eventually, to a constant limit of total daily energy extraction.

The increase of energy production resulted from a progressive reduction of overall reservoir impedance, which allowed higher production flow rates and therefore less heat loss in the production wellbore. In addition, the water loss did not increase, but appeared to decrease during the test.

The results of the pressure stimulation test suggested that HDR reservoir operations should be evaluated in alternative production modes, such as cyclic production. Further periodic shut-in experimentation would not only provide information about reservoir behavior, but would also help design methods for reducing reservoir impedance and optimizing reservoir productivity. Further work on modeling this non-linear dynamic process was also regarded as appropriate, and as having the potential to help design further energy production optimization experiments. Without

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extensive experimentation or modeling, the optimal mode of pressure stimulation remained uncertain.

Further experimentation with this concept was undertaken during the cyclic flow tests of May 1993. These tests were notable for an increase of production flow rate that included a large jump when the production back-pressure was reduced for the third time, on 6 May 1993 (listed as 13 May in some documents). In less than a minute, production flow increased from 156 gpm to 231 gpm. Depending upon the point of reference, the average stable production rate increased by as much as 48%. Steady-state production flow was then resumed, and after 12 days, the flow rate was still 35% higher than before the tests, so it appeared that a permanent change of reservoir flow characteristics had developed. Production well log temperatures showed no decline, and so wellhead temperature increased due to the higher flow rate.

Tricky?

(bottom hole)

*It is to be so
in GeothermEx
w/ bottom hole.*

The Reservoir Verification Flow Tests (RVFT) of 1995 followed two years of shut-in, during which time the pressure on the reservoir was allowed to decay to 1,450 psi, then maintained at this level. The injection pump for the RVFT was a new, 218-stage high-pressure centrifugal pump, built by REDA and operated using the existing injection pump diesel motor.

The objectives of the RVFT were to: 1) ascertain the condition of the reservoir following the extended shut-in, especially with respect to the sudden impedance drop noted during the cyclic flow test on 6 or 13 May 1993; 2) demonstrate that steady-state operations could be re-established; and 3) further explore methods for maximizing productivity, by testing a load-following operation.

Results from the first phase of the RVFT (conducted at 1,400 psi back-pressure) showed a flow rate 17% higher than the stabilized flow at 1,400 psi before the 6 or 13 May 1993 impedance drop, corresponding to a retention of about half of the 35% increase which still existed at the end of the

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cyclic flow tests. Modal volume was 24% lower than previously measured; LANL speculated that this may have been a result of the increased flow rate, although other causes are possible.

The second phase of the RVFT (2,200 psi back-pressure) again showed a flow rate increase of 17% compared to previous flow at the same back-pressure during December 1992. Water loss was about 15%, considerably lower than the 27% measured previously at this pressure, and wellhead temperatures were higher, which is consistent with the higher flow rate.

During the RVFT, the annular leakage at injection well EE-3A increased from its prior levels of 2 - 6 gpm, and pressure increased in the second annular space of the well. A breach in the innermost casing string was subsequently identified at 4,150 feet. These leaks did not affect the flow tests.

The load-following experiment was then conducted from 3 to 9 July 1995 to simulate peak and off-peak operation of the system. For four hours on each of six consecutive days, the production well back-pressure was reduced, increasing the production rate and, consequently, the wellhead temperature. The sixth cycle yielded a peak flow rate of 147 gpm (which was higher than the injection rate) at a wellhead temperature of nearly 189°C, which is equivalent to 6.12 MW_t. The off-peak (baseload) production rate was 130 gpm at nearly 183°C or 3.72 MW_t. The average for the day was 4.11 MW_t.

The last test of the Phase II reservoir was a tracer test, in which sodium fluorescein and para-toluene sulfonic acid were injected. We assume that the operating conditions were similar to most of the tests undertaken at this time (injection and production wellhead pressures of 3,960 and 2,200 psi, respectively), because comparisons were made with previous results under these conditions; however, this is not specifically stated in the available documents. As compared to tracer tests run during the RVFT, modal volume decreased, integral mean volume increased, and

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less fluorescein was recovered. The conclusions from this test are presented in the following section of this report.

The results of the Phase II flow tests have not been fully analyzed, particularly with respect to the potential connection to the Phase I reservoir and the changes in the behavior of the Phase II reservoir which resulted from the pressure stimulation and cyclic flow tests. The main conclusions made to date are discussed in the following section.

4.2.6 Lessons Learned

The broader lessons learned about the Fenton Hill Phase II reservoir from flow and tracer testing involve evaluations of: 1) system behavior; 2) the nature of the Phase II reservoir; 3) changes in flow impedance; 4) heat-transfer; 5) microseismicity; 6) water losses; and 7) the impact of cyclic operation on the reservoir. These are summarized below.

1) System Behavior

The plant/system, which was controlled by an IBM PC, operated reliably with almost no human intervention. Automatic system shut-downs (including well shut-ins), caused mostly by lightning strikes, were flawless, and there were few maintenance problems. The pump failures during the first phase of the LTFT were fundamentally unrelated to the geothermal application, and there were no other substantial failures.

The concentration of TDS in circulating water stabilized at 3,000 - 4,000 ppm, and pH stabilized at 5-6. Total dissolved gases, consisting almost entirely of CO₂, stabilized at levels lower than 3,000 ppm. The concentration of H₂S was less than 1 ppm. Chemical geothermometers (silica, Na-K-Ca) agreed generally with the measured 240°C reservoir temperature. There was no significant

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corrosion, including within the casing of the injection well. There were virtually no emissions except for heat wasted to the atmosphere during normal flow operations; the dissolved gas level was so low that it was not necessary to separate and vent the gas to avoid break-out.

Thermally stable production was achieved, at an energy production rate of 4 MWt (first and second LTFT phases). The thermal energy equivalent of fuel and electricity consumed in running the plant was about 15% of the total energy produced.

2) Nature of the Reservoir

In their pre-exploitation state, before drilling and fracturing, the joint systems in the Phase II reservoir were completely sealed at depths below those corresponding to crustal temperatures of about 200°C. When the jointed rock mass was internally pressurized by pumping from the surface, one or more of the joints favorably oriented with respect to the direction of least principal stress began to open. As greater pressure was applied, these joints were progressively opened and extended, and other joint sets opened, creating a network of intersecting fractures. However, the rock mass beyond the slowly expanding periphery of the pressurized region remained well sealed, as indicated by the low overall fluid losses. Thus, the reservoir system was comprised of natural, pre-existing joints that were opened and propped by fluid pressure. The contemporary stress field dictates the conditions under which these joints (which formed under different stress conditions) will open upon pressurization.

LANL's analysis of injection, pressure decay and circulation tests indicates that the Phase II reservoir is made up of at least three separate sets of joints which have opening pressures of 15.0, 22.4 and 27.5 MPa (2,175, 3,250 and 3,990 psi), respectively. As the pressure in the reservoir is slowly increased, the joints first start to pressure-dilate while most of the asperities are still in

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contact. Then, at the specified opening pressure, the joint surfaces actually separate. The same phenomenon occurs in reverse during slow reservoir pressure decay; the decay curves show inflection points at the respective joint-closing pressures. It is inferred that the joints that required highest pressure to open were crucial to establishing the circulating system between injection and production. LANL refers to these as "manifolding joints".

The ratio of reservoir fluid volume (determined from flow and tracer data) to seismically active rock volume (determined from microseismic data) was on the order of 10^{-4} . Within the body of the HDR reservoir, fluid was stored primarily in joints that were dilated by fluid pressures that were well above the least principal earth stress. Therefore, the main component of the reservoir fluid storage arose from the elastic compression of the rock blocks between pressurized joints. The deformation of the reservoir region was only minimally influenced by the mechanical characteristics of the rock blocks themselves, which appear to be very stiff (very high bulk modulus) and to compress in a linearly elastic fashion.

3) Flow Impedance

Since the multiply interconnected joints within the reservoir were held open by fluid pressure (pressure propping), maintaining a higher mean reservoir pressure should increase productivity in the Phase II reservoir without compromising the distributed nature of flow.

The pressure gradient across most of the reservoir was reasonably gentle. However, in a region approximately 30 feet in radius surrounding the fluid entry zones of the production well, the pressure gradient increased markedly as pressure dropped to the imposed pressure in the wellbore. This was because joints were progressively more tightly closed, following the pressure gradient between the reservoir and the production well.

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Because of this, reservoir flow impedance was highest in the near-wellbore region surrounding the production well. Results of load-following tests in 1995 that supported this conclusion included a rapid increase of production WHP but a slow decrease of injection WHP on shut-in. This "concentration" of impedance near the production well led LANL to conclude that the distance between injection and production wells could be increased and the body of the reservoir enlarged with only a marginal increase in the overall reservoir impedance.

4) Heat-Transfer and Flow Dispersion

Contact between the circulating fluid and hot rock increased with time. Downhole temperature and tracer data both indicate that the flow through the reservoir, rather than concentrating in a few potential direct flow paths, progressively shifted towards more indirect flow paths as the test proceeded. Results of testing in 1992-93 that supported this conclusion included: 1) progressively longer tracer first arrival times (3.5 hours in April 1992 to 5 hours in April 1993); 2) progressively longer tracer peak times; 3) the identification of four production intervals from downhole temperature logs; and 4) constant total flow temperature above the uppermost production interval in spite of cooling at the lowermost, implying choking of lowermost and higher flow from others.

LANL has concluded that this self-regulating mechanism may be related to the temperature dependence of the viscosity of water. As certain flow paths get cooled, viscosity (and therefore impedance) increases and flow tends to get re-directed towards hotter, lower impedance paths. The fluid residence time of the shortest flow paths increased during flow testing with a general dispersion of flow into longer residence-time paths. First-arrival volumes and residence-time distribution (*i.e.*, the broadness of the tracer return peak) also increased with heat extraction. Tracer testing showed that as the level of reservoir pressure was increased, the flow paths for the

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circulating fluid tended to become more dispersed, thermal sweep efficiency was improved, the tendency for flow to short-circuit was reduced, and the overall impedance to flow was reduced.

Despite the stable production temperatures during the LTFT, LANL declined to make long-term projections of temperature because the effective reservoir volume and joint spacing for heat transfer were unknown (Brown, 1994). Some predictions of long-term reservoir temperature behavior were made, however, by numerical modeling undertaken after completion of the ICFT.

5) Microseismicity

As the HDR reservoir was being formed and then extended by the injection of high-pressure water, microseismic signals were generated predominantly by shear slippage along joints that were not aligned with the contemporary stress field. These microearthquakes occurred along all the joint sets with opening pressures up to and including that of the manifolding joints. However, joints within the stimulated region that were oriented almost orthogonally to the direction of least principal earth stress should open with very little if any shear displacement, and would not be seen in the microseismic data. It was concluded, therefore, that the absence of microearthquakes does not preclude the presence of flow paths for pressurized water.

The reservoir was generally aseismic during the LTFT, except for several periods late in the flow testing when the production well was shut in for extended periods of time, allowing the pressure in the northern part of the reservoir to build up to levels somewhat higher than the 3,500 to 3,600 psi previously observed to cause fracture extension in this portion of the reservoir. It was noted that injection can de-stress a reservoir region around the wellbore, so that on subsequent injection the same region is seismically quiet until the region is inflated and microseismic activity begins at the margins.

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Brown (1995b) also concluded that the seismic volume (determined from microseismic event locations) of the Phase II reservoir was directly proportional to the volume of fluid injected, suggesting that larger HDR reservoirs could be created by pumping at high pressures for longer periods of time. The seismic volume of the Phase II reservoir was about 130 million m³ (or about 4.6 billion cubic feet).

6) Water Losses

At normal operating pressures (3,960 psi at the injection wellhead and 1,400 psi at the production wellhead), water consumption was low and declined continuously. The loss rate of 12% of injected volume measured during the first phase of the LTFT in July 1992 declined to 7% during the second phase of the LTFT in April 1993. These low fluid losses are considered to have resulted from the tight sealing of the rock mass beyond the periphery of the pressurized region of the reservoir. It is postulated that, in the EE-3A/EE-2A system, most water loss occurred in the southern portion of the reservoir, which was defined by seismicity during the ICFT in 1986 (which used the EE-3A/EE-2 system), but was "inaccessible" during later testing.

LANL has concluded that lower water losses could be expected from a system with one injector and several producers, because such a system could operate at lower average reservoir pressure. However, as the Phase II tests have shown, it is more favorable to operate the Phase II reservoir with (at least periodic) high back-pressure; therefore, operating at a lower average reservoir pressure may not yield the optimum heat-transfer. It is likely that water losses would be lower with more than one production well, as a larger part of the stimulated volume would be active in both the heat-transfer and hydraulic sense.

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7) Cyclic Operations and Load Following

The cyclic flow test of May 1993 and the RVFT load-following experiment in 1995 showed that a meaningful overall enhancement in the reservoir performance, when compared to pre-existing steady-state levels, could be achieved by operating in a cyclic mode. Temperature cycles in the production well were about 10°C; these should have a minimal impact on the integrity of the production casing and surface pipe.

4.2.7 Technology Developed and Transferred

Throughout the Fenton Hill project, techniques for evaluating test procedures and results were developed and refined. Progress was made in the areas of tracer development, tracer test analysis, incorporation of tracer test results into numerical models of the reservoir, chemical modeling, and improved numerical models of heat transfer and fluid flow. Tracer test analysis and chemical modeling are discussed briefly below. Numerical modeling is discussed in Chapter 5.

There was also a considerable amount of experimental laboratory work on rock mechanics and mineralogical studies; however, these are not discussed in detail here because they do not relate directly to the analysis of flow and tracer test data. A possible exception is a series of water-rock interaction experiments that were conducted to study the possible deleterious effects of high pressures and temperatures on transmissivity, with the specific objective of determining if long-term shut-in might lead to sealing of fractures. This work was undertaken in 1988 and 1989, during the interval between the ICFT and the LTFT.

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1) Tracer Developments

In 1982, the finite-element heat-and-mass transfer code (FEHM) was modified to solve the convective-diffusion equation, thus enabling it to be used to calculate tracer breakthrough curves.

From 1982 through 1989, there was continued work on reactive tracer identification, characterization and methods of analysis at very low concentrations, as by high-pressure liquid chromatography (*e.g.*, Birdsell and Robinson, 1989). In addition, a program (tracer_reduce) was developed to reduce tracer return data from separate tests to common, comparable parameters.

A heat-transfer model based on tracer data (HDR-HEAT) was developed in 1987. This was a theoretical model that used a tracer-determined residence-time distribution and estimates of fracture porosity (the void volume in open fractures and dilated joints) to predict the long-term thermal drawdown performance of an HDR reservoir. Results indicated a large range of possible thermal responses; therefore, LANL realized the need to develop better *in-situ* tests to determine fracture porosity and the rock volume in a circulating HDR system.

The transport of a non-reactive tracer through fractures with two-dimensional flow was modeled in 1982 using the TEACH program. Between 1982 and 1985, two techniques were developed for modeling chemically reactive tracers to measure reservoir temperature distribution. One model used quartz dissolution into water: dissolved silica would be measured in water that was injected into the shut-in reservoir, then produced back (to the injection well) after a set period of time. The second model used a hypothetical tracer with known thermal decay rate, injected into the normally circulating reservoir system and sampled at the production well. Three situations were considered: 1) single-fracture flow; 2) multiple-discrete fractures flow; and 3) multiple-connected-fractures flow. These reactive tracer modeling studies were extended (as were non-reactive tracer studies)

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to develop methods of using the "tail" of a return curve to reveal information about reservoir heat-transfer area.

In 1992, HDR-HEAT, described above, was used to make predictions of long-term thermal drawdown in the Phase II reservoir.

2) Chemical Modeling

Modeling of the chemistry of produced fluids using the pore-fluid displacement model that was already under development continued during Phase II (from 1981 through 1993). Modeling of the behavior of silica was included in 1982, and in 1987 a new geochemical equilibrium model was developed, to include a larger number of equilibria.

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5. RESERVOIR ASSESSMENT

5.1 Introduction

Many tools and techniques were developed and modified under the auspices of the Fenton Hill HDR program. Here we concentrate on those likely to have application for future developers of EGS: well logging and downhole tools, fracture mapping using seismic techniques, and reservoir modeling.

5.2 Well Logging and Downhole Tools

For a complete description of the tools developed in the program, the reader is referred to the reports by Dennis *et al.* (1985) and Smith (1985), which include a great deal of information about the development process, specifications and use of the tools. The more important tools and related equipment developed either by Los Alamos or by commercial manufacturers for the Fenton Hill project include:

- high temperature cable heads and seals for the logging tools;
- seals and insulation for the downhole cable (wireline);
- an instrumentation and data acquisition system for well logging, designed and installed in a logging truck;
- a tool for releasing tracers or other chemicals downhole, with a gamma detector;
- a downhole water sampler;

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- high-temperature temperature logging tools;
- a six-arm caliper tool;
- a flowmeter (spinner) tool;
- a borehole acoustic televiewer;
- geophones and accelerometers in packages suitable for downhole deployment;
- methods to orient the geophones to record signals from fracturing operations;
- a mechanical device to generate acoustic signals downhole (wallbanger)
- various tools to explode charges downhole, including an acoustic source detonator, a string shot tool, a drill pipe severing tool, a fracture initiating tool and an explosive side-tracking device;
- downhole tools of smaller than normal diameter;
- a dewar system to keep electronics cool in tools;
- an acoustic transceiver system (which generates a signal in one wellbore and receives it in the other, for generating a "cross-hole acoustic scan" that can be analyzed to determine acoustic velocities and attenuation and elastic moduli);

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- mud motors and a turbodrill for directional drilling; and
- directional survey tools that can operate at high temperatures.

It is highly likely that many of the commercial manufacturers used the requirements of the Fenton Hill project as an opportunity to improve their tools for use at high temperatures, enabling them to be used more widely in geothermal applications. Before this time, the number of downhole tools that could operate at temperatures typical in geothermal systems was limited. Some of the tools commonly used by the geothermal industry today are undoubtedly products of this process. The downhole geophone package developed by Los Alamos is being used to monitor seismicity at various locations, including The Geysers.

5.3 Fracture Mapping and Seismological Analysis

5.3.1 Background

Seismic information, originating either from microearthquakes induced by injection (passive investigation), or from charges detonated in boreholes to create seismic events (active investigation), constitutes one of the most important sources of data for interpreting the reservoir in an HDR system, because it is the only means by which specific (rather than bulk) features away from the immediate environment of the borehole can be observed. Implementation of adequate methods for seismic monitoring and interpretation is therefore a critical part of the HDR experimentation process.

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The different aspects of seismological investigation, including instrumentation, monitoring and data collection methods, data processing, and analysis evolved considerably during the course of the Fenton Hill experiments. Monitoring of microearthquakes during hydraulic fracturing experiments and flow tests was carried out routinely, but the procedures used in the latest experiments were quite different from those in the earliest. Active methods were applied less frequently but still provided important results. By undertaking a sustained investigation spanning numerous experiments, the Fenton Hill project played a major part in developing the theory, field techniques and analytical methods that now are commonly accepted as part of HDR investigations, as summarized by Wohlenberg and Keppler (1982) and Niitsuma *et al.* (1998).

5.3.2 Passive Seismic Observation Techniques

The most basic purpose for passive seismic monitoring has been, and remains, to locate the sources (hypocenters) of the induced microearthquakes, on the assumption that structural features (pre-existing faults and joints, or induced fractures) become seismically active in response to pressurization or fluid movement. Event location has therefore been an integral part of the experiments where microearthquakes have been detected. The positions of events, and their clustering in space and time (or, conversely, their absence within particular zones or periods) is used to make inferences about the geometry and behavior of the HDR reservoir. Uncertainties or errors in location (which may arise from limited instrumentation, instrument insensitivity or failure, incomplete knowledge of the seismic velocity structure within the monitoring volume, a variety of noise effects, or limitations in processing and analysis) reduce the possibilities for making inferences about the reservoir.

Beyond the information provided by the locations and frequency of events, the arrival times, relative magnitudes and waveform characteristics of detected microearthquakes can provide

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additional insight into aspects of the reservoir such as source mechanisms and geometries, and the physical properties of the aseismic parts of the system. This can also provide information that is useful for refining and improving the event location process. Detailed analysis of this type is cumbersome, and so its application has been more restricted than has event location.

From the start of the HDR program, investigators recognized the need to use downhole seismometers (often referred to as geophones or sondes) to adequately detect and characterize induced microearthquakes, because surface seismometer stations are affected too much by noise, and by attenuation of signals passing through less competent near-surface rocks, to detect a useful number of events. In almost all of the Phase I and some of the Phase II experiments, a single three-component geophone installed in one of the wells was used for event detection and recording. The use of a multi-component tool allows discrimination of the components of the detected seismic waves in three dimensions, which in turn permits the use of the hodogram method for event location. The hodogram method uses the deduced polarization of the P-wave (compressional wave) of the microearthquake to determine the direction to the source; the distance is determined by comparison of the P-wave and S-wave (shear wave) arrival times.

The hodogram method of location is of limited accuracy, primarily because of uncertainties in the determination of source directions. Nevertheless, it was applied successfully for tracing reservoir development in the earlier experiments, and to make important inferences about reservoir processes. For example, Albright and Pearson (1982) identified a near-vertical zone of fracturing and tracked its propagation with time during hydraulic fracturing experiments; they also used the event location data to infer that the microearthquakes were triggered by changes in pore pressure (rather than thermal changes), and to estimate reservoir permeability based on inferred pressure diffusion rates. Keppler *et al.* (1983) describe how event locations were used in a series of experiments to track the development and propagation of distinct reservoir zones, with more rapid

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processing and interpretation of results allowing something close to real-time monitoring that can be used to guide as well as observe the progress of experiments.

More sophisticated determination and use of event location data became possible with the use of multiple geophones located in different wells, which allows microearthquakes to be located by inversion of arrival times, with improved accuracy. The most notable early use of this technique was in the Massive Hydraulic Fracturing of well EE-2 (Experiment 2032), for which three three-component geophones and two vertical-component geophones were installed in wells (House *et al.*, 1985). Using the data from this experiment, the growth of the seismic volume was tracked to determine the nature of reservoir growth. It was noted that the geometry of the seismic volume differed from that determined in previous experiments; this difference was attributed at least partially to the imprecision of the hodogram method. Inversion-method results were also compared with locations calculated by a "partial double-tool hodogram" (PDH) method, which used data from two geophones to refine hodogram location estimates; the PDH results were similar, though not identical, to the inversion results (House *et al.*, 1985).

Further studies based on data from Experiment 2032 and later experiments resulted in the development and application of a "tomographic imaging" or seismic imaging method, in which microearthquake arrival times are used in a joint hypocenter-velocity inversion to simultaneously determine both event locations and the three-dimensional P-wave and S-wave velocity structure of the region of the events (Fehler *et al.*, 1991; Block *et al.*, 1994). The determination of velocity structure improves the accuracy of calculated locations compared with those determined using a constant-velocity model, and it also provides useful information for making inferences about reservoir characteristics. Block *et al.* (1994) estimated a 35-40% improvement in location accuracy, and concluded that the method gives realistic estimates of velocity within and near the reservoir zone. It should be noted, though, that the application of this methodology required

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imposing a number of assumptions or constraints on the calculation process; as a result, the technique is complex and probably open to extensive refinement.

Discrimination of specific spatial features (typically, planar features interpreted to be seismically active fractures) within the seismic "cloud" of event locations is an important part of characterizing the geometry and nature of the reservoir. Techniques for identifying and locating planes were developed and refined as the event locations themselves were becoming more accurate. Visual inspection of plotted data to find planar features was used during many studies, but was later augmented by statistical methods including, importantly, the three-point method, which relies on calculation of all possible planes (defined by sets of three event locations) within a defined volume to identify the orientations that occur with statistically significant frequency (Fehler *et al.*, 1997; Dreesen *et al.*, 1987; Fehler, 1989). This technique was applied to data from Experiment 2032 to identify five significant planar orientations in the reservoir (Fehler *et al.*, 1987). Fractures identified in the experiment were used to assess likely flow paths, and were correlated with fluid loss zones and other features identified by borehole logging (Dreesen *et al.*, 1987). In later experiments, fracture planes identified by the three-point method were compared with independent estimates of the stress field in the project area, and found to coincide with orientations that stress models would predict (Fehler, 1989).

Other statistical methods were used for identifying planar features, including "collapsing", doublet analysis (based on waveform comparisons) and cluster analysis (Niitsuma *et al.*, 1998). An analysis of data from Experiment 2032 used both cluster analysis and identification of characteristic waveforms from specific source regions to define seismically active fractures with unusual precision (Phillips *et al.*, 1997). In this study, the observation that the event clusters on the identified planes had sharp terminations led to interpretation of the orientation and location of

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aseismic joints; this represents a potentially important step in further characterizing flow paths in the reservoir.

Continued improvements in instrumentation and data collection allowed the latest experiments to benefit from approximately real-time monitoring of microearthquakes. In the Initial Closed-Loop Flow Test (ICFT) and in other late experiments, a MASSCOMP digital data acquisition system was used, with favorable results (Dash *et al.*, 1989). Results of seismic monitoring in these experiments were used to assess water losses during flow testing (Brown and Fehler, 1989), to assess reservoir behavior, and to monitor for larger earthquakes that might constitute an environmental impact (Dash *et al.*, 1989).

As noted, seismic data collected during the HDR experiments provide information beyond that needed for tracking microearthquakes in space and time. Evidence such as waveform characteristics and S-wave and P-wave relative behaviors permit important inferences to be made about earthquake source mechanisms and other characteristics of the reservoir region. For example, it was observed in the earliest experiments that the relative strength of S-waves required that the predominant mechanism generating the seismic signals was shear slip, rather than extensional or tensile fracturing (Wohlenberg and Keppler, 1987; Albright and Pearson, 1982). Calculation of fracture-plane solutions from data recorded at surface seismometers (a standard practice in seismological studies) was performed in several experiments, in an effort to determine slip orientations (House *et al.*, 1985; Fehler *et al.*, 1987). However, the results did not exhibit a strong correlation with results of stress field analyses and other studies.

The occurrence of long-period seismic events, similar to those originating from certain volcanic processes, has been observed and studied in an effort to characterize source mechanisms (Ferrazzini *et al.*, 1990; Fehler and Bame, 1985). Studies of data from Experiments 2018 and 2023

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used waveform analysis to examine and classify these events, and it was concluded, based on theoretical models, that the events are probably caused by either the tensile extension of a fluid-filled fracture, or the sudden opening to fluid movement of a closed channel. Estimates of fracture dimensions were made from the theoretical considerations (Fehler and Bame, 1985). Waveform analysis was also applied to tectonic (fault-slip) events to make estimates of source radius, average slip and stress drop (Fehler and Bame, 1985).

Waveform stacking techniques have been applied to selected data sets or subsets to investigate particular reservoir characteristics. Fehler *et al.* (1991) investigated several such techniques for the purpose of determining seismic velocities in selected reservoir sub-volumes, to identify significant fractures by unique waveform signatures, and to examine seismic scattering by fractures. Phillips *et al.* (1997) used "slant stacking" in an attempt to investigate scattering by determining the direction in which energy was exiting individual fractures.

The studies related to monitoring of induced microearthquakes are quite varied and show progressive refinement and innovation in the techniques used for instrumentation, data collection and processing, and analysis of results. Processing of seismic data is time-consuming, and it appears that, as a result, the most sophisticated techniques developed were applied only to selected sets of data, and that some data sets may remain incompletely analyzed in terms of the methodology available at the conclusion of the project. Nevertheless, the collection and analysis of seismic data provided important advances both in understanding the development and nature of the Fenton Hill reservoir, and in the development of techniques of general use in EGS technology.

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5.3.3 Active Seismic Observation Techniques

The passive seismic monitoring described above made up the bulk of the seismological studies conducted in the Fenton Hill project. Active seismic techniques were applied most frequently for determination of average or characteristic seismic velocities within the monitoring volume, for use in calculating induced microearthquake locations. In these instances, a limited number of downhole charges would be fired in a borehole, observing arrival times in an instrumented well.

Several experiments using active techniques were conducted specifically to investigate a variety of reservoir properties. An important example of these is the series of "shear shadowing" experiments conducted during the Phase I reservoir program (Aki *et al.*, 1982). In these experiments, downhole shots were fired repeatedly, with the system both unpressurized and pressurized, while monitoring in a single instrumented well. By comparing the pressurized and unpressurized results the investigators inferred that the granite/gneiss contact in the reservoir zone was creating reflections in a manner consistent with the behavior of a fluid-filled fracture. Similar experiments, conducted using a piezometric transducer set at various downhole locations as the energy source, were used to identify a planar feature, and to estimate the minimum open area of a fracture corresponding to such a feature. Further analysis of the results led to the inference that the zone identified must consist of multiple, fairly "clean" fractures spread over a three-dimensional volume, rather than a single fracture.

Other active seismic studies conducted during the Phase I reservoir program included a number of acoustic ranging experiments, and similar experiments conducted using a "wallbanger." In the Phase II experiments, active seismic methods were seldom, if ever, applied.

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5.3.4 Identification of Potential Improvements

The seismological studies in the Fenton Hill project were useful in identifying the ways in which enhancements in monitoring equipment and the methodology for data collection, processing and analysis could be improved to be of greater use in the development of EGS systems. To a significant extent, attempts were made to address these identified needs as the work progressed; however, due to the complexity of the techniques and the information involved, there remains much opportunity for further improvement. Potential improvements indicated by the Fenton Hill results include:

- Improvements to downhole seismometers, for greater temperature tolerance, more reliable and sensitive response, and self-calibration capabilities. It should be noted, though, that seismometer limitations do not appear to have severely impeded adequate collection of data.
- Methods and equipment for more complete and accurate collection, organization and storage of data. Substantial improvements have been made in recording methods and event-detection systems, but, given the potential volume of data and the complexity of the information being collected, further improvements are likely to be of considerable value.
- Enhancements to data processing, particularly in the automation of routine but complex processing tasks, such as screening of data for quality, identification of arrival times, and discrimination and grouping of similar event waveforms. Even during the latest Fenton Hill studies, much of the data processing and analysis was essentially manual, limiting the coverage that could be achieved.

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- Continued improvement in the analytical techniques that have proven useful or promising, including techniques for determining event locations and velocity structure (especially the joint hypocenter determination methods), and analysis of waveform data, including those of long-period events, for specialized studies aimed at reservoir characterization.
- Development of methods for checking and calibrating the inferences made from seismic data. These can include techniques that investigate the same phenomena by multiple passive seismic analysis techniques based on independent types of data active seismic studies, and inferences made from borehole logging, reservoir engineering, or other areas of study.

In addition to these improvements, there are two more ways to increase the utility of the seismic data. First, baseline data should be collected for several weeks or months before fracturing or testing begins, and a test run of the data collection and storage system (perhaps using calibration shots or other detonations) should be made, enabling a level of familiarity with the system to be developed. Typically, this was not done prior to the fracturing and testing operations at Fenton Hill. Second, the data collection should be processed, analyzed, archived and documented immediately after completion of the work so that any problems with or corrections to the data can be resolved and not forgotten. Because this was not done for many of the Fenton Hill experiments, the database is particularly cumbersome and difficult to analyze by an outside party.

5.3.5 Technology Transfer

The results of the Fenton Hill seismological studies have contributed to HDR programs carried out by other investigators (Niitsuma *et al.*, 1998). In addition, the Fenton Hill investigators have applied their methodologies in oil and gas and hydrothermal development projects.

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At the Baca project area, near the Fenton Hill site, seismic monitoring was implemented in conjunction with a program of well stimulation by hydraulic fracturing (Pearson *et al.*, 1982). After velocity calibration, a single downhole three-component geophone was used to detect and locate microearthquake events during the stimulation of two wells. This effort successfully identified and estimated the dimensions of the zones of rock failure associated with the simulation.

More recently, a high-temperature geophone array was developed and installed in a well at The Geysers to investigate the potential for reducing microearthquake detection limits and improving the quality of data collection in an operating geothermal field (Albright *et al.*, 1998). The results of this investigation indicate that downhole monitoring can successfully detect events two to three orders of magnitude smaller than those detectable by surface stations. This results in an approximately 1,000-fold increase in the number of events detected, with a potentially greater information content per event. Further improvements in instrumentation are under development as part of the same investigation (Albright *et al.*, 1998).

5.4 Reservoir Modeling

5.4.1 Phase I

Much of the Phase I data analysis involved developing and using two different two-dimensional numerical simulation models for heat-transfer, each based on a different model reservoir geometry developed from drilling, fracturing and testing data.

The "independent fractures" model was developed first, when it was believed that the First Reservoir (before re-work and re-fracture of EE-1) consisted primarily of a single large fracture, and later that the Second Reservoir consisted of a new large fracture, along with the smaller first

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fracture and some cross-cutting joints (referred to as manifold fractures). Some defining characteristics of this model are:

- No thermal interaction was permitted between (two) independent fractures; therefore, the model was not able to realistically represent the effects of temperature gradients in the rock between fractures.
- The model provides a relatively realistic assessment of the effect of fluid dynamics and sweep efficiencies.
- The model was not able to detect any increase in the effective heat-transfer area during actual drawdown; therefore, matches to data assumed a constant heat-transfer area during any one Run Segment.

The "multiple fractures" model was developed later, when it was suspected that the reservoir could be represented more accurately by a series of parallel fractures that independently connected the two wells, but which would thermally interfere with each other. Some defining characteristics of this model are:

- Multiple fractures were partly independent, but there was thermal interaction between the fracture systems.
- Unlike the "independent fractures" model, this model was not able to realistically assess the effect of fluid dynamics and sweep efficiencies.

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- Matches to Run Segments 2, 3 and 5 were achieved assuming increasing heat-transfer area during the Run Segment.

Both models were able to simulate the overall thermal drawdown observed during the tests reasonably well, with somewhat different assumptions of heat transfer area (table 5.1). Following the convention used in the petroleum industry, heat transfer or fracture area refers to one side of the fracture only, so geometric fracture surface is twice the tabulated area. Although the "multiple fractures" model was sometimes presented in project publications as the more correct view, it is our understanding that neither model could be regarded as preferable in all aspects.

Near the end of Phase I, LANL developed the first version of its finite-element numerical simulator ("FEHM") for geothermal reservoirs. It is our understanding that this code was developed for the Fenton Hill project, but there was no mention of its use during Phase I in the available documents.

5.4.2 Phase II

Much computer modeling of the reservoir system was performed during Phase II, and numerous codes were developed, as follows.

1) FEHM

The finite-element heat-and-mass transfer code (FEHM) was modified in 1982 to solve the convective-diffusion equation, enabling it to calculate tracer breakthrough curves. FEHM was used in 1982 and 1983 to model chemically reactive tracers, allowing inferences to be made about reservoir temperature distribution. One model used quartz dissolution into water. In this model,

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dissolved silica would be measured in water that was injected into the shut-in reservoir, then produced back (to the injection well) after a set period of time. The second model used a theoretical tracer with known thermal decay rate, injected into the normally circulating reservoir system and sampled at the production well. Three situations were considered: single-fracture flow, multiple-discrete-fractures flow, and multiple-connected-fractures flow. These reactive tracer modeling studies were expanded in 1984, as were non-reactive tracer studies, undertaken to develop methods of using the "tail" of a return curve (late stage data collected when tracer concentration is low and continues to decline very slowly).

In 1984 and 1985, FEHM's solution scheme was improved to include double porosity with pressure-dependent fracture apertures. It was used extensively at this time to estimate the size of the reservoir created during hydraulic fracturing (particularly Experiment 2032), and comparisons were made with the reservoir size estimated from seismic data. New iterative solutions schemes were also added, and improvements in its ability to match tracer data were incorporated during 1986 - 1989.

In 1989, FEHM was used to match the transient pressure and tracer data from the ICFT, and a limited amount of modeling of the later Phase II flow test data was undertaken starting in 1992.

2) FRACNET

Between 1987 and 1990, a fractured reservoir discrete flow model (FRACNET) was developed to predict pressure-dependent flow in a jointed rock mass. Temperature is ignored in this model; fluid flow is coupled to rock and fracture deformation. Initially capable of modeling only steady-state flow, FRACNET was revised in 1990 to simulate transient flow, and was used to examine the

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effects of different proposed reservoir operating conditions and measures to reduce impedance, and tracer behavior.

In 1990, FRACNET was revised again to allow a network of fractures to be generated stochastically to capture the random nature of the joint systems. Furthermore, the new version allowed the homogeneous medium itself to be divided into discrete, finite-difference grid sections in which flow can occur, rather than simply a series of storage volumes connected to each fracture, with no permeability in between. This allows matrix storage and flow to be simulated. In 1991, this updated version of FRACNET was used to match wellhead pressure data from Experiment 2077.

3) HDR-HEAT

A heat-transfer model based on tracer data (HDR-HEAT) was developed in 1987. This was a theoretical model that used a tracer-determined residence-time distribution and estimates of fracture porosity (the void volume in open fractures and dilated joints) to predict the long-term thermal drawdown performance of an HDR reservoir. Results indicated a large range of possible thermal responses, and therefore highlighted the need to develop better *in-situ* tests to determine fracture porosity and the rock volume in a circulating HDR system. In 1992, HDR-HEAT was used to make predictions of thermal drawdown anticipated during the LTFT.

4) GEOCRACK

Beginning in 1990, modeling efforts focused on GEOCRACK, a finite-element model for geothermal reservoirs that fully couples rock mechanics, fluid flow and heat transfer. This code was developed at the University of Kansas with participation of LANL personnel. It has been

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increasingly applied to the Fenton Hill work as the principal reservoir model, and has been used to match flow and tracer test results since 1990.

GEOCRACK characterizes the apertures of flow paths as a nonlinear function of pressure, with the rate of flow proportional to the cube of the aperture size, but can only roughly simulate highly transient reservoir behavior like periodic (cyclic) pressure stimulation. Thus, it requires more refinement. Work is currently underway to develop a three-dimensional version of GEOCRACK.

5) Chemical Modeling

Modeling of the chemistry of the produced fluids using the pore-fluid displacement model that was already under development at the end of Phase I was continued in 1982. Modeling of silica behavior was included in 1982, and in 1987 a new geochemical equilibrium model was developed, to include a larger number of equilibria.

6) Semi-Analytical Modeling

Semi-analytical modeling of the 1992 flow test data (see table 4.2) was done before the 1995 RVFT, with the goal of developing a method to predict reservoir performance at higher injection and production pressures. The following is summarized from Brown (1994), who first assumed that:

1. flow through the fractured reservoir is predominantly laminar, with the rate of flow being proportional to the total pressure drop across the reservoir, ΔP , as measured at the reservoir inlet and outlet;

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2. flow rate is also a function of the mean reservoir pressure level raised to a power greater than one, and;
3. mean reservoir pressure is weighted toward the outlet side of the reservoir according to:

$$P_{\text{mean}} = (P_{\text{in}} + 2 * P_{\text{out}}) / 3 \quad (\text{eqn 1}).$$

Given these assumptions, it was possible to match the four distinct 1992 operating conditions, as follows:

1. Form: $Q = C(P_{\text{mean}})^a \Delta P$ (eqn 2),
where Q = gpm production, C = scaling constant, and a = exponent for mean pressure.
2. Fitted to data for the LTFT-first phase through the 2,200 psi back pressure test (four data points):

$$Q = 5.65 * 10^{-6} (P_{\text{mean}})^{1.1} \Delta P \quad (\text{eqn 3})$$

3. Percent errors, calculated to measured: -1.1 to +0.8.

This result was then used to make predictions of reservoir productivity and thermal recovery under the conditions that might exist if there were two production wells and one injection well. The leading assumptions were:

1. a second production well drilled to the presently "unavailable" southern part of the reservoir should, with no other operational changes, approximately double the reservoir productivity;

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2. the second well will allow a significant increase of injection pressure without inducing reservoir growth, because it will establish a pressure sink in this portion of the reservoir, and;
3. therefore, the ambient pressure level of the reservoir could also be significantly increased, further dilating the joint network that comprises the active reservoir flow system and thereby reducing the overall impedance to flow.

The specifically assumed conditions for a two production well system were, for each well:

Injection pressure	5,500 psi	Production pressure	2,000 psi
Buoyant drive	756 psi	Total reservoir ΔP	4,256 psi.

These conditions in equations 1 and 3 indicate a flow rate per well of 170.5 gpm, which is a relative increase of $(170.5/90.) = 1.90$ over the flow rate of 90 gpm observed during the LTFT first phase (table 4.2).

Considering the wellbore heat loss that occurred during the LTFT first phase, as determined from downhole temperature logs and the measure wellhead temperature, and assuming linear scaling between the conductive heat loss and flow rate, it followed that recoverable heat (enthalpy, in BTU/lb) at 170.5 gpm should be 1.16 times the recoverable heat at 90 gpm. The assumed heat rejection temperature was 54°C, and the predicted WHT at 170.5 gpm was 204°C.

Therefore, combining the relative increase of flow rate and the relative increase of recoverable heat per unit mass, the overall relative thermal productivity increase per well, with two production

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wells at the assumed operating conditions, is expected to be $(1.90 * 1.16) = 2.20$. The total relative increase for two wells is therefore $2 * 2.20 = 4.40$.

To translate this relative increase into the amount of thermal power that could be extracted from two production wells, Brown (1994) then assumed that conditions in May 1993 (table 4.2, post-cyclic flow) could be used as a base case.

First, because the injection pressure in May 1993 was 3,840 psi (compared to 3,960 psi during the LTFT first phase), the production flow rate of 121.1 gpm in May 1993 was scaled to flow at an injection of 130 gpm at 3,960 psi (using equations 1 and 3). The result was an expected production rate of 128.2 gpm from the one production well. For a flow rate of 128.2 gpm at 190.4°C (the temperature was assumed to be the same as measured at 121.1 gpm), with heat rejection at 54°C, it followed that thermal production was 4.6 MWt.

Brown (1994) then concluded that a two-production well system would give total thermal recovery of $4.4 * 4.6 = 20.2$ MWt (both wells). Since wellhead temperature would be closer to 204°C than 190.4°C, this estimate was regarded as conservative. Total flow from the two wells would be 340 gpm. The improvement over a one-production well system would be a factor of $(20.2/4.6) = 4.4$.

However, Brown's assumption for total thermal recovery multiplies a recovery factor for 170.5 gpm against a basis of 90 gpm times a recovery rate for 128.2 gpm, *i.e.*, it uses the overall formula $(170.5/90) * 1.16 * 2 * 4.6 = 20.2$. The correct factor for relative flow should be $(170.5/128.2)$, and the correct factor for recoverable heat at 170.5 gpm should also be scaled to a basis of 128.2 gpm, and would not be exactly 1.16. Assuming that 1.16 remains a satisfactory approximation: $(170.5/128.2) * 1.16 * 2 * 4.6 = 14.19$ MWt.

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An alternative, much more straightforward method of calculating total thermal recovery is to directly use the estimate of 170.5 gpm at a wellhead temperature of 204°C. With heat rejection at 54°C, the recovery is 6.9 MWt per well, or a combined total 13.8 MWt. Thus, the potential thermal recovery with two production wells is $(13.8/4.6) = 3.0$ times the recovery with only one production well.

5.4.3 Technology Transfer

FEHM, which currently has about 200 users, has been used widely overseas for HDR applications. GEOCRACK has been used to match flow test and tracer test data from Fenton Hill and is also used to evaluate data from overseas HDR projects. As far as we know, neither of these codes nor any of the other modeling techniques mentioned above has been used commercially for geothermal reservoir simulation in the U.S. This is because they are specialized to the task at hand: the prediction of HDR reservoir behavior. One exception to this is FEHM, which has wide application in the simulation of geothermal reservoir, groundwater and waste isolation problems.

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TABLES

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**Table 1.1: Former or Present LANL Personnel
Interviewed for the Peer Review**

<i>Name</i>	<i>Involvement with the Fenton Hill Project</i>
Jim Albright	Collection and interpretation of seismic data, particularly during Phase I
Don Brown	Development of concept; drilling and testing of wells and analysis of flow test data from Phase I and Phase II
Kerry Burns	Well log analysis and tool development (borehole televiewer)
Zora Dash	Interpretation of well log and well test data; heat transfer modeling; development and use of wellbore heat transfer code to support drilling operations
Burt Dennis	Logging tool development and data acquisition, including seismic data
Tom Dey	Studies of <i>in-situ</i> stress and rock mechanics
Don Dreesen	Drilling engineering; fracturing of Phase II wells
Dave Duchane	Project management
Mike Fehler	Collection and interpretation of seismic data from Phase II
Grant Heiken	Geological site evaluation; preparation of book on the history of the project
Leigh House	Collection and interpretation of seismic data from Phase II
Schoen Levy	Interpretation of lithology and petrology of Phase II reservoir rock
Bob Potter	Development of concept; evaluation of hydraulic fracturing, seismic, tracer and flow test data from Phase I and Phase II
Bruce Robinson	Evaluation of tracer data from Phase II
John Rowley	Drilling of wells EE-2 and EE-3 (Phase II)
Jim Rutledge	Collection and interpretation of seismic data from Phase II
Jim Thomson	Drilling engineering; design and operation of well test facilities for Phase II
George Zvoloski	Development and use of numerical and heat-transfer models

(i)

Table 4.1 : Phase I Flow and Tracer Testing (January 1978 - December 1980)
- Part A: Pressures and Flow Rates, Tracer Tests, Seismic Events

			Typical				Tracer Tests	Seismic Events	Comments	
Test	Dates	Duration	WHP (psi)		Flow (gpm)					
			Inject.	Prod.	Inject.	Prod.				
Part A: Tests in "First Reservoir"										
Run Segment 1	"precursor experiment"	Sept. 1977	4 days					none		
Run Segment 2	"75 day test"	Jan.28 - Apr.12, 1978	75 days	1280→ 860	160	135→ 250	115→ 250	4 Na-F	Immeasurably small	Four stages each with a different injection pressure, starting high and ending low. Flow rates increased (impedance dropped) throughout the test.
Run Segment 3	"High Back-Pressure Experiment" Exp.186	Sept.-Oct. 1978	28 days	1350	1400	170→ 200	120→ 150	3 Na-F		End of test operated at low backpressure. Bad casing cement in EE-1, upflow in annulus to 2500 ft
Re-work of well EE-1 (injector) - early 1979 Massive Hydraulic Fracturing (MHF) of well EE-1										
Part B: Tests in "Second Reservoir"										
Run Segment 4	"23 day test" Exp.215	Oct.23, 1979	<1 day?					none	Largest event magnitude -1.5	High-pressure hydraulic fracturing
	Flow Stages 1A, 1,2	Oct.23-27	5 days	2490	160	240	100	1 Na-F		Low back-pressure. Largest seismic event -3.
	Flow Stage 3	Oct.28-30	3 days	2490	1490	130	350	1 Na-F		High back-pressure
	Flow Stage 4	Oct.31-Nov.15	15 days	1350	160	120	100	2 Na-F		Steady-state low back-pressure. Largest seismic event -3.
Run Segment 5	Exp.217	Feb.26-Dec.8, 1980	286 days	1420→ 1230	190→ 160	115→ 90	100→ 80	1 Na-F, 4 ⁸² Br	13 events magnitude -1.5 to 0.5 (probably related to drilling EE-2 and -3)	Started with multi-step flow rate test of impedance. Decrease of injection WHP was due to pump impeller corrosion. A leak into the EE-1 annulus developed, starting about day 166. Only major perturbation during test: 9 day shut-in starting day 68.
Stress Unlocking Experiment ("SUE")		Dec.9-10, 1980	2 days	2180	2180	0	0	none	Signif. micro-activity in region of thermal depletion	Also listed as part of Run Segment 5. Goal: facilitate readjustment of reservoir rocks to new stress system generated by cooling. EE-1 annulus leak 24 - 59 gpm.
Post SUE flow		Dec.11-16 , 1980	6 days	1220	190	140	130	1 ⁸² Br		

Typical values are rounded to the nearest 10 psi, 5 gpm
 Arrow indicates overall trend during test

Na-F = sodium fluorescein
⁸²Br = NH₄ ⁸²Br (an irradiated ammonium bromide solution)

Table 4.1 : Phase I Flow and Tracer Testing (January 1978 - December 1980)
- Part B: Other Measurements

Test	Dates	Duration	Ave Heat Extracted MWt	Prod. ¹ WHT °C	Flow Impedance psi/gpm	Water Loss %	Tracer Modal Vol. m ³	Comments
Part A: Tests in "First Reservoir"								
Run Segment 1 "precursor experiment"	Sept. 1977	4 days						
Run Segment 2 "75 day test"	Jan.28 - Apr.12, 1978	75 days	3.1 - 4	175°→ 85°	15.6→ 3.0	decr.to <1%	11.4→ 26.5	Impedance nearly stable after 42 days. Tracer modal volume grew linearly with total energy extracted. Small water loss at end attributed to low injection pressure; loss projected to end of test from first 15 days is c. 7%.
Run Segment 3 "High Back-Pressure Experiment" Exp.186	Sept.-Oct. 1978	28 days	2.1	135°→ 99°	7.5→ 0.5	14% (at end)	3.8→ 20.8	Impedance nearly stable after 17 days. Nearly linear relationship between tracer modal volume increase and thermal energy extracted.
Re-work of well EE-1 (injector) - early 1979 Massive Hydraulic Fracturing (MHF) of well EE-1								
Part B: Tests in "Second Reservoir"								
Run Segment 4 "23 day test" Exp.215 Flow Stages 1A, 1,2 Flow Stage 3 Flow Stage 4	Oct.23, 1979	<1 day?						
	Oct.23-27	5 days					136 ± 19	
	Oct.28-30	3 days					144 ± 19	
	Oct.31-Nov.15	15 days	2.8	153° constant	18→ 17	na	125 ± 11	Impedance constant after two days. Last tracer test on Nov.12.
Run Segment 5 Exp.217	Feb.26-Dec.8, 1980	286 days	2.8	156° → 158° → 149°	15.5	10%	155→ 187	Highest wellhead temperature around day 60. Impedance, water loss represent steady state after initial decline. Impedance by Extended Muskat method: ave.14.3 psi/gpm (7 meas.), 73% of total is exit impedance. Linear relationship between tracer modal volume and total thermal energy extracted during test.
Stress Unlocking Experiment ("SUE")	Dec.9-10, 1980	2 days						Numerous seismic signals, concentrated in regions of reservoir most affected by thermal depletion.
Post SUE flow	Dec.11-16, 1980	6 days			8.2		266	Large increase of modal volume. Extended Muskat method: 55% of total impedance is exit impedance. Both entrance and exit impedance decrease 50% from Run Segment 5.

na = determination not applicable due to nature of data or test design

1: Injection WHT was near 25°C during all tests.

Table 4.2 : Phase II Flow and Tracer Testing (May 1986 - May 1993) and Reservoir Verification Testing (May - July 1995)
- Part A: Pressures and Flow Rates, Tracer Tests, Seismic Events

Test	Dates	Duration	Typical		Inject.	Prod.	Inject.	Prod.	Tracer Tests	Seismic Events	Comments
			WHP (psi)	Flow (gpm)							
Phase II Tests											
Initial Closed (ICFT) Exp.2067 Loop Flow Test	May 19-Jun.18, 1986	30 days	3900; 4500	500	168; 295	100→200	2 ¹²³ I	700 micro events, most at 5000 psi			Maximum injection rate 420 gpm; increase of production flow represents time required to inflate reservoir to pseudo steady-state volume. Partial collapse of EE-2 casing discovered after test. 2-3 gpm leak at EE-3A annulus.
EE-2 repairs and sidetrack as EE-2A: 1987-88											
Pre-LTFT reservoir pressure and venting tests: 1989-91											
Long Term Flow (LTFT - First Phase) Test - First Phase	Apr.8 - Jul.31, 1992	16 weeks	3960	1400	107	90	Na-F; p-TSA	aseismic			Data represent steady-state operations on Jul.21-29, 1992. Test ended with catastrophic injection pump failure.
Interim Flow Test (IFT)	Aug. - Sep. 1992	6 weeks	3240	1400	69	61					Data represent steady-state operations on Sep.29, 1992. Test used a limited-capacity reserve injection pump, which failed after 6 weeks.
1800 psi back-pressure test	Dec. 1992		3960	1800	113	91					Data represent steady-state operations on Dec.27, 1992. Test used a rented mud pump.
2200 psi back-pressure test	Dec. 1992		3960	2200	116	85					Data represent steady-state operations on Dec.10, 1992. Test used a rented mud pump.
Long Term Flow (LTFT - Second Phase) Test - Second Phase	Feb. - Apr. 1993	8 weeks	3965	1400	103	91	several				Test with new high-capacity injection pump. Data represent steady-state operations, Apr.12 - 15, 1993. Test terminated by exhaustion of funding.
Pressure stimulation test	Apr.15-17, 1993 (during LTFT)	3 days	3965	1400; periodic shut-ins.		90 (start); incr. each day					Production well shut-in for 25 min. at standard time on each of 3 consecutive days.
Cyclic flow tests	May 4-6, 1993	3 days	3965	1400; 3300-3400		90 (start); 145(d1); 145(d2); c. 200(d3)					Production backpressure increased for 16 hours/day each of 3 days. Prod. flow represents normal BP at start and each day after backpressure. Prod. flow at high BP was 30-40 gpm.
Post-cyclic flow	May 1993	12 days	3840	1400	128	121					Data represent May 13, 1993
Hiatus: 1993 - 1994 (2 yrs shut-in, pressure on reservoir decayed to 1450 psi, then maintained stable)											
Reservoir Verification Flow Tests (RVFT) - 1995											
RVFT Phase 1	May 10 - Jun.13, 1995	5 weeks	3960	1400	127	105	1 Na-F; 1 p-TSA				Data represent Jun.12, 1995. Tracer tests on Jun.6-9.
RVFT Phase 2	Jun.14 - 29, 1995	16 days	3960	2200	124	99	none				Data represent Jun.27-29, 1995. Prod WHP increased to 2200 psi in single step on May 13. Reservoir P distribution re-stabilized after 8 days.
Load-following experiment ("Cyclic flow tests")	Jul.3 - 9, 1995	6 days	3960	2200		starting: 97	none				Before Jul.3, backpressure had been steady-state 2200 psi for 18 days. Four hours each day reduce backpressure. Cycles 1-2 in production pressure control mode; cycles 3-6 in production flow control mode. Data represent peaking cycle, base load cycle, and 24-hr average of sixth (last) cycle.
				flow-control	peak: 129.3	peak: 146.6					
					base: 129.6	base: 92.4					
					ave: 129.6	ave: 101.6					
Final tracer test	Jul.11, 1995						1 Na-F; 1 p-TSA				

Typical values are rounded to the nearest
5 psi, 1 gpm
64→18 Arrow indicates overall trend during test

Na-F = sodium fluorescein
p-TSA = para-toluene sulfonic acid
¹²³I = iodide 123 in solution

Table 4.2 : Phase II Flow and Tracer Testing (May 1986 - May 1993) and Reservoir Verification Testing (May - July 1995)
- Part B: Other Measurements

Test	Dates	Duration	Ave Heat Extracted MWt	Prod. ¹ WHT °C	Flow Impedance psi/gpm	Water Loss %	Res. Pr. Drop ² psi	Tracer Modal Vol. m ³	Comments
Phase II Tests									
Initial Closed Loop Flow Test (ICFT) Exp.2067	May 19-Jun.18, 1986	30 days	incr. to 9-10	incr. to 192°	64→18	decr. to 33%		350	Downhole temperature in production well just above upper entry increased to 232°C. Tracer recoveries lower than in Phase I reservoir.
EE-2 repairs and sidetrack as EE-2A: 1987-88									
Pre-LTFT reservoir pressure and venting tests: 1989-91									
Long Term Flow Test - First Phase (LTFT - First Phase)	Apr.8 - Jul.31, 1992	16 weeks	4	183°		12%	3276	277→797	Data represent steady-state operations on Jul.21-29, 1992. WHT dropped 1°C during test (declining flow rate), but temperature constant at well inlet. Test ended with catastrophic injection pump failure.
Interim Flow Test (IFT)	Aug. - Sep. 1992	6 weeks		165°		5%	2608		
1800 psi back-pressure test	Dec. 1992			183°		19%	2873		
2200 psi back-pressure test	Dec. 1992			177°		27%	2448		
Long Term Flow Test - Second Phase (LTFT - Second Phase)	Feb. - Apr. 1993	8 weeks	4	184° (combined flow downhole: 228.1°)		7%		511	
Pressure stimulation test	Apr.15-17, 1993 (during LTFT)	3 days	Tot.daily energy prod. increased 1-2% each day.	increased slightly (higher flow rate)					Production well shut-in for 25 min. at standard time on each of 3 consecutive days.
Cyclic flow tests	May 4-6, 1993	3 days							
Post-cyclic flow	May 1993	12 days		190.4°		5%	3185		
Hiatus: 1993 - 1994 (2 yrs shut-in, pressure on reservoir decayed to 1450 psi, then maintained stable)									
Reservoir Verification Flow Tests (RVFT) - 1995									
RVFT Phase 1	May 10 - Jun.13, 1995	5 weeks		185°		17.5%		389	Data represent Jun.12, 1995
RVFT Phase 2	Jun.14 - 29, 1995	16 days		183° (combined flow downhole: 227°)		15%			Data represent Jun.27-29, 1995.
Load-following experiment ("Cyclic flow tests")	Jul.3 - 9, 1995	6 days		start: 182.7°					Entire WHT cycle covered range of 10.5°C
			peak: 6.12	peak: 188.7°					
			base: 3.72	base: 182.9°					
			ave: 4.11	ave: 183.9°		ave: 21.6%			
Final tracer test	Jul.11, 1995							357	Less Na-F recovery than in June test; p-TSA recovery unchanged.

1: Injection WHT was 18 - 19°C until cyclic flow tests (22°C)

Table 5.1 : Phase I Heat Transfer Modeling Results

		Heat Transfer Area, m ²			Comments
Test	Dates	Independent Fractures Model	Multiple Fractures Model		
			Initial Area	Final Area	
Part A: Tests in "First Reservoir"					
Run Segment 1 "precursor experiment"	Sept. 1977				
Run Segment 2 "75 day test"	Jan.28 - Apr.12, 1978	7500 - 8500	7500 - 8500	15000	
Run Segment 3 "High Back-Pressure Experiment" Exp.186	Sept.-Oct. 1978	8000	6000	12000	Lower initial area from multiple fractures model attributed to fluid dynamic short-circuiting at high back-pressure.
Re-work of well EE-1 (injector) - early 1979 Massive Hydraulic Fracturing (MHF) of well EE-1					
Part B: Tests in "Second Reservoir"					
Run Segment 4 "23 day test" Exp.215 Flow Stages 1A, 1,2 Flow Stage 3 Flow Stage 4	Oct.23, 1979				Not possible to distinguish effects of MHF from effects of the Run. The 45000 m2 estimate is a sum of 15000 m2 in the First reservoir, increased from 8000 m2 by thermal stress cracking, and 30000 m2 in the new Second reservoir fracture.
	Oct.23-27				
	Oct.28-30				
	Oct.31-Nov.15	45000	uncertain	21000 - 25000	
Run Segment 5 Exp.217	Feb.26-Dec.8, 1980	50000	25000	>45000	
Stress Unlocking Experiment ("SUE")	Dec.9-10, 1980				
Post SUE flow	Dec.11-16 , 1980				

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FIGURES

Figure 2.1 : Location of Valles Caldera, Barley Canyon and Fenton Hill

Figure 2.2: Location of shallow and intermediate gradient holes drilled by LANL around the Valles Caldera (from Smith, 1995)
Numbered circles indicate shallow heat-flow holes. Letters represent intermediate-depth heat-flow holes.

LEGEND

- HDR well
- △ Intermediate-depth heat flow hole
- Shallow heat flow hole
- Spring
- 8200— Elevation contour, feet (interval 200 ft.)

Figure 2.3: Location of the first deep exploration well (GT-1)

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PLOTDATE: 16OCT98	DRAWN: RRS	APP: ART
FILE: FHL_F23.DWG	FENTON.SS	P2056

LEGEND

- HDR well
- △ Intermediate-depth heat flow hole
- Shallow heat flow hole
- Spring
- Deviated well trace
- Reference elevation (thousands of feet, msl)
- Bottomhole location
- Elevation contour, feet (interval 200 ft.)

Figure 2.4: Location of the Phase I wells (GT-2 and EE-1)

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FILE: FH\F24.DWG FENTON.SS P2056

LEGEND

- HDR well
- △ Intermediate-depth heat flow hole
- Shallow heat flow hole
- Spring
- 8200— Elevation contour, feet (interval 200 ft.)
- Deviated well trace
- Reference elevation (thousands of feet, msl)
- Bottomhole location

Figure 2.5: Location of the Phase II wells (EE-2 and EE-3)

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APP: ART

FILE: FH_F25.DWG

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P2056

LEGEND

● HDR well

Deviated well trace
Reference elevation
(thousands of feet, msl)
Bottomhole location

-8600-

Elevation contour,
feet (interval 200 ft.)

Figure 2.6: Locations and subsurface courses of HDR wells at Fenton Hill

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FILE: DETAIL.DWG	FENTON.SS	P2056

Figure 4.1: A flow diagram of the Fenton Hill HDR surface plant (Duchane, 1993)