CHAPTER 4

Review of EGS and Related Technology – Status and Achievements

4.1 Scope and Organization

This chapter reviews several major international Enhanced Geothermal Systems (EGS) R&D field projects, which have focused on demonstrating the feasibility of mining heat by stimulating and operating an engineered reservoir. Our rationale for covering these projects is twofold: first, to provide historical context on how the technology has progressed, as a result of public and private R&D support; and, second, to chronicle the lessons learned from these efforts, particularly as they impact our understanding of how subsurface geologic conditions influence the creation and performance of EGS. Later, in Chapter 5, we develop a general approach to designing and stimulating EGS systems, which is largely based on the body of information created by these important experiments.

The remaining sections of this chapter are organized as follows: First, we provide a brief overview of the collective field effort, and then we cover each major project with a description of what was done and accomplished, as well as the "lessons learned" from each site. The major projects discussed include: Fenton Hill, in the United States; Rosemanowes, in the United Kingdom; Soultz, in France; Cooper Basin, in Australia; and Hijiori and Ogachi, in Japan – plus several other smaller projects. At the end of the chapter, we summarize the general state of understanding of EGS reservoir technologies, as well as the remaining needs for commercial-scale operations.

4.2 Overview

Field efforts began with the pioneering work of scientists at Los Alamos National Laboratory in the early 1970s at the Fenton Hill, New Mexico, site. In the early years, the program was referred to as the Hot Dry Rock or HDR project. Later, this was replaced by Enhanced/Engineered Geothermal Systems (EGS) to more correctly reflect the continuum of grade (or quality of resource) that exists among today's commercial hydrothermal systems, the unproductive margins of hydrothermal regions, and mid- to low-geothermal gradient regions throughout the United States.

The history of the worldwide effort to extract the Earth's heat from rocks that do not have pre-existing high permeability began with the Fenton Hill hot dry rock experiments. This first project was initially funded completely by the U.S. government, but later involved active collaborations under an International Energy Agency agreement with Great Britain, France, Germany, and Japan – the latter two countries providing funding ($5 million) to help support the research over a six-year period. The objective of the project was to develop a heat-extraction system in a high-temperature-gradient area with a large volume of uniform, low-permeability, crystalline basement rock on the margin of a hydrothermal system in the Valles Caldera region of New Mexico.

Building on the experience and data from the Fenton Hill project, the Rosemanowes, Hijiori, Ogachi, and Soultz projects attempted to develop further the concept of creating a reservoir in crystalline rock in other geological settings. These EGS/HDR field experiments were carried out starting about 1975 in the United Kingdom, and somewhat later in Japan, France, Sweden, and the Federal Republic of Germany (see timeline in Figure 4.1).

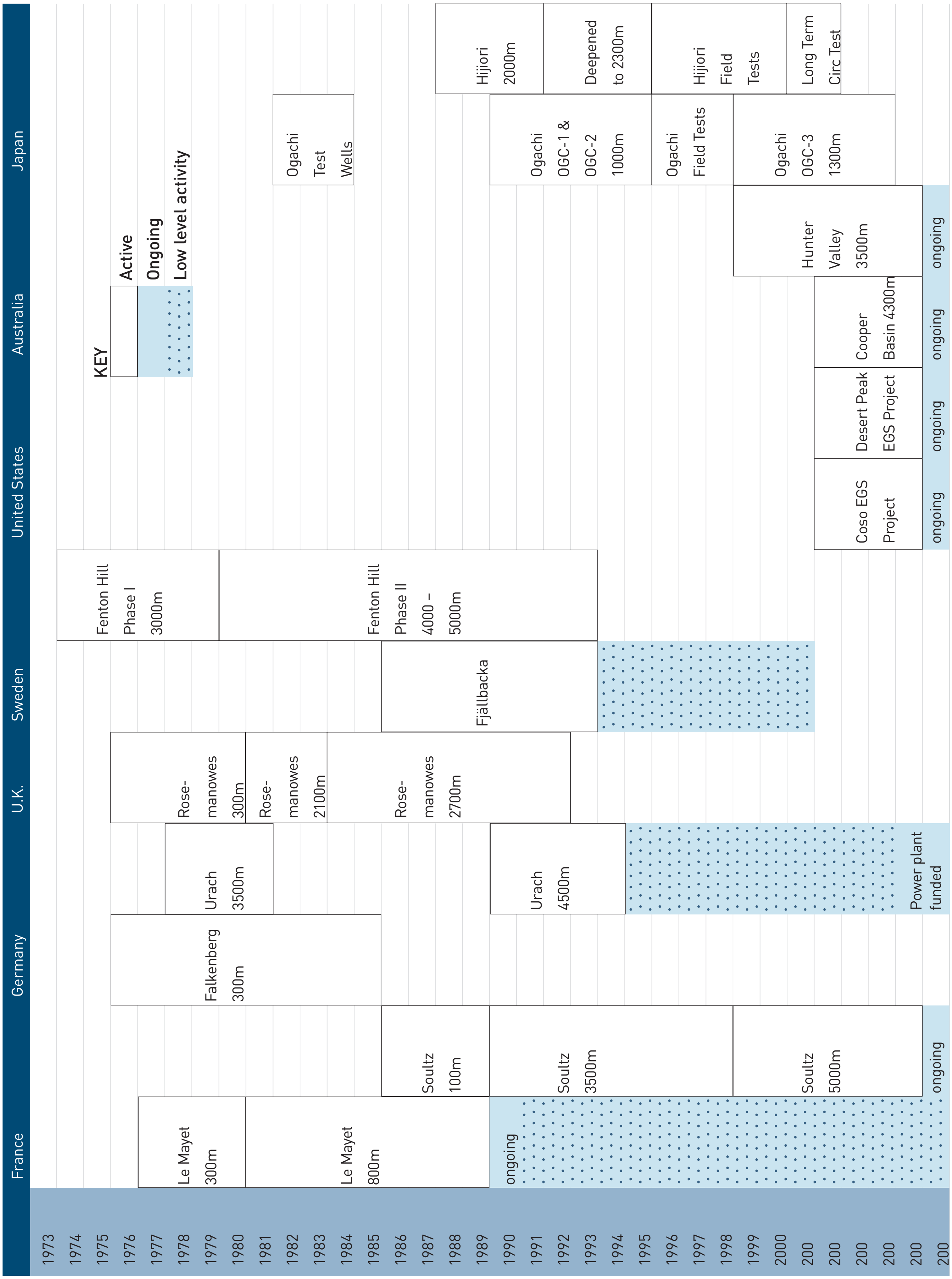

Figure 4.1 Schedule of major HDR and EGS projects worldwide.

While the Fenton Hill experience demonstrated the technical feasibility of the HDR concept by 1980, none of the testing carried out at Fenton Hill yielded all the performance characteristics required for a commercial-sized system. Three major issues remained at the end of the project as constraints to commercialization: (i) the demonstration of sufficient reservoir productivity with high-productivity fracture systems of sufficient size and thermal lifetime to maintain economic fluid production rates (50 to 100 kg/s per well pair at wellhead temperatures above 150°C), (ii) the maintenance of these flow rates with sufficiently low pumping pressures, and (iii) the relatively high cost of drilling deep (> 3 km) wells in hard rock. Drilling costs become the dominant economic component in low-grade, low-gradient EGS resources (see Chapter 6). In certain geologic situations, controlling water losses will be important, as it can have negative economic and environmental impacts.

Initially, the Los Alamos team and others tried to adapt techniques from oil well stimulation using hydraulic fracturing to produce idealized vertical "penny-shaped" fractures formed in a rock mass that behaves as an isotropic, homogeneous continuum where the minimum stress is in the horizontal direction. The implication of creating a reservoir in such a medium was that the most likely effect of water injection under high pressures would be to create a new fracture by tensile failure, thus forming the required surface area needed for heat mining (Smith et al., 1975; Kappelmeyer and Rummel, 1980; Duffield et al., 1981; Kappelmeyer and Jung, 1987).

After several years of active field work, some researchers recognized that EGS reservoirs probably consisted of 3-dimensional networks of hydraulically activated joints and fractures. These fissure systems contribute to the connection between injection and production boreholes, rather than just one – or even a series of – artificially created hydraulic fractures (see, for example, Batchelor, 1977; and Armstead and Tester, 1987).

By the early 1980s, research at various sites (Pine and Batchelor, 1984) confirmed that the creation of new hydraulic fractures was not the dominant process; but that the shearing of natural joints favorably aligned with the principal directions of the local stress field was a more important mechanism. These joints could be completely or partly sealed in their natural state. They fail in shear, because fluid injected under pressure reduces the normal stress across them, but only marginally affects the magnitude of the shear stress. The shearing mechanism allows frictional slippage to occur before tensile failure, i.e., there will be a component of shearing ahead of any hydraulically fractured zone (Baria et al., 1985; Baria and Green, 1989). Shearing of the fractures increases their aperture through self-propping on the naturally rough surfaces.

The realization that shearing on existing joints constitutes the main mechanism of reservoir growth has been one of the most significant outcomes of the international research projects. This has led to a basic change in how researchers interpret the evolution of the structure of an EGS reservoir, as a result of hydraulic pressurization. It has led to a departure from conventional oil field reservoir development techniques (which emphasize discrete hydraulic fracturing as a means of stimulation) toward a new technology related to the properties of any jointed rock mass that is subjected to a particular anisotropic stress regime. Because all formations that have been investigated so far have some sealed or partly sealed fractures (even those in continental shield areas with very low stresses), we can stimulate fracture networks and have them stay open using pumping pressures just over the critical pressure for shear failure. It should also be mentioned that, in every case, connections between the wells follow multiple paths. Every well has a number of flow entry and exit points. These occur at various depths, and their relative importance can change as a function of different pressure regimes.

The most important conclusion from all this prior work regarding the development of EGS as a power-producing technology is that we can probably form an EGS reservoir at any depth and anywhere in the world that has both a temperature high enough for energy conversion and sufficient far-field connectivity through existing natural fractures. Nonetheless, uncertainties still exist, for example, regarding the natural state of stress and rock properties, even within well-characterized geologic regions. Most important, the existence of anisotropic stresses in the rock as a prerequisite for stimulation by shear failure is fundamentally different than normal practice in oil- and gas-bearing formations. Other aspects of the reservoir structure may cause operational problems down-hole, such as mapping existing major faults and fractures that may act as flow barriers or conduits – and cause problems for our system.

Today, because of a limited understanding, we cannot predict the long-term effect of injecting water – which is not in chemical or thermal equilibrium with the rock – into the reservoir. Dissolution and precipitation will certainly occur at different points in the system, leading to both improvements and reductions in permeability. If a highly permeable fracture exists (or develops) in the system, it can result in a short circuit that may require aggressive remediation, such as drilling a sidetrack into a new area of rock. Sustained pressurization may also lead to unproductive volumetric reservoir growth and higher water losses.

Many features associated with the technical feasibility of EGS/HDR technology have been demonstrated at more than one site in the past 30 years. However, the major shortcoming of the field testing, so far, is that circulation rates through the stimulated regions have been below commercially viable rates. Recent progress at Soultz and Cooper Basin suggests that the ability to reach commercial levels is reasonably close, as will be discussed later in this chapter.

Taking all uncertainties collectively, we have not yet seen any “show stoppers” to making EGS work technically. While a given stimulation method may not provide for efficient, cost-effective heat mining at today’s energy prices, it still extracts net energy. Field efforts have repeatedly demonstrated that EGS wells can be drilled; pre-existing, sealed fractures at depth can be stimulated; and a connection can be made between wells. Fluid can be circulated through the network and heated to economic temperatures; and we can maintain the circulation, and use the heat from the produced fluid directly – or use it to generate electricity.

4.3 Fenton Hill

4.3.1 Project history

The project at Fenton Hill was the first attempt anywhere to make a deep, full-scale HDR reservoir. The site – on the edge of the Valles Caldera at the northern end of the Rio Grande rift zone in north-central New Mexico – was chosen for its heat and rock characteristics, as well as its proximity to the Los Alamos National Laboratory where the project was conceived. The purpose of the project was to develop methods to extract energy economically from HDR systems located in crystalline, granitic/metamorphic basement rock of suitably high temperature.

The R&D program was roughly divided into two major phases. Phase I, starting in 1974 and completed in 1980, dealt with field development and associated research on a 3 km deep reservoir with a temperature of about 200°C. Phase II followed in 1979, with the drilling of EE-2 into a deeper (4.4 km), hotter (300°C) reservoir. Figure 4.2 shows a map of the site and some characteristic properties of the formation and stimulated reservoirs.

The first deep well drilled at Fenton Hill, called GT-2, was started on February 17, 1974, and was completed to a temporary depth of 2,042 m in September 1974. Following the completion of the well, a series of hydraulic fracturing tests was run, and completed in early October of 1974. After these tests were completed, the well was deepened to 2,932 m. Bottom-hole temperatures (BHT) were about 180°C.

The second deep hole drilled at Fenton Hill was Energy Extraction Hole 1 (EE-1). EE-1 was drilled from May 1975 through October 1975, to a total depth of 3,064 m and with a similar BHT as GT-2. Additional hydraulic fracturing was then performed, but the reservoir connecting the wells was deemed inadequate.

It was determined that additional fracturing would likely not create the desired reservoir connection. As a result, it was decided to directionally redrill one of the wells into the fracture system created by the other. In 1977, an attempt to establish a high-permeability flow path between the two was performed on GT-2, at approximately 2,500 m (GT-2A), and was also determined to be inadequate. The lower part of GT-2A was then cemented in May 1977; and another hole, named GT-2B, was directionally drilled out of the upper portion of GT2-A at around 2,530 m. An acceptable connection was made between GT2-B and EE-1 at 2,673 m, with an average separation between the two boreholes of 100 m. Figure 4.3 shows the wells in vertical profile with the stimulated fracture zone shown in hatching (Tester and Albright, 1979).

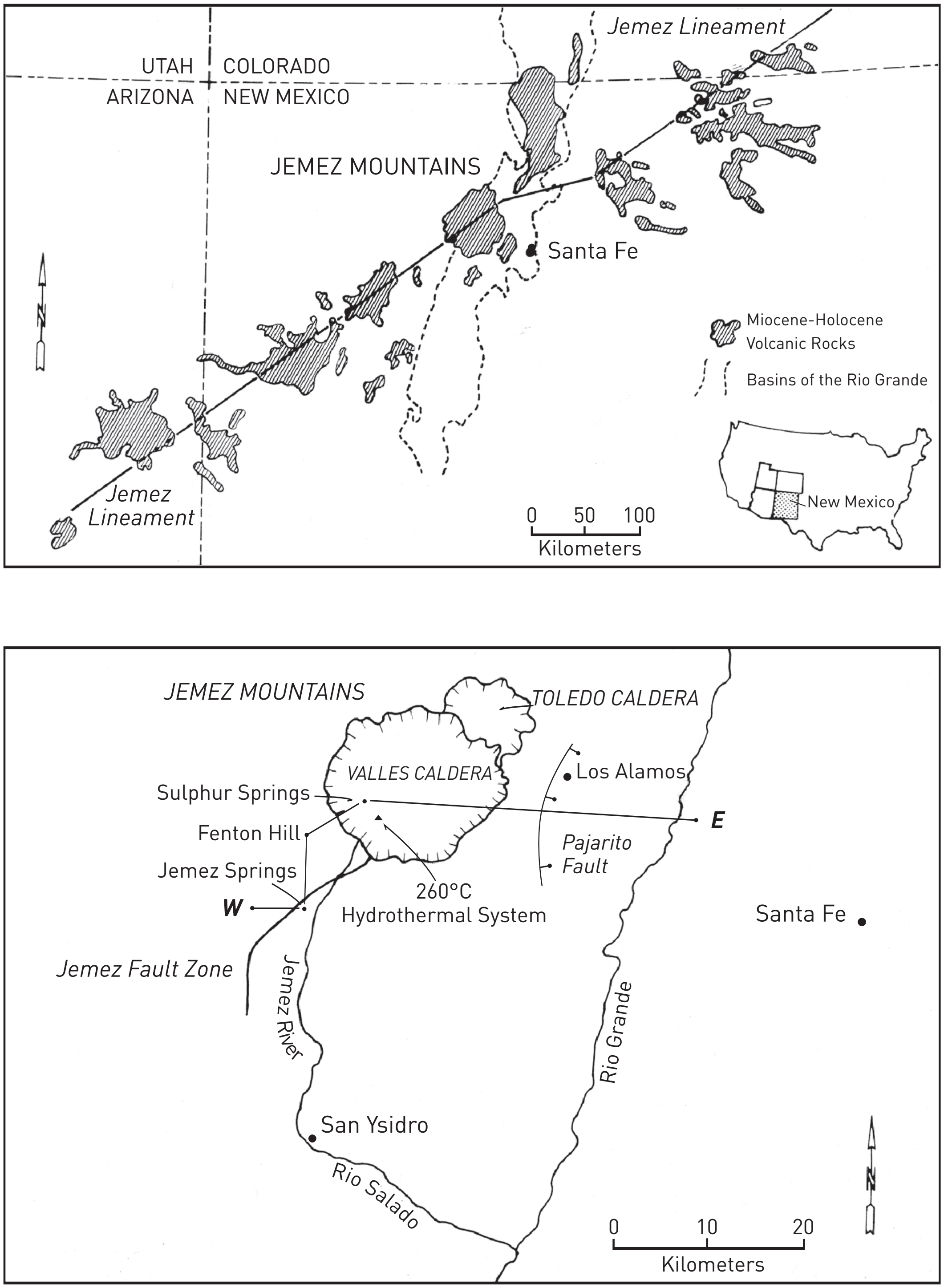

Figure 4.2 Map of Fenton Hill site and properties of formation and stimulated reservoirs.

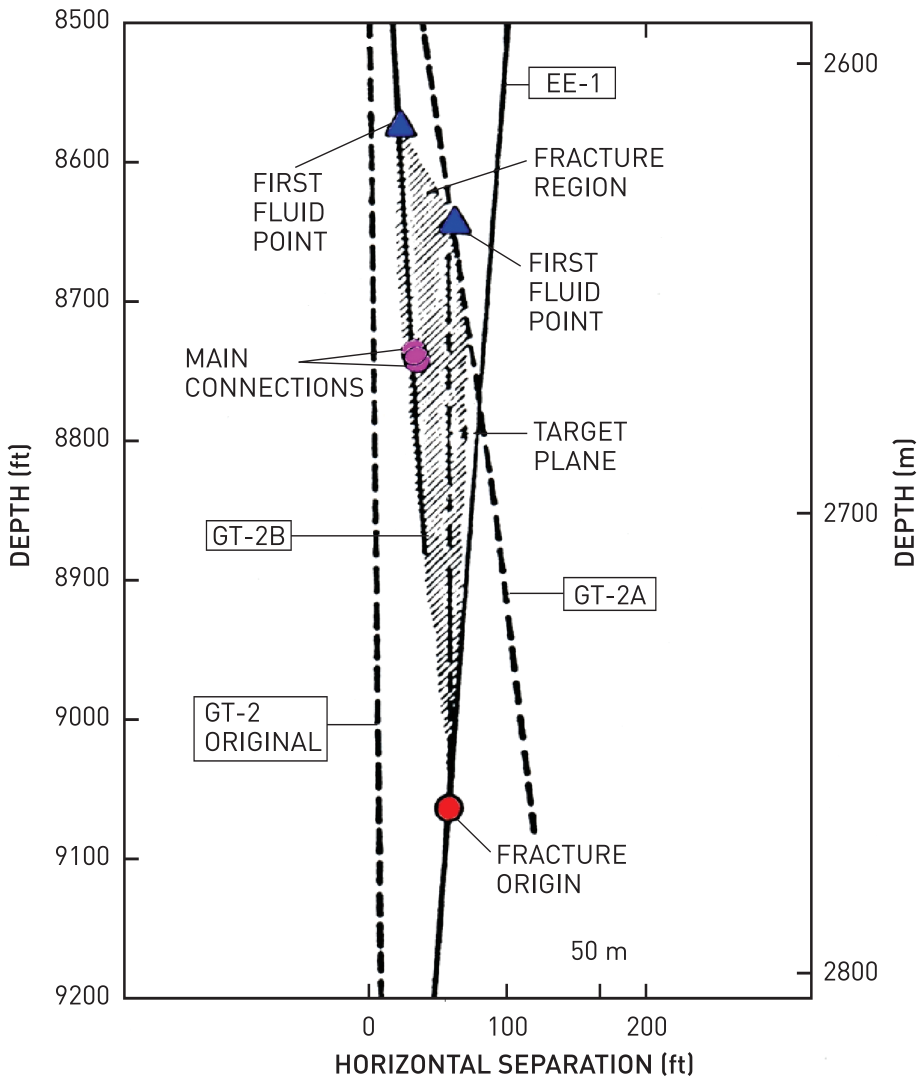

Figure 4.3 Elevation view of wells EE-1, GT-2, GT-2A, and GT-2B at the Fenton Hill site during Phase I testing.

Between June 1977 and December 1980, five circulation experiments were conducted in the Phase I system, lasting for 417 days. The water run through the system produced between 3 and 5 MWt, and powered a 60 kW binary fluid turbine generator.

In April 1979, drilling began on a new set of wells, EE-2 and EE-3, to be drilled deeper than the other wells. The wells were directionally drilled at about 35° to a vertical plane, and separated by 380 m vertically. The deeper of the two, EE-2 reached a depth of 4,390 m and BHT of 327°C. From 1982-1984, the wells were then hydraulically fractured at multiple depths. In all these (and subsequent) experiments, the progress of fracture growth was followed by microseismic event monitoring. The reservoir created by these experiments did not grow in the direction predicted, and an inadequate connection was established between the two wells. It was determined that this was caused by an unanticipated shift in the stress field in the deeper part of the formation – a major finding from this phase of the project.

It appeared unlikely that additional conventional hydraulic fracturing would stimulate the necessary fracture growth, and so the team again chose to directionally redrill one of the existing wells. In September 1985, the upper well, EE-3, was sidetracked at 2,830 m and drilled to a depth of 4,018 m with BHT of 265°C, and renamed EE-3A (see Figure 4.4A). The newly drilled well intersected several of the fractures created by the hydraulic stimulation, and the connection created was acceptable for large-scale testing.

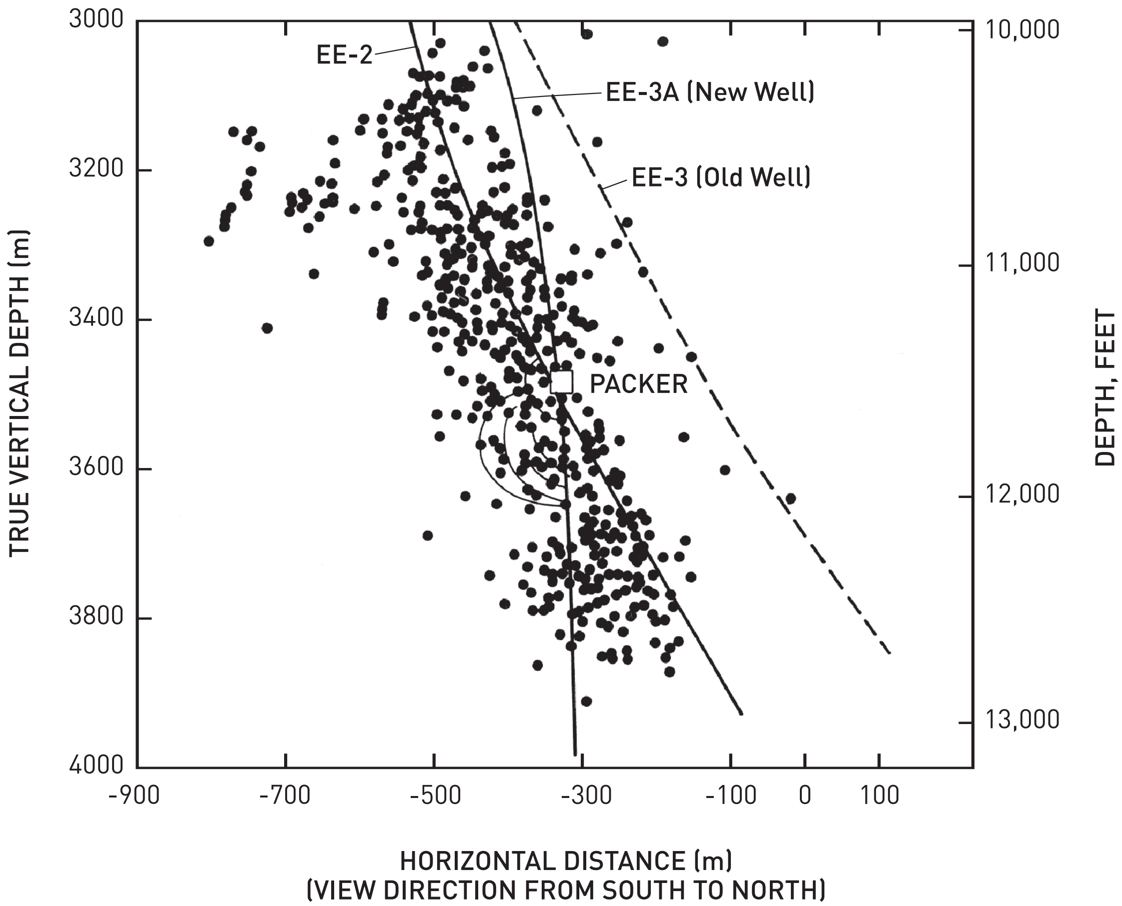

Figure 4.4A Elevation view of wells at Fenton Hill site. The data points represent microseismic events observed during stimulation.

The initial closed-loop flow test of the Phase II system began in May 1986 and ran for 30 days. During the test, 37,000 m^3 of water was pumped through the system, with 66% of that being recovered; another 20% was recovered during venting after the test. Flow rates were between 10.6 and 18.5 kg/s, with between 26.9 and 30.3 MPa (pascals) of pressure on the injection wellhead. The fluid extracted from the reservoir reached 192°C, with the temperature still increasing at the end of the test. Results of the flow test were encouraging and further testing was planned.

During venting in the first flow test on the system, the casing and liner in well EE-2 at 3,200 m suffered a partial collapse. It was decided that the best way to fix the leakage caused by the collapse was to seal off the well just above the collapse, and redrill the well from that point. The redrilling took only 30 days to drill 800 m, progressing at a rate 2.5 times faster than the rate drilled in 1978 and 1979. The redrilled wellbore was renamed EE-2A to distinguish it from the earlier well.

Following recompletion of EE-2A, flow testing was conducted in 1989-1990 to obtain data for planning the long-term flow test. Tests conducted at equilibrium pressures did not have the high loss of fluid that had been experienced at pressures above the fracture breakdown pressure, which had been found to be less than 19 MPa. Also at pressures below the critical pressure, the reservoir did not continue to grow. While temperature in the produced fluids changed over time, the downhole temperature did not change measurably during the testing. Other testing maintained pressurization of the reservoir by cyclically injecting fluid while sustaining wellhead pressure on the production well (Duchane, 1993).

The facility for the long-term flow test was constructed, starting in 1990, while shorter flow tests continued. Several pieces of equipment were installed for this phase of testing, including a heat exchanger to dump waste heat from the produced fluid, larger makeup water storage ponds, and larger capacity makeup water pumps and injection pumps. The first stage of the long-term flow test of the Phase II system started on April 8, 1992. The test continued for 112 days, until failure of the injection pumps necessitated shutdown on July 31. Cold water was injected at 12.5-15 kg/s (90-110 gpm) and produced at temperatures of more than 180°C (Duchane, 1993). During the first stage of testing, the pumps were of the reciprocating type driven by diesel engines; but, for the second stage of testing, the pumps were centrifugal and driven by electric motors. This test lasted 55 days with constant downhole temperatures. However, surface temperatures dropped, possibly because low flow rates resulted in heat loss to a shallow, cooler subsurface region.

During the latter phases of work at Fenton Hill, support for the work had declined to the point where it was not possible to maintain sufficient technical staff to perform continuous flow testing of the reservoir – nor was it possible to perform the necessary redrilling and wellbore repairs to upgrade the downhole connections to the large fractured system that had been created (see Figures 4.4A and 4.4B). With prospects for continued funding very low, all field experiments were terminated at the Fenton Hill site by 2000, after which the site was decommissioned.

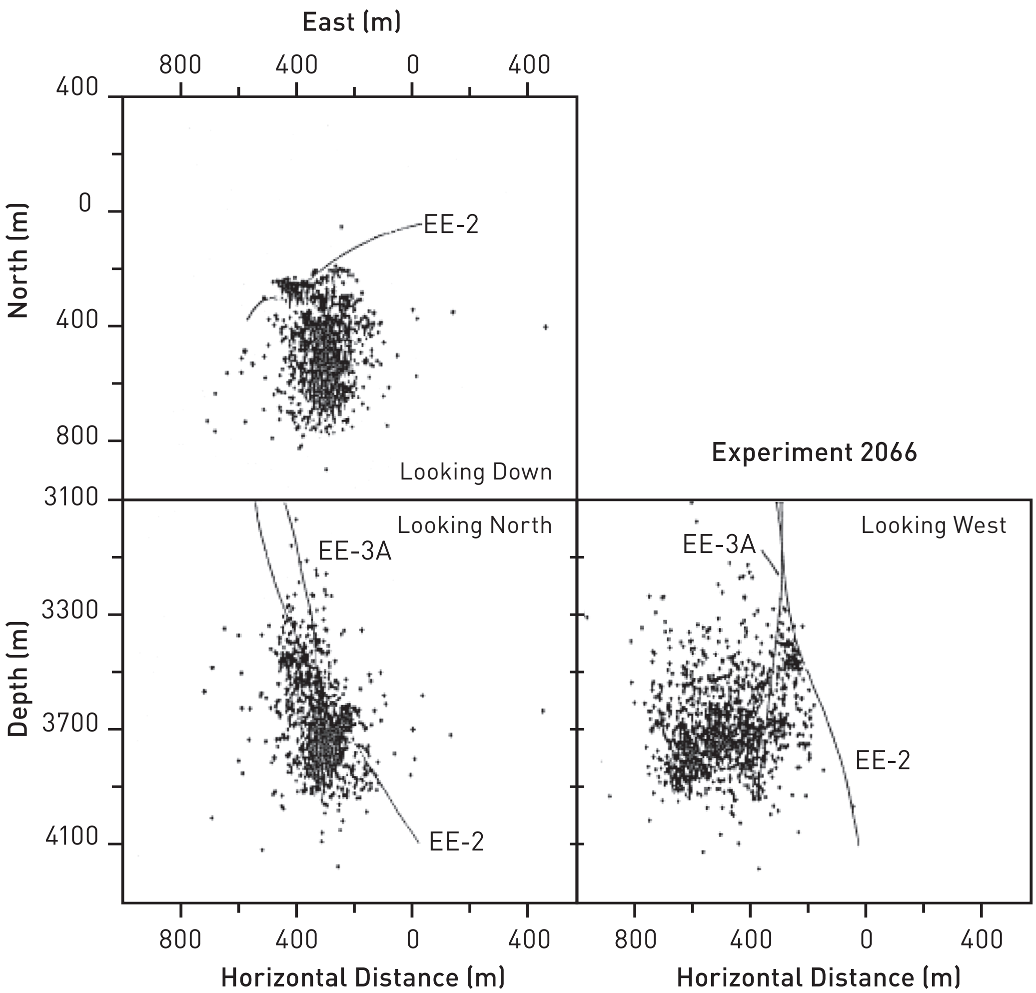

Figure 4.4B Fenton Hill microseismic event locations during stimulation of EE-3A, on January 30, 1986 (Los Alamos National Laboratory).

4.3.2 Lessons learned at Fenton Hill

- Deep (15,000 ft, ≈5 km), high-temperature wells can be completed in hard, abrasive rock.
- Low-permeability (microdarcy or lower) crystalline rock can be stimulated to create hydraulically conductive fractures.
- Conventional drilling methods can be adapted for the harsh environments encountered in reaching zones of rock at about 200°C to 300°C, which are hot enough to be suitable for commercial power production.
- Hydraulic-pressurization methods can create permanently open networks of fractures in large enough volumes of rock (>1 km^3) to sustain energy extraction over a long time period.
- The EGS reservoir can be circulated for extended time periods and used to generate electricity.
- Creating the connection between wells was a crucial step in developing the EGS reservoir.
- Connection was easier to establish by drilling into the fractured volume, once it was stimulated and mapped.
- Directional drilling control was possible in hard crystalline rock, and the fractures mapped by microseismic monitoring could be intersected using directional drilling.
- The Phase I reservoir, although too small by design for commercial operation, provided a test-bed for creating the larger volumes needed to achieve commercial rates of production.

- Techniques were developed to reduce pressure drop in and near the wellbore, often referred to as wellbore impedance.
- Models of flow and heat transfer were developed that, along with data collected during testing, can be used to predict the behavior of the EGS reservoir.
- The thermal-hydraulic performance of the recirculating Phase I system was successfully modeled, and indicated approximately 10,000 m^2 of effective surface area when matched to field data. This area is too small by about a factor of 100 for a commercial-scale system.
- Techniques using chemical tracers, active and passive acoustic emissions methods, and other geophysical logging techniques can be used to map the created fractures.
- At the deeper depths required to reach higher rock temperatures (> 300°C), wells could still be drilled, fractures created through hydraulic stimulation, and the fractured volume mapped.
- Although it took some effort, the fractured volume could be intersected by drilling into the mapped fractures.
- Connections between the wells could be established and fluids circulated at commercial temperatures for extended time periods.
- The high pressures needed to keep the Phase II fractures open caused operational problems and required substantial amounts of power.
- Although the reservoir had the potential of producing 1 million m^2 of heat-transfer surface, based on the fluid volume pumped, the fracture pattern that was observed did not match that predicted by early modeling.
- The reservoir could be circulated in such a manner that the fractured volume did not continue to grow and, thus, water losses were minimized.
- If injection pressures were lowered to reduce water loss and reservoir growth, the flow rates were lower than desired, due to higher pressure drop through the reservoir. If water was injected at high enough pressures to maintain high flow rates, the reservoir grew and water losses were high. This meant that the fractures were being jacked open under high-injection pressures, causing extension of the fractures and increased permeability. At lower pressures, this did not happen, so the pressure drop was higher and flow rates much lower.
- High-temperature tools and equipment for downhole use had to be developed and adapted to evaluate the stress regime; determine the orientation of pre-existing fractures; monitor downhole pressure, temperature, and flow rates; and to provide geophysical data on the reservoir. Much of this equipment was developed by the national laboratory as needed and was not intended for commercial use.

4.4 Rosemanowes

4.4.1 Project history

As a result of experience during Phase I at Fenton Hill, in 1977, the Camborne School of Mines undertook an experimental hot dry rock (HDR) project at Rosemanowes Quarry (near Penryn in Cornwall, U.K.) in the Carnmenellis granite (see Figure 4.5). The project was funded by the U.K. Department of Energy and by the Commission of the European Communities, and was intended as a large-scale rock mechanics experiment addressing some of the issues surrounding the stimulation of adequate fracture networks (Batchelor, 1982). Because the temperature was restricted deliberately to below 100°C, to minimize instrumentation problems, this project was never intended as an energy producer. The site was chosen because mine works in the area allowed rock characterization to a depth of more than 1,000 m, due to the clearly defined vertical jointing evident in the exposed granite – and because of the area's heat flow and high-temperature gradients between 30 and 40°C per kilometer. The main tectonic regime of the area is strike-slip.

Figure 4.5 European EGS site locations (Google Earth).

The Carnmenellis granite is roughly ellipsoidal in outline, and it forms part of a continuous granite batholith of early Permian age of more than 200 km in length. The base of the granite extends well below a depth of 9 km. At the Rosemanowes site, the granite is porphyritic near the surface, tending to become equigranular at about 2 km. Phase 1 of the project started in 1977, with the drilling of a number of 300 m test wells. The purpose of these wells was to test some possible fracture-initiation techniques. It was found, however, that the stress field at this depth was unrepresentative of that to be encountered at depths of real interest.

For Phase 2A of the project, two wells were planned with a total vertical depth (TVD) of about 2,000 m, where the temperature was expected to be around 80-90°C – both were deviated in the same plane to an angle of 30 degrees from the vertical in the lower sections, and separated by 300 m vertically. In 1980, the drilling of RH11 (production) and RH12 (injection) began, and took only 116 days. Bottom-hole temperatures recorded at RH12 reached 79°C.

Stimulation of RH12 (the lower well) then followed, initially with explosives, and then hydraulically at rates up to 100 kg/s and wellhead pressures of 14 MPa. Due to the mainly vertical nature of jointing in the granite, conventional wisdom was that hydraulic fracturing (tensile fracturing; penny-shaped crack) would cause the reservoir to grow vertically upward, especially around 2,000 m, where the minimum principal stress was horizontal. However, microseismic monitoring showed that the majority of fracturing and the reservoir grew by shearing mode and not tensile fracturing; and reservoir growth occurred primarily in a vertically downward direction, opposite the predicted direction (Batchelor et al., 1983; Pine and Batchelor 1984; Baria et al., 1989). The predominant downward growth of the reservoir continued through the subsequent nine months of circulation, and testing of the completed system showed it was not suitable for the purpose of modeling a full-scale commercial HDR reservoir.

Phase 2B began in 1983 and entailed the drilling of a third well, RH15 (see Figure 4.6), which would be drilled below the existing wells, to access the large reservoir already created in Phase 2A. The well was drilled to a TVD of 2,600 m and bottom-hole temperatures around 100°C were recorded. Hydraulic stimulation of the well was carried out similar to RH12, and circulation began in 1985 (see Figure 4.7), with RH12 continuing to be the injection well and RH15 the primary producer. A series of flow tests was then carried out through September 1986, with rates gradually stepping up. The reservoir was then circulated continuously at various flow rates (typically around 20-25 kg/s) for the next four years.

Temperature drawdown over the period of the long-term flow test caused a downhole temperature drop from 80.5°C to 70.5°C. Injection rates through the testing phase varied from 5 to 24 kg/s. In the 5 kg/s case, the return from the production well was 4 kg/s and the wellhead pressure was 40 bar. In the 24 kg/s case, the return from the production well was 15 kg/s and the wellhead pressure 10.5 MPa. Flow-path analysis based on spinner, temperature, and other well log data showed that a preferential pathway – or short circuit – developed, which allowed cool injected water to return too rapidly to the production well (Batchelor, 1986).

The experimental work at Rosemanowes Quarry was continued in Phase 3A (which involved no further drilling) with further circulation and other tests. In the downhole pump test in Phase 2C, lowering the pressure in the production well seemed to close the joint apertures close to the borehole and increase the impedance. An experiment in Phase 3A to place a proppant material in the joints near the production borehole was designed to demonstrate that this might solve the problem in a deep system. The sand used as proppant was carried into the joints as part of a secondary stimulation using a high viscosity (700 centipoise) gel. This stimulation significantly reduced the water losses and impedance, but it also worsened the short circuiting and lowered the flow temperature in the production borehole even further. It was concluded that the proppant technique would need to be used with caution in any attempt to manipulate HDR systems.

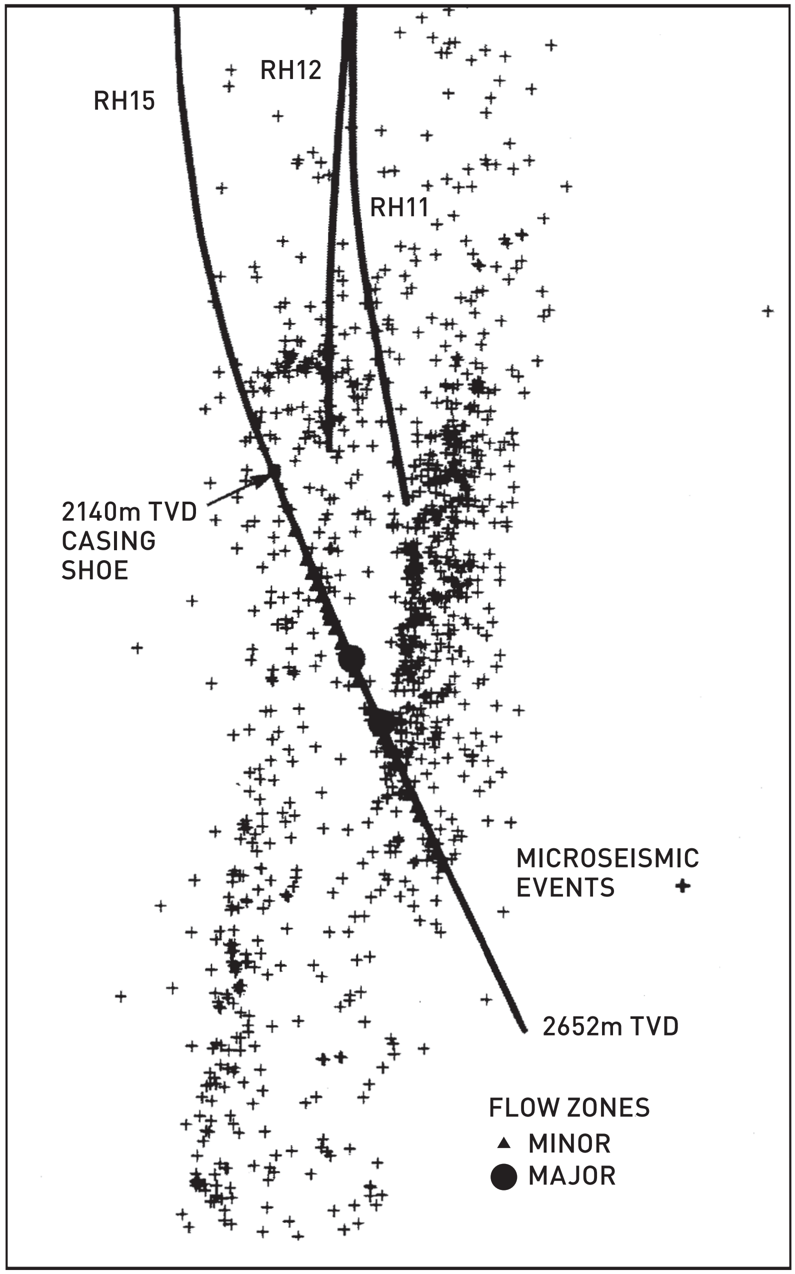

Figure 4.6 Flow zones and microseismicity in RH15.

Figure 4.7 Major stimulation of Well RH15 at Rosemanowes in July 1985, 5,500m^3 at up to 265 L/s (100 bbl/min), surface pressure of 16 MPa (2,320 psi).

An experiment was also carried out in Phase 3A to shut off the section of the production borehole that had been shown to contain the outlet from the short circuit. A temporary packer assembly was installed close to the bottom of the borehole to seal off all the upper parts of the wellbore, and a production flow test was carried out to measure the flow rate from the low-flow zone at the bottom of the borehole under these conditions. The short circuit was sealed off, but a very low flow rate was obtained; and a further stimulation carried out from the bottom of the borehole gave no significant increase in flow. A subsequent interpretation of these results suggested that the most recently stimulated zone was parallel to, but largely unconnected with, the previously stimulated zone (Parker, 1989). This is a key observation in that it shows individual fractures at the well can have independent connections to the far-field fracture system, i.e., the natural fracture network is not well-connected enough to form a commercial-size reservoir over short sections of a well.

4.4.2 Lessons learned at Rosemanowes

- The fractures created by hydraulic stimulation, which best connect across the reservoir, are not formed through tension, as in the hydraulic fracturing used in oil and gas wells. Instead, they are created by shearing on pre-existing joint sets.
- Stress fields in crystalline rock are invariably anisotropic, so the natural fractures fail in shear, long before jacking takes place. Having sheared, the natural fractures then self-prop and stay open.
- It is possible to stimulate natural fractures and improve permeability – and create a connected volume of hot rock.
- Too high an applied pressure results in runaway fracture growth, leading to water loss and/or short circuits.

- There are always critically oriented natural fractures, so while it is easy to stimulate with lower pressures, it is also very easy to apply too high a pressure.
- The downward growth at Rosemanowes (Figure 5.1 in Chapter 5), and that observed at Fenton Hill, are the result of the combination of *in situ* stress and stress gradient changes caused by imposed temperature and pressure changes in the rock.
- In the general case, a prediction of the direction of fracture growth is difficult in the absence of precise downhole data. Even with near-wellbore data from image logs, the fractures may not grow exactly as predicted. As a result, it is better to create the reservoir first, and then drill into it (Batchelor, 1987).
- Pressure drop through the system ("impedance") was a major problem. This was caused both by the low permeability of the reservoir and by frictional losses in the wellbores and in the near-wellbore area. Pressure drop is a critical parameter for two reasons: (i) the higher the pressure drop, the greater the pumping power required – and, hence, the greater the parasitic losses (an economic issue); and (ii), more important, a high impedance requires high downhole pressures to achieve the required flow rate, and these could easily exceed the levels at which runaway fracture growth and consequent water losses are incurred.
- One way to increase reservoir permeability is to choose areas where there are low permeability, pre-existing fractures closely spaced in the wellbore and that are oriented so that they will be likely to fail during stimulation (Batchelor, 1989).
- Near-wellbore permeability reduction ("skin effect") can increase pressure drop and decrease flow rates. Placing proppants in this near-wellbore area in the injector may require high pressures and flow rates that increase the likelihood of short circuits.
- Probably the most important single lesson from this experiment is that hydro-fracturing and artificial fractures are almost irrelevant. The natural fracture system dominates everything (Batchelor, 1989).
- Natural fractures are pervasive in crystalline rocks at all depths and all locations we have investigated. Even if one does generate an artificial fracture, deliberately by hydro-fracturing – or, more often, accidentally while drilling – it will intersect the natural system within meters, and from there on the behavior is dominated by the natural system.
- Overstimulating pre-existing fractures can result in a more direct connection from injector to producer than is desired, so that cool fluid can "short-circuit" through the reservoir resulting in a lower production temperature.
- At Rosemanowes, it became clear that everything one does to pressurize a reservoir is irreversible and not necessarily useful for heat mining. For example, pumping too long at too high a pressure will cause irreversible rock movements that could drive short circuits as well as pathways for water losses to the far field.

4.5 Hijiori

4.5.1 Project history

From 1981 to 1986, the New Energy and Industrial Technology Development Organization (NEDO) participated in a joint research effort into the development of geothermal energy through stimulation of low permeability rock at Fenton Hill, New Mexico. This was carried out with the United States and West Germany under an implementation agreement of the International Energy Agency (IEA). Based on this research, NEDO conducted studies in Hijiori to determine whether the technology developed at Fenton Hill could be adapted to the geological conditions found in Japan. The Hijiori site is in Yamagata Prefecture, on the Japanese island of Honshu (Figure 4.8). The project was sited on the southern edge of Hijiori caldera, a small caldera on the side of the large Pleistocene Gassan volcano, which last erupted about 10,000 years ago.

The location was chosen to take advantage of the high temperature gradient in this area of recent volcanic activity. The area had been extensively mapped and some temperature gradient drilling had been carried out (Figure 4.9). Although the regional tectonics are compressional along the axis of the island of Honshu, the stress regime near the edge of the caldera is very complex. Major faults along with ring fractures associated with the caldera collapse cause stress changes both horizontally and vertically over short distances. 4-19

The shallow reservoir was drilled starting in 1989. One injector (SKG-2) and three producers (HDR-1, HDR-2, and HDR-3) were drilled between 1989 and 1991. The depth of all but HDR-1 was about 1,800 m – HDR-1 was completed at a depth of 2,151 m. Natural fractures were intersected in all the wells at depths between 1,550 and 1,800 m depth; see Figure 4.10 (Swenson et al., 1999). The temperature reached more than 225°C at 1,500 m. The maximum temperature in the 1,800 m deep fractures was close to 250°C. The spacing between the wells was kept to fairly small distances: the distance from SKG-2 to HDR-1 is about 40 m, to HDR-2 about 50 m, and to HDR-3 about 55 m at the 1,800 m depth (Tenma et al., 2001)

The deep reservoir – below 2,150 m – was accessed by deepening HDR-2 (renamed HDR-2a after deepening) and HDR-3, between 1991 and 1995, to about 2,200 m. HDR-1 was used as an injector for the deep reservoir. Natural fractures were intersected in all wells at about 2,200 m. The distance from HDR-1 to HDR-2a was about 80 m, and to HDR-3 about 130 m at 2,200 m.

Hydraulic fracturing experiments began in 1988 with 2,000 m^3 of water injected into SKG-2. The stimulation was carried out in four stages at rates of 1, 2, 4 and 6 m^3/min. A 30-day circulation test was conducted in 1989 following stimulation. A combination of produced water and surface water was injected into SKG-2 at 1-2 m^3/min (17-34 kg/s), and steam and hot water were produced from HDR-2 and HDR-3. During the test, a total of 44,500 m^3 of water was injected while 13,000 m^3 of water was produced. The test showed a good hydraulic connection between the injector and the two producers, but more than 70% of the injected water was lost to the reservoir. However, the test was short and the reservoir continued to grow during the entire circulation period.

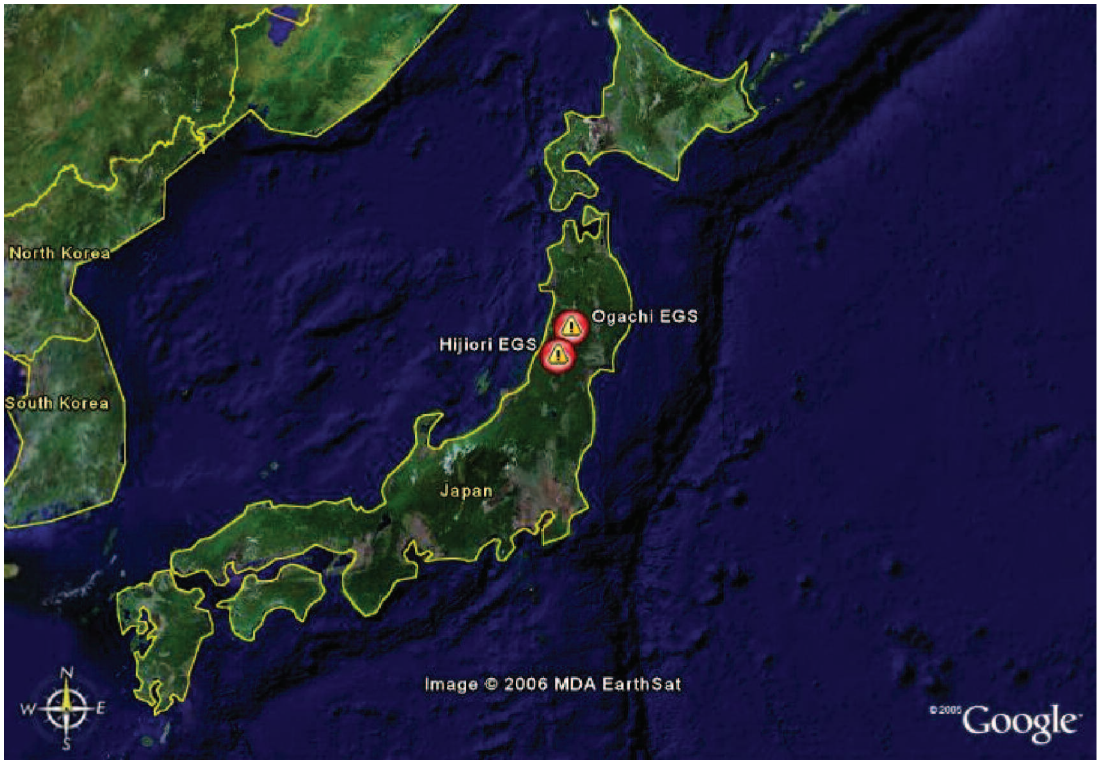

Figure 4.8 Map of EGS site locations in Japan (Google Earth).

Figure 4.9 Aerial view of Hijiori caldera.

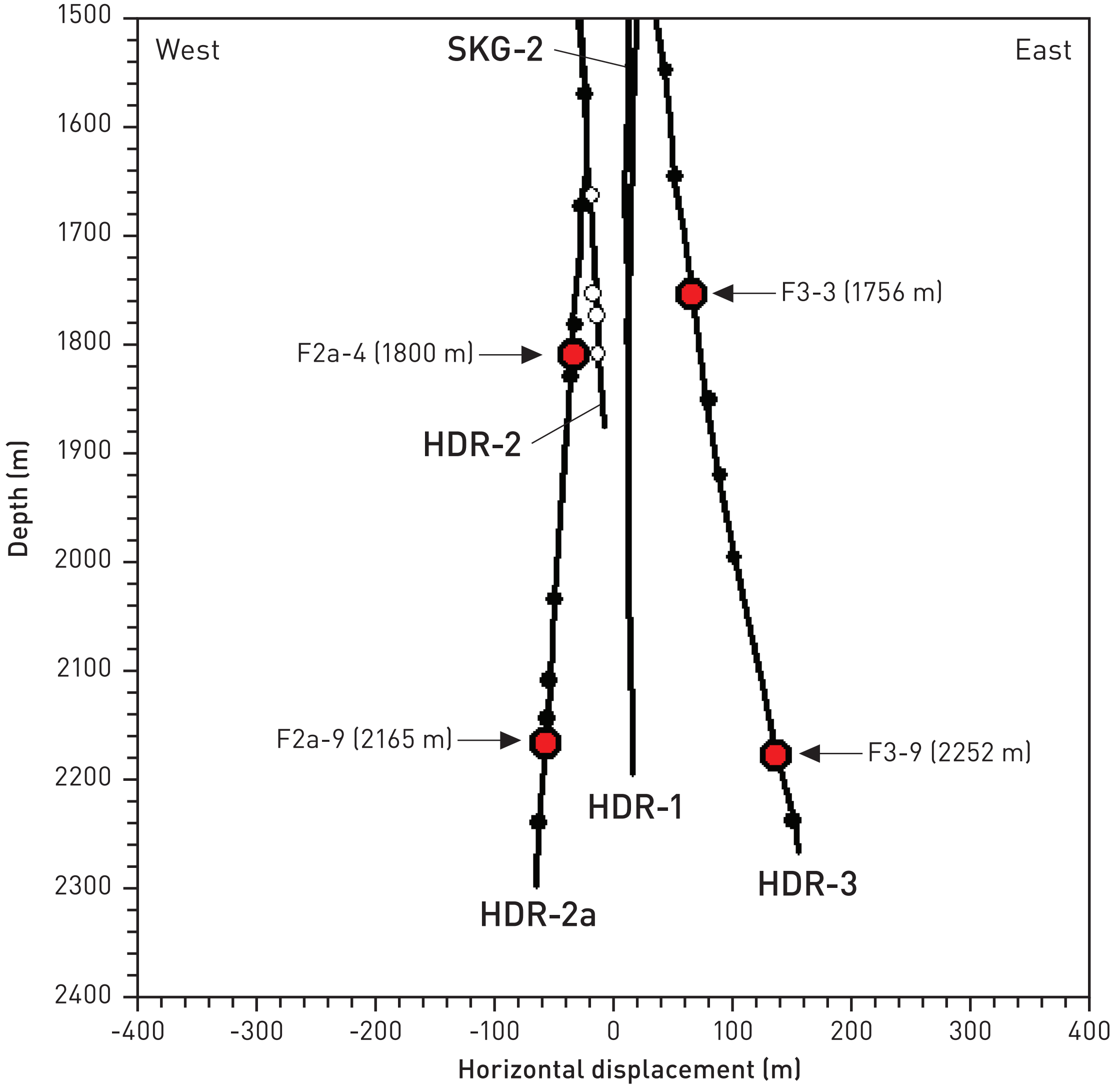

Figure 4.10 Hijiori wells. Red circles show intersections with major fractures.

After HDR-1 was deepened to 2,205 m in 1991, the well was hydraulically fractured in 1992 to stimulate the deep fractures. Then, 2,115 m^3 were injected in three stages at rates of 1, 2, and 4 m^3/min. Following stimulation, HDR-2a and HDR-3 were deepened to 2,302 m, and a 25-day circulation test was conducted in 1995. Injection was into HDR-1 at 1-2 m^3/min, while steam and hot water were produced from HDR-2 and HDR-3. A total of 51,500 m^3 of water was injected, while 26,000 m^3 of water was produced, i.e., about 50% recovery.

The stress state at Hijiori prior to stimulation was found using data from compression tests of core, differential strain curve analysis, and analysis of acoustic emissions data. The maximum and intermediate principal stresses were found at a 45° angle and trending northeast/southwest, while the minimum principal stress was approximately horizontal and north-south. Fracture apertures were measured from core in HDR-3 and are shown in Table 4.1. A borehole televiewer was used to identify fracture dip and direction from HDR-2a and HDR-3.

Table 4.1 Determination of reservoir volume at Hijiori and Ogachi using different methods (Kruger, 2000).

		Estimated Volume, 10^6 m^3			
		Hijiori		Ogachi	
Method	Condition	Upper Reservoir	Lower Reservoir	Upper Reservoir	Lower Reservoir
Swept geometric flow volume	Low Est.	6.3		0.75	
	High Est.	20		8	
Microseismic events volume	Events >1.5			0.012	0.65-1
	1σ envelop		1	3.7	10
Tracer testing	Modal Vol./ Porosity			0.2	3-5
Pressure testing	Bulk modulus, K			0.2	2
Prior heat-extraction modeling	For whole reservoir	0.7 - 6.3		0.14 - 1.8	

During 1996, further stimulation and short-term testing was conducted to prepare for a long-term test. In an attempt to better connect the HDR-3 to the injection well HDR-1 in the deep reservoir and reduce the amount of fluid loss, HDR-1 was used as injector while HDR-3 was produced and back pressure was held on HDR-2a. While there was no marked improvement in the connectivity, this experiment held out the hope that modifying the pressure in the reservoir could have an effect on the results of stimulation. This is an area where more work is needed (Hori et al., 1999).

Following additional circulation tests in 1996, a long-term test of the deep and shallow reservoirs was initiated in 2000 with testing continuing into 2002 (Schroeder et al., 1998; Tenma et al. 2000, 2001). A one-year circulation test of the deep reservoir was conducted with injection of 36°C water into HDR-1 at 15-20 kg/s. For the second phase of testing, injection into SKG-2 allowed testing of both the deep and shallow reservoir. Production of steam and water was from HDR-2a at 5 kg/s at about 163°C, and from HDR-3 at 4 kg/sec at 172°C. Total thermal power production was about 8 MWt. At the end of the test, the flow was used to run a 130 kW binary power plant. Test analysis showed that production was from both the deep and shallow reservoir (Matsunaga et al., 2000). During the test, scale problems in boreholes necessitated clean-out of the production wells. One interesting result of the test is that, while the injection flow rate remained constant at about 16 kg/s, the pressure required to inject that flow decreased during the course of the test from 84 to 70 bar. Total production from HDR-2a and HDR-3 was 8.7 kg/s with a loss rate of 45% (Okabe et al., 2000).

Well HDR-2a cooled dramatically from an initial temperature of 163°C to about 100°C during the long-term flow test. The test was finally halted, due to the drop in temperature. The measured change in temperature was larger than that predicted from numerical modeling (Yamaguchi et al., 2000).

4.5.2 Lessons learned at Hijiori

The Hijiori project provided useful data for future projects to build on. Added to the Fenton Hill and Rosemanowes experience, it became clear that it is better to drill one well, stimulate, map the acoustic emissions during stimulation, and then drill into the acoustic emissions cloud, than to try to drill two or more wells and attempt to connect them with stimulated fractures (Okabe et al., 2000).

- The reservoir continued to grow during the circulation test.
- If natural fractures already connect the wellbores, stimulation may result in an improved connection that causes short circuiting, particularly if the wellbore separation distances are small.
- The acoustic emissions (AE) locations from the deep circulation test suggest that the stimulated fractures or the stress field change direction away from the well.
- The lineation found from the AE locations in the shallow reservoir parallel the direction of the lineation found during the stimulation, but the acoustic emissions farther from the well during the circulation test trend in a new direction.
- If the stress direction changes from one part of the reservoir to another, it may be almost impossible to predict how the stimulated fractures will be oriented and where they will grow and be most permeable.
- With current technology, it is difficult – if not impossible – to predict what the stress field will be in the wellbore prior to drilling; and it is even more difficult to know the stress field away from the borehole.
- It is much easier to drill into the zone that is mapped as the fracture zone from AE locations and establish a connection than to attempt to connect two existing wells.
- While attempts to control the stress field by modifying pressure in wells not being directly stimulated did not accomplish what was hoped for at Hijiori, this concept still holds promise. Further work is needed.
- At Hijiori, it was clear that while stimulation by injecting at high pressures for short periods had some effect on the permeability of the naturally fractured reservoir, injecting at low pressures for long time periods had an even more beneficial effect.
- The reservoir grew and connectivity improved more during circulation tests than during efforts to stimulate at high pressures.
- The data suggest that cool water short-circuited the modeled path length, either because fracture growth during injection testing connected the deep reservoir with the shallow one, or because the deep and shallow reservoirs were connected through one of the wellbores penetrating both zones.
- Well spacing needs to be as large as possible while still making a connection.

The Hijiori project also showed the value of understanding not only the stress field but also the natural fracture system. Both the Fenton Hill project and the Hijiori project were on the edges of a volcanic caldera. While very high temperature gradients can provide access to a large reservoir of thermal energy and can make the project economics better since one only needs to drill relatively shallow wells to reach very high temperatures, the geology, stress conditions, and fracture history of rocks in such areas can be extremely complex. This can make project design, construction, and management very challenging.

4.6 Ogachi

4.6.1 Project history

The Ogachi project is in Akita Prefecture, near Kurikoma National Park on Honshu Island, Japan (see Figures 4.8 and 4.11). The first exploration wells were drilled between 1982 and 1984 on the edge of the Akinomiya geothermal area, using the Mt. Yamabushi volcano as the heat source. The site was considered as an EGS project because, while temperatures were high – more than 230°C at 1,000 m (see Figure 4.11) – the productivity of the wells was low (Hori, 1999).

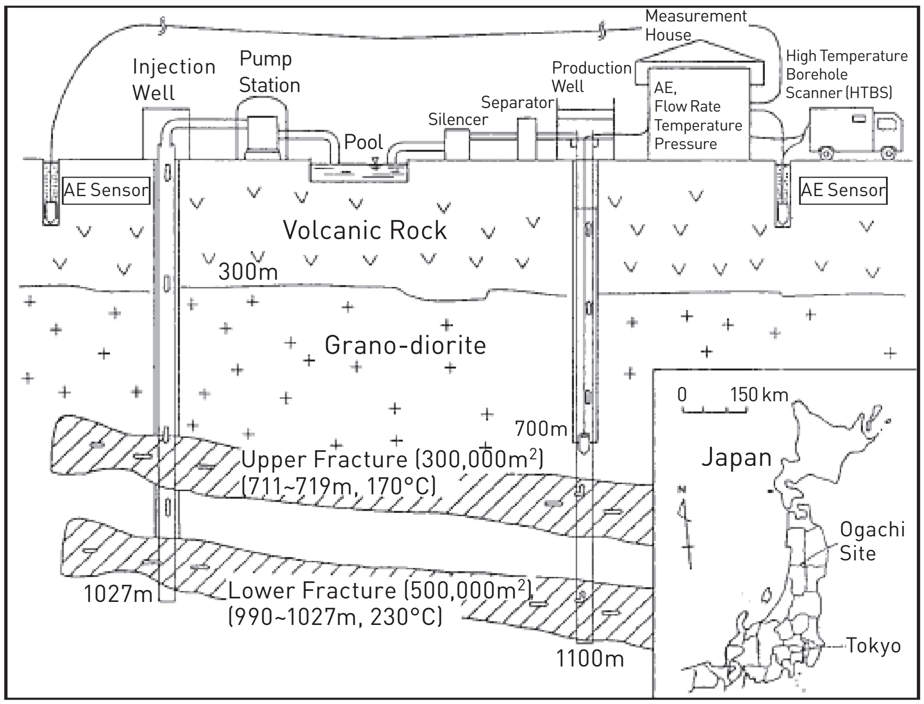

Figure 4.11 Illustration of the Ogachi HDR experiment (Kitano et al., 2000).

The well later used as an injection well, OGC-1, was drilled in 1990 to a depth of about 1,000 m and a temperature of 230°C. Two fracture stimulations were done in the 10 meters of open hole in the bottom of the well. Then a window was milled in the casing at a depth of 710 m, and a second fracture (termed the upper reservoir) was created from approximately 710-719 m.

Production well OGC-2 was drilled in 1992 to a depth of 1,100 m, where a temperature of 240°C was reached. The well is less than 100 m from OGC-1. A circulation test in 1993 with injection into OGC-1 and production from OGC-2 showed only 3% of injected water was produced. To improve the connection between the wells, OGC-2 was stimulated in 1994. A five-month circulation test following this stimulation showed that only 10% of the injected water was produced back (Kiho, 2000). The production and injection wells were again stimulated in 1995. A one-month circulation test showed an improved recovery of more than 25% of the total injection.

The permeability found ranged from $10^{-6} – 10^{-7}$ cm/s (approximately $10^{-3} – 10^{-4}$ Darcys) before fracturing. Permeability after fracturing improved by at least an order of magnitude to $10^{-4} – 10^{-5}$ cm/s. It was found that 15% of the total produced fluid could be attributed to the upper reservoir, while 85% came from the lower reservoir. The stimulated reservoir volume was about 10 m^3 in the upper reservoir and 250 m^3 in the lower reservoir.

Because the first two wells at Ogachi did not appear to be well-connected, and significant injected water was lost to the reservoir, OGC-3 was drilled in 1999 into fractures indicated from acoustic emissions mapping (Figure 4.12). Borehole televiewer imaging was used to observe fractures in the wellbore, from which better fracture orientations were obtained. Testing also showed an improved response to injection into OGC-1 at OGC-3. One important result of the borehole televiewer imaging, which coincided with the results of enhanced analysis of the acoustic emissions data, was that the upper fractures had a NE fracture orientation while the deeper fractures were oriented NNE (Shin et al., 2000).

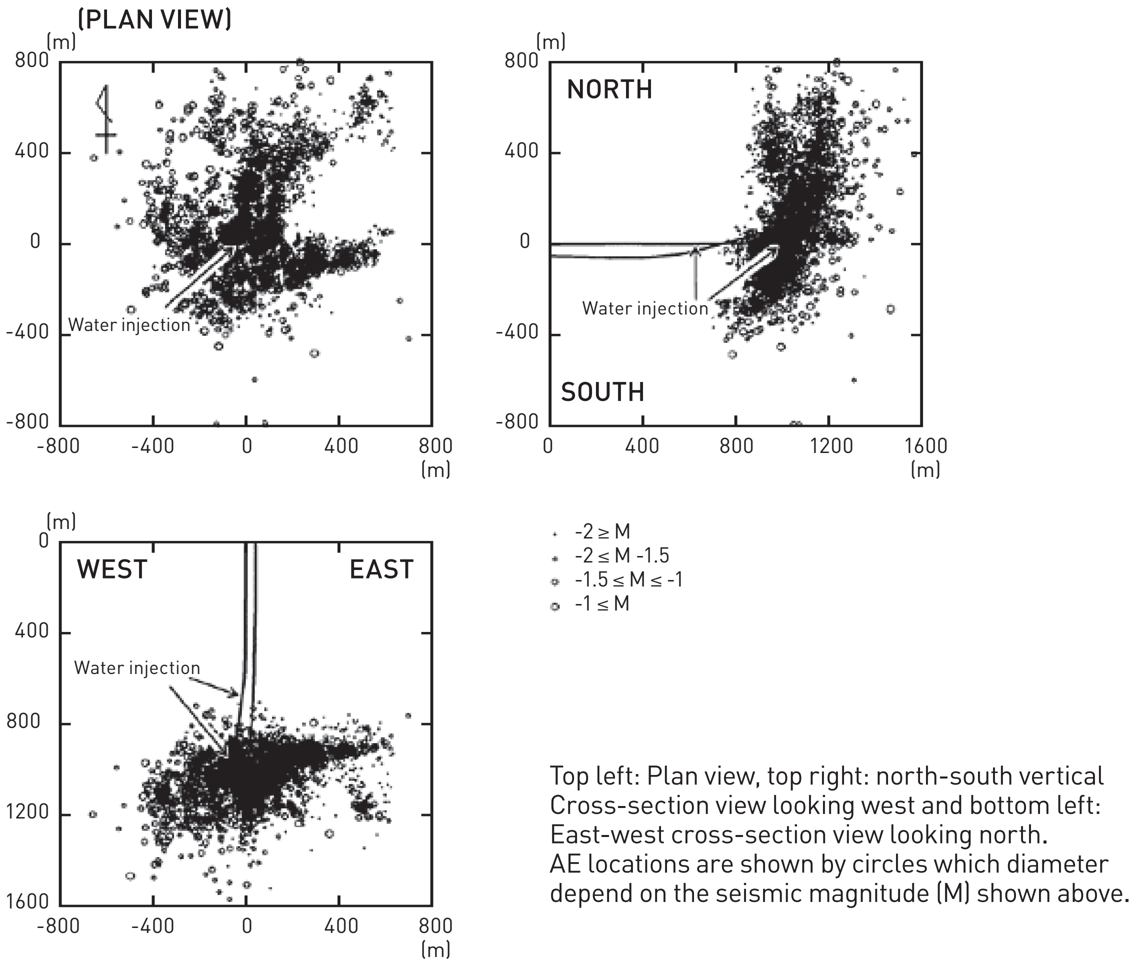

Figure 4.12 Three-dimensional view of the Ogachi reservoir (Kaieda et al., 2000).

4.6.2 Lessons learned at Ogachi

The experience gained at Ogachi – in attempts to fracture between two wells – reinforced observations at Fenton Hill, Rosemanowes, and Hijiori. These projects showed that drilling, stimulating with acoustic emissions, mapping, and then drilling into the fracture cloud yielded the best connection between injector and producers.

- The complex geologic history at Ogachi made it difficult to predict the direction of fracture growth.
- The stress state in the original boreholes was not well understood until borehole televiewer data was collected and analyzed after the wells had been stimulated.
- Drilling OGC-3 into the mapped fractures from acoustic emissions analysis resulted in a significant improvement in connectivity between the wells.
- Efforts to connect the original two wells at Ogachi by stimulating the production well were unsuccessful, after the initial attempts to connect by stimulating the injection well failed.
- While efforts to stimulate the two wells resulted in reservoir growth, they did not result in better connectivity between the wellbores.
- Fluid losses to the reservoir were high during injection testing, because the wells were not well-connected. Once OGC-3 was drilled into the stimulated area, connection was improved and fluid loss was reduced.
- Stress changes with depth in the boreholes (found with borehole televiewers and from improved analysis of the acoustic emissions data) allowed the change in stress direction with depth in the reservoir to be determined.

4.7 Soultz

4.7.1 Project history

As a result of the interest generated by the Fenton Hill project, several European countries began experiments along similar lines. Besides the U.K. project at Rosemanowes, Germany supported two projects – a shallow experiment at Falkenberg, and a deep (4,500 m) single borehole project at Bad Urach. France ran an experiment in 800 m boreholes at Le Mayet in the Massif Central and, together with Germany, began a paper study in the mid-1980s of the potential of a site at Soultz-sous-Forêts in the Upper Rhine Valley (Figure 4.5). As the latter is the site of the former Pechelbron oilfield, the geology was very well characterized, down to about 1,500 m (the top of the granitic basement), and temperature gradients in the upper 1,000 m were known to exceed 110°C/km.

Because HDR technology (as it was then known) was expected to be fairly generic – and the cost of such large-scale experiments is generally quite high – there was general agreement that it would make more sense to pool both financial and manpower resources on a single site. The goal was to develop a European project that eventually would lead to a commercial demonstration.

Under the coordination of the European Commission, a detailed comparison was made of the suitability of the three major European sites (Rosemanowes, Bad Urach, and Soultz); and, in 1987, the decision was made to locate the project at Soultz. Funded initially by the European Commission and relevant energy ministries of France, Germany, and the United Kingdom, a permanent base was established on site with a core team (French, German, and British) to plan the work and coordinate the activities of various research teams from the participating countries. Teams from Italy, Switzerland, and, most recently, Norway, later joined the project; several researchers from the United States and Japan have also contributed.

In 1987, the first well GPK1 was drilled to 2,002 m depth (see Figure 4.13) (after Baria et al., 2005). The drilling performance and experience achieved at Rosemanowes was not applied initially at Soultz. The drilling was difficult (directional control, lost circulation, and stuck pipe were the primary problems), and the budget was overrun. The depth was selected from the extrapolation of the available temperature in the first 1,000 m, leading to an expectation of about 200°C at 2,000 m. The temperature at 2,000 m was actually found to be 140°C, which was caused by convective loops within the granite basement (Baria et al., 2006). The sediment is about 1,400 m thick and it overlays a granitic basement. The majority of the old oil wells were drilled only to about 800–1,000 m depth. The depth to the granite was derived from the interpretation of seismic reflection surveys carried out by oil companies.

In 1988, three existing former oil wells were deepened, so that they penetrated the granite to provide good coupling for seismic sondes – as experience at Rosemanowes had shown to be necessary. A seismic network, based on those used at Rosemanowes and Fenton Hill, was designed and installed.

In 1990, an existing oil well, designated EPS1, was deepened from a depth of 930 m by continuous coring to 2,227 m, where a temperature of 150°C was encountered. Despite drilling problems (largely related to directional control difficulties with coring), which stopped the project from reaching the planned depth of 3,200 m, this gave a very sound characterization of the natural fracture network.

In 1991, GPK1 was stimulated with high flow rates targeting the open-hole section from 1,420-2,002 m. A fractured volume of 10,000 m^3 was created based on microseismic mapping. It is possible that a natural fracture was intersected that stopped fracture growth and allowed for loss of injected fluid. In 1992, GPK1 was deepened from 2,002-3,590 m, reaching a temperature of 168°C. The deepening of GPK1 was successful, and although the contact depth for deepening was 3,200 m depth (anticipated 180°C), the actual depth drilled was 3,590 m because of the use of experienced drilling personnel who had worked in Los Alamos and Rosemanowes. The following year, GPK1 was again stimulated, using large flow rates as used at Los Alamos and Rosemaowes, this time targeting the newly drilled segment from 2,850 to 3,590 m. There was a belief that in a slightly tensional regime like that of Soultz, large-scale injection was not necessary and one could access the flowing network just by improving the connection from the well to the network. This was found not to be true, and large-scale injections were necessary to create the connectivity needed (Baria et al., 1998). GPK1 was then flow-tested in 1994 by producing back the injected fluid.

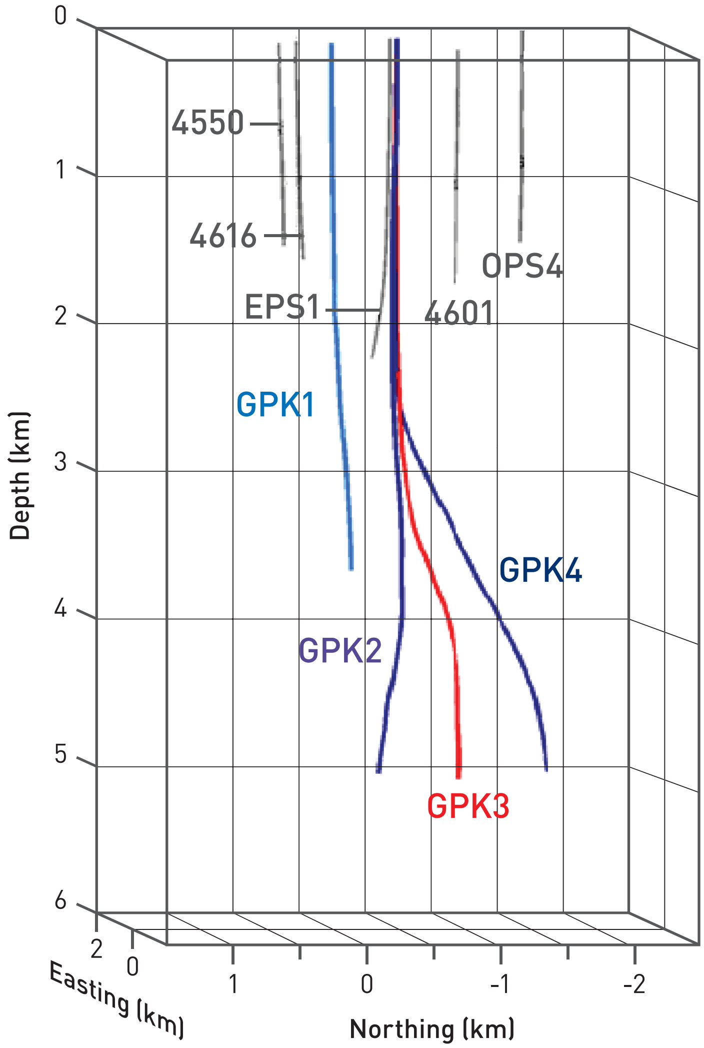

Figure 4.13 Wells drilled at Soultz, France.

Targeting and drilling of GPK2 to 3,876 m at a temperature of 168°C was done in 1995. The bottom-hole location was 450 m from GPK1. During stimulation, analysis of the core and geophysical logs – and fault plane solutions from microseismic events – showed that the rock at 2,000–3,000 m depth contained large numbers of joints and natural fractures. Two joint sets, striking N10E and N170E and dipping 65W and 70E, respectively, dominated the natural fractures observed. Hydro-fracture stress measurements suggested that maximum principal horizontal stress S_H is very close to the principal vertical stress S_V at this depth. The minimum principal horizontal stress S_h is very low and close to the hydrostatic pressure, suggesting that small pressure increases should result in fractures failing in shear. In fact, there are open natural fractures in the wells at 2,210 m and 3,500 m that took fluid before stimulation. The *in situ* reservoir fluid is saline with total dissolved solids (TDS) of about 100,000 mg/l (10% by weight) (Genter et al., 1995).

During 1995, GPK2 was stimulated in the open-hole section from 3,211–3,876 m, with a maximum pressure of about 10 MPa and a flow of 50 kg/s. Acoustic monitoring showed the reservoir growing in a NNW-SSE direction, with a tendency for the fracture cloud to grow upward, forming a stimulated volume of about 0.24 km^3. GPK1 showed a significant pressure response to the stimulation, which showed a connection between the two wells. A two-week circulation test was then performed by injecting into GPK2 and producing from GPK1. The rate was stepped up from an initial rate of 12 kg/s to 56 kg/s (Jung et al., 1996).

During 1995–1996, some circulation tests included the use of an electric submersible pump. With the production well pumped, a circulation rate of more than 21 kg/s was achieved. The surface temperature of the produced water approached 136°C (injection was at 40°C), with a thermal power output of about 9 MWt. The use of a production pump helped maximize power output in this situation, with large open fractures.

In 1996, GPK2 was restimulated, using a maximum rate of 78 kg/s with a total volume of 58,000 m^3 injected. Following this stimulation, in 1997, a four-month, closed-loop flow test was conducted injecting into GPK2 and producing from GPK1. Injection and production stabilized at 25 kg/s, with no net fluid losses. Only 250 kWe pumping power was required to produce the thermal output of 10 MWt.

In 1997–1998, with the aim of gradually transferring the project to industrial management, several new participants were added to the Soultz project, including Shell and several French and German utility companies. With new funding, the decision was made to deepen GPK2 to a TVD of 5,000 m to reach at least 200°C. This required removal of the existing casing, cementing, and reaming out from 6.25 inches to 8.5 inches, and installing new casing to 4,200 m. New high-temperature cement and new metal packers allowed a successful completion of the deepened new GPK2. The predicted temperature of 200°C was measured at a depth of 4,950 m (TVD). An additional acoustic monitoring well, OPS4, was drilled to a depth of 1,500 m and instrumented to improve the accuracy of acoustic event locations. The measurement of the initial, natural prestimulation injectivity of about 0.2 kg/s/MPa in the new deep part of GPK2 was consistent with those seen in the depth range of 3,200–3,800 m.

During the summer of 2000, GPK2 was stimulated using heavy brines to attempt to stimulate the deeper zones preferentially. The overpressure needed to create the large reservoir was lower than anticipated. Nearly 23,400 m^3 water was injected at flow rates from 30 kg/s to 50 kg/s, with a maximum wellhead pressure of 14.5 MPa. The acoustic emissions mapping shows the stimulated reservoir extending NNW/SSE, about 500 m wide, 1,500 m long, and 1,500 m tall. No leak-off to the upper reservoir was detected, and the fact that the majority of the fluid exited the open hole at the bottom during stimulation is very encouraging, because most of the injected fluid enters the well where initial rock temperatures are about 195–200°C.

A number of geophysical logging runs were made to assess the natural and stimulated state of the well. A major conductive fracture set, oriented N160E, was observed from this imagery along with two secondary fracture sets oriented N140E and N20E. All fracture sets dip steeply to the west or east (Moriya et al., 2003).

Starting in 2001, the deep production wells for the high-temperature reservoir were drilled. All of the wells were started from the same pad. GPK3 (see Figure 4.13) was drilled to 5,093 m to target a zone in the stimulated area created from GPK2 in 2000. The bottom-hole separation between GPK2 and GPK3 was 600 m. The bottom zone of GPK3 was stimulated to extend the existing reservoir of GPK2 by an overlapping volume of enhanced permeability.

The deviated well GPK4 (see Figure 4.13) was drilled, starting in August 2003, to a TVD of 5,105 m from the same platform as GPK2 and GPK3 into a target zone selected from the stimulation of GPK3. The bottom of GPK4 was separated from the bottom of GPK3 by about 650 m (a total deviation of some 1,250 m). The well was not completed until early 2004, because of problems with the mud motor, directional control, low rates of penetration, and an accident while running a casing string. During drilling of GPK4, the reservoir was tested by injecting into GPK3 and producing from GPK2. The tests established there was an excellent connection between the two wells with productivity index of 3.5 kg/s/MPa. Pressure response was observed in GPK4 during injection into GPK3.

During testing and stimulation of GPK2 and GPK3, it became more apparent that a small number of induced seismic events were being felt by the local population. No damage was done, but the potential for larger events was unknown, and experiments were conducted to determine what conditions generated the larger events and whether they could be controlled. It was found that by using "soft" shut-ins after injection or production, the number of large events was reduced.

Following completion, GPK4 was stimulated by injecting heavy brine to encourage development of deep fractures. While an area of enhanced reservoir developed, a linear aseismic zone was apparent, separating GPK4 from the other two deep wells. Despite a second stimulation and acidizing, no good connection yet exists between GPK4 and the rest of the reservoir. The injectivity index for this well is good, but the well is not well-connected to the other two.

The aseismic area might be a conductive fracture that prevents pressure buildup, or a barrier to fluid flow of some kind. It appears to limit the connection between GPK4 and the rest of the created reservoir, although the connection has not been thoroughly tested. Other experimental data suggest that it may be possible to inject into more than one well simultaneously to build up pressure in the EGS reservoir far from the wellbores (Baria, 2006). This and other measurements and testing of the connectivity between the wells is planned for the future.

4.7.2 Lessons learned at Soultz

The Soultz project clearly benefited from the experience gained in other HDR/EGS projects, because it successfully created an artificially stimulated reservoir of commercial size, but with production rates still about a factor of 2 or so below required levels for a first-generation economical power plant operation. The Soultz project demonstrated that large fractured volumes could be created repeatedly in rock containing pre-existing natural fractures that are ready to fail in shear.

- Large overpressures are not needed to extend the reservoir, and fairly high productivity and injectivity can be created.
- Natural fractures and the natural connectivity of these fractures seem to dominate the enhanced reservoir system.
- Natural fractures can be stimulated, but there seems to be little data to support the creation of a totally artificial reservoir when no natural fractures are present.
- The point at which stimulation commences in an open wellbore – and then becomes focused – depends on existing conductive fractures, the stress gradient, and fluid density.

- In contrast to what happened at Rosemanowes – where stimulation almost always focused on the bottom of the wells – the upper zones at the Soultz project would stimulate readily when fresh water was used; while, with heavier brines, the lower zones would be stimulated.
- While microseismic monitoring works well overall to map fractures, we still do not completely understand the relationship between mapped acoustic emissions events and fluid flow.
- We can drill deep wells into hard crystalline rock, control their direction, and log them.
- There are aspects of drilling these wells that still need work. Problems with high-temperature mud motors make directional control of deep, high-temperature wells difficult.
- Near-wellbore pressure drop can have a significant impact on the overall pressure drop throughout the system.
- There are several methods for reducing near-wellbore pressure drops such as acidizing, emplacing proppants, and stimulating with fracturing fluids. Further testing is needed to determine which of these is most beneficial.
- Acidizing reduced the injection pressure for a given flow rate but the reason for this is not clear.
- Injection testing shows a nearly linear correlation between wellhead pressure and injection rate. This is typical of flow in porous media in general, suggesting that there was an overall fracturing pattern, not separate discrete fractures. It also reinforces the suspicion that the permeability is not dependent on pressure.
- While injecting at high pressures can increase flow rates during operation of the reservoir, it can also stimulate fracture growth. Another alternative to high-pressure injection is pumping the production well.
- Logging tools have temperature limits, and there is little incentive for oil and gas to raise these limits to very high temperatures.

4.8 Cooper Basin

4.8.1 Project history

Because the entire Australian continent is under large regional overthrust tectonic stress, it was felt that creating a geothermal reservoir by hydraulic stimulation would require high pressures, and attendant high water losses might be a serious issue. However, the large extent of granitic basement (with high heat flow due to radioactive decay) and the large amount of data available to characterize the resource, in some areas, offset such potential difficulties. Initially, the focus on an EGS project was in the Hunter Valley, where energy markets were close. But, in 2002, this focus turned to granitic basement in the Cooper Basin where oil and gas drilling indicated temperatures approaching 250°C at a depth of 4 km (see Figure 4.14).

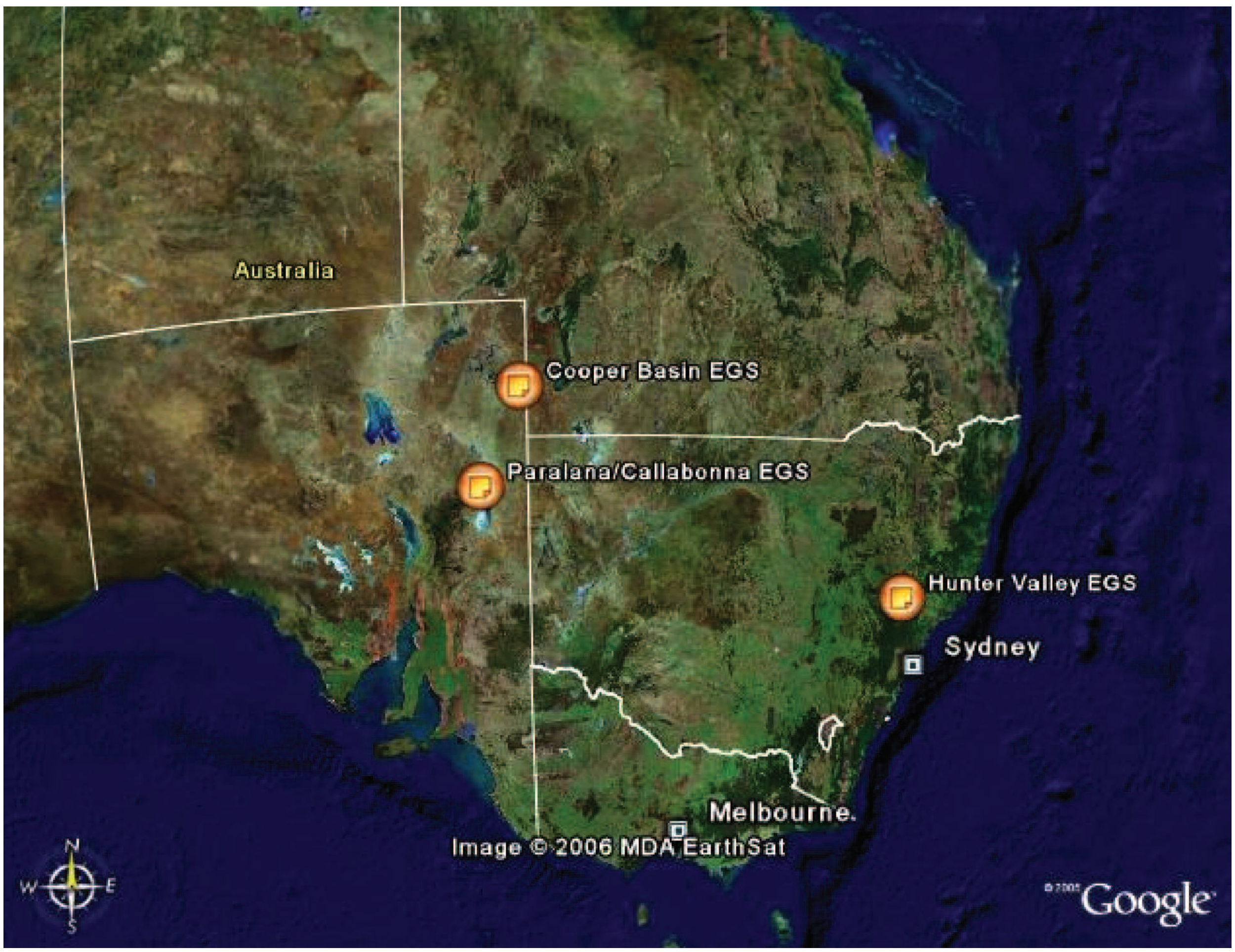

Figure 4.14 EGS sites in Australia (Google Earth).

The Hunter Valley project was started in 1999, under the auspices of Pacific Power (the local electricity utility) and Australian National University. A series of shallow (300 m to 920 m deep) boreholes were drilled over a gravity anomaly, and temperature measurements were made in each borehole. The results of the temperature logging confirmed the existence of the geothermal anomaly and allowed a site to be selected for the drilling of a deeper borehole. This borehole, PPHR1, was drilled to a depth of 1,946 m near the central region of the anomaly, and more than 1 km of continuous core samples were taken to identify the rocks present and their physical properties. The results of the project stimulated commercial interest in Australia's hot dry rock resources to such an extent that a new company, Geodynamics Limited, was successfully floated on the Australian Stock Exchange in 2002. This company has now acquired the Hunter Valley geothermal tenement from Pacific Power. However, Geodynamics' main focus has been the Cooper Basin site.

The Cooper Basin project is in South Australia, due north of Adelaide near the Queensland border (Figure 4.14). The plan for the project is to demonstrate feasibility of an EGS system in an area with large volumes of high-temperature, fairly uniform granitic basement; and to extend the demonstration site to produce hundreds, if not thousands, of megawatts using advanced binary technology.

Cooper Basin contains substantial oil and gas reserves. The regional stress is overthrust, as is much of Australia. A large-scale gravity low in the deepest part of the basin cannot be explained entirely by the basin itself and indicates the presence of granitic basement over an area of at least 1,000 km^2. Oil exploration encountered high-temperature gradients in this area, and several wells intersected granitic basement containing high abundances of radiogenic elements. Three large leased areas known as Geothermal Exploration Licenses (GELs) lie over almost the entire interpreted granitic basement.

Other companies have followed Geodynamics and started exploration for sites to carry out EGS programs, mostly in South Australia. This area is perceived to have many radiogenic granites and other uranium-rich rocks that could lead to high temperatures at relatively shallow depths in the crust. One such location, being developed by Petratherm, is at the Paralana/Callabonna site shown in Figure 4.14; and another is at Olympic Dam in South Australia, being developed by Green Rock Energy.

The first Geodynamics well in the Cooper Basin (injection well Habanero-1) was completed in October 2003 to a depth of 4,421 m near the McLeod-1 well, an oil-exploration well that penetrated granitic basement. Habanero-1, which intersected granite at 3,668 m, is completed with a 6-inch open hole. Data collected from oil and gas wells and from Habanero-1 suggest that the granite is critically stressed for shear failure in a subhorizontal orientation. Some fractures (Figure 4.15) intersected in Habanero-1 were discovered to be overpressured with water at 35 MPa (5000 psi) above hydrostatic pressure. To control the overpressure, the drilling fluids had to be heavily weighted. However, the fractures encountered were more permeable than expected; they also may have failed and slipped, improving their permeability and resulting in drilling fluids being lost into them. The bottom-hole temperature was 250°C.

Following completion of Habanero-1, the well was stimulated in November and December 2003. Pressures up to about 70 MPa were used to pump 20,000 cubic meters of water into the fractures at flow rates stepped from 13.5 kg/s to a maximum of 26 kg/s. This first stimulation created a fractured volume estimated from acoustic emissions data estimated at 0.7 km^3. The stimulation also involved attempts at injecting through perforated 7-inch casing, at depths between 4,136 m and 3,994 m; but only the zone at 4,136 m took substantial fluid and generated microseismic events in new areas. Following the series of stimulations, the fractured volume had expanded to cover a horizontal pancake-shaped area of approximately 3 km^2. The fractured volume forms a rough ellipsoid with the long axis extending in the northeast direction. Habenero-2 was targeted to intersect the fractured reservoir at a depth of 4,310 m, and it did hit the fractures at 4,325 m. During drilling, pressure changes corresponding to wellhead pressure changes in Habanero-2 were observed in Habanero-1.

Some problems encountered during drilling made sidetracking necessary, and a sidetrack to 4,358 m was completed in December 2004. In mid-2005, flow from Habanero-2 was tested, based on the 5,000 psi artesian pressure. Flows of up to 25 kg/sec were measured, and a surface temperature of 210°C achieved. However, testing of the circulation system between the two wells has been delayed, due to lost equipment downhole progressively blocking the flow in Habanero-2.

During September 2005, Habanero-1 again was stimulated with 20,000 cubic meters of water injected and, based on acoustic emissions data, the old reservoir was extended by another 50% to cover an area of 4 km^2.

From April to June 2006, a second sidetrack was attempted using a snubbing unit rather than a drilling rig. The drilling was performed with water instead of a mud system, and encountered problems with slow tripping times, continuous borehole breakout, and downhole equipment failures. The drilling was curtailed with the intention of bringing in a conventional drilling rig by late 2006 to re-establish connection of a production well to the Habanero EGS reservoir.

4.8.2 Lessons learned at Cooper Basin

- Buried radiogenic granite heat sources are ideal in this environment.
- Identifying an extensive body of granite with relatively uniform properties can yield a huge potential heat resource.
- Because the granite was hydrothermally altered, it was relatively easy to drill.
- Water-based overpressure is a surprise, but it assists with stimulation and convective inflow.
- It is difficult to drill multiply fractured zones without underbalanced drilling.
- Subhorizontal fracture zones are present in the granitic basement (either thrust faults or opened unloading features).
- Overthrust stress environments are ideal for stimulation, leading to development of horizontal reservoirs
- Scale-up to multiwell systems on a large scale seems feasible, because of the horizontal reservoir development.
- Scale-up should reduce cost to levels that will compete with other base-load technologies.
- The utility has committed to construction of a transmission line, if economic feasibility can be demonstrated.

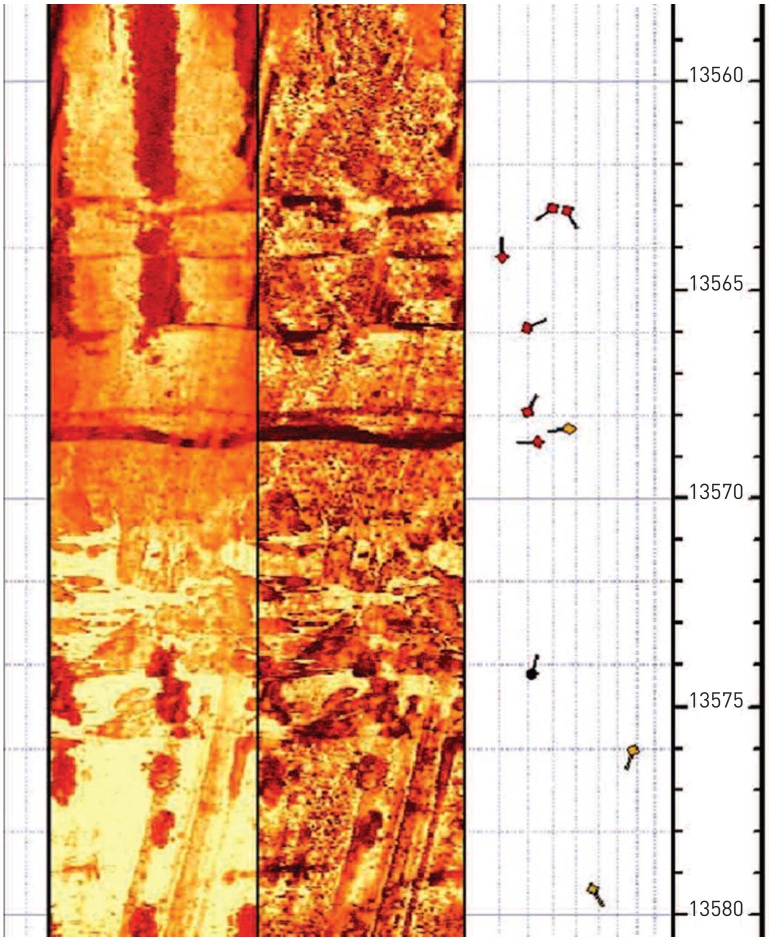

Figure 4.15 Depths in ft of fracture zones at Cooper Basin.

4.9 Other EGS Studies

4.9.1 United States

Current EGS field research in the United States is based at three sites on the margins of operating hydrothermal systems: Coso, Desert Peak, and Glass Mountain/Geysers-Clear Lake. The Coso project was designed to test the ability to fracture low-permeability, high-temperature rocks on the edge of the Coso geothermal area. The project has characterized the resource, tested thermal stimulation of a low permeability well of opportunity, and done baseline studies in preparation for a major hydraulic fracture stimulation in a deep high-temperature well. The Desert Peak project has targeted one well not connected with the Desert Peak geothermal system for stimulation to form an EGS. Political and environmental permitting issues have led to the cancellation of the Glass Mountain project, which targeted low-permeability, high-temperature rocks outside a known hydrothermal system. The industry partner has moved the project to its operating plant in an area in The Geysers with low-permeability, high noncondensable gas, and acidic steam. The new project scope would target stimulation of low-permeability rock on the fringe of the production area to improve steam quality and recharge the reservoir while mining heat.

4.9.2 Europe and Australia

Several sites in Europe and Australia, aside from the projects described above, have been used to test various aspects of EGS technology. The results of these tests and the government-sponsored research conducted at these sites has led to two current projects being undertaken by commercial entities with little or no government support – one at Offenbach, Germany, and the other at Hunter Valley in Australia.

Sweden – Fjällbacka. The Fjällbacka site is to the north of Uddevalla on the west coast of Sweden, where the Bohus granite outcrops. It was established in 1984 as a field research facility for studying hydro-mechanical aspects of HDR reservoir development and for addressing geological and hydrogeological questions. Initially, three boreholes (Fjb0, Fjb1, and Fjb2) were percussion drilled to 200, 500, and 700 m, respectively, to characterize the prospective reservoir. Based on the experiments, and the associated analysis and modeling, some conclusions concerning the hydro-mechanical behavior of the HDR reservoir have been drawn.

A series of shallow (ca. 200 m) and deep-injection tests were conducted to evaluate the response of the virgin rock mass. These culminated in an attempt to develop a reservoir at 450 m depth, by a carefully planned stimulation injection into Fjb1 that featured water, gel, and proppant. Microseismicity was monitored with an array of 15 vertical-component instruments on granite outcrop and a three-component instrument clamped near the bottom of Fjb0. An additional well, Fjb3, was then drilled to 500 m depth in 1988 to intersect a zone of microseismic activity that lay about 100 m to the west of Fjb1. Hydraulic communication between the wells was successfully established, although flow tests indicated the presence of an impedance to flow in the vicinity of Fjb3. Thus, a stimulation injection into Fjb3 was conducted, and succeeded in reducing the flow impedance, at least in the near field. A 40-day circulation of the system was conducted in 1989. Results are summarized as follows:

- Highly detailed reservoir characterization led to a detailed design of the stimulation program.
- Located in a tectonic shield structure – where the state of stress at reservoir depth is such that the least principal stress is vertical – horizontal fractures form the preferred paths for fluid flow.
- The hydraulic stimulation in Fjb1 resulted in a distinct increase in transmissivity in the stimulated reservoir section, and potential stimulation effects to about 100 m from this well.
- The evidence of penetration of stimulation fluid, at least to this distance where intense microseismic activity was located, is indisputable. But the relation between seismic shear events and fracture-permeability increase is still insufficiently understood.
- Hydraulic jacking is expected to have occurred in the fractures close to the injection well.
- Natural fractures dominate the stimulation result.
- The microseismic locations were used to target the second well of the HDR doublet, and the results clearly suggest that the regions of seismicity are linked with permeability enhancement and major fluid flow.
- The reservoir provides fairly conductive paths between the wells, but the impedance to flow and fluid losses are too high to enable an economically acceptable circulation and heat-extraction process.
- There seem to be comparatively few hydraulically active fractures linking the major permeable zones in the two wells. However, at this shallow depth, the fracture system is essentially subhorizontal and not representative of behavior at greater depths.

Germany – Falkenberg. The Falkenberg test site was established in northeastern Bavaria in 1978, at a location where the Falkenberg granite essentially extends to the surface. The aim was to conduct fundamental *in situ* hydro-mechanical experiments at small depths with a high degree of observational control, which would be relevant to the understanding of HDR systems. The research program at Falkenberg lasted until 1983 (Tenzer, 2001).

The principal experiments were aimed at determining the hydro-mechanical properties that hydro-fractures created in joint-free portions of the wellbore. A large-scale zone was stimulated using packers in an interval free of joints in the drillhole HB4a in the depth range 252-255 m. Six further boreholes intersected the fracture that propagated during this stimulation. The creation of the hydro-fracture itself is of particular interest, because it proved that fresh hydro-fractures can be propagated over significant distances in fractured crystalline rock. This was contrary to the conventional wisdom that said fluid leak-off into the natural fracture system would prevent this from happening.

The fracture was initiated in 1979 by injecting 6 m^3 of water into borehole HB4a at a rate of 3.5 kg/s, with a breakdown pressure of 18 MPa. Assuming a penny-shaped crack geometry and allowing for leak-off, a fracture radius at shut-in of 44 m and a maximum width of 0.62 mm are inferred. Televiewer images of the induced fracture obtained in several neighboring boreholes indicate multiple parallel fractures near the injection borehole, although it seems that only one of these extended beyond 20 m. At borehole PB8 – about 2 m from the injection point – eight parallel fractures are evident within a zone 1.3 m thick; whereas, at 11 m (borehole SB5), only two fracture traces are evident. At more distant boreholes, ranging up to 50 m from the injection well, only one fracture trace is visible.

Multiple fracture growth is commonly seen in sedimentary rocks, where it is often associated with high flow impedance. Microseismicity occurring during the injections was monitored by four downhole, three-component seismometers installed in neighboring boreholes. The successful detection of 16 of the induced events concurs with the intersection depth of the created fracture and the boreholes, suggesting a planar structure that strikes E-W, dipping 45° to the south. The fracture was extended in 1981 with a 33 m^3 injection, and again in 1983 with 52 m^3. Numerous inflation/deflation cycles were made during the intervening periods, though always involving volumes smaller than the previous "extension" injection.

An extensive program of hydraulic tests was undertaken during the project run time. The longest was a 14 h circulation at 3.4 kg/s, during which a thermal drawdown of 1°C was determined. The variation of fracture hydraulic aperture and transmissivity as functions of inflation pressure were investigated and compared with measurements of mechanical aperture taken with a specially developed caliper sonde.

- In the Falkenberg project, a fracture believed to be artificial was stimulated from a well (HB4a) at a depth of 450 m.
- Seven additional wells were subsequently drilled in a pattern above the fracture.
- Several of these wells intercepted the fracture to the extent that small amounts of water could be circulated through the fracture, and extensive hydraulic and rock mechanical experiments could be conducted.

- Among other findings, the Falkenberg experiments proved that hydraulic pressure alone could keep joints open.

Germany – Bad Urach. Between 1977 and 1980, a large-scale investigation was undertaken of the geothermal anomaly around the area of Urach, in the Swabian Alps, approximately 50 km south of Stuttgart. In addition to examining the scale and nature of the anomaly, the intention was to assess the possibility of utilizing hot aquifers for heating purposes, and also to examine the basement rocks with the view toward future extraction of geothermal energy through HDR (Tenzer, 2001).

The work was conducted by the Forschungs-Kollegium Physik des Erdkörpers (FKPE), a group comprising academic and government research institutes. This group worked in conjunction with a group from the town of Bad Urach, whose objectives were to investigate the availability of hot aquifers for expansion of the spa operation, as well as other applications.

Early work consisted of an intensive geophysical and geological survey of the area. This included the drilling of two 800 m deep geothermal exploration boreholes (Urach I and II), in 1970 and 1974, into the Middle Triassic Muschelkalk formation. In October 1977, drilling began on a deep exploration borehole, Urach III. This was completed after 231 days of drilling, reaching a target depth of 3,334 m and penetrating approximately 1,700 m into the crystalline basement. Drillcore was obtained over approximately 7% of the crystalline section. In 1983, the uncased section of Urach III was extended to 3,488 m. Subsequent testing included BHTV logging and a single hydro-fracture stress measurement at 3,350 m depth.

A series of small-scale stimulations with subsequent fluid circulation occurred between May and August 1979. During the course of these experiments, a mica-syenite section of the crystalline basement was stimulated seven times over four depth intervals: one open-hole section and three zones accessed through perforated casing. The stimulations carried out through the three zones of perforated casing involved the use of viscous gel and proppant. The perforated sections had a vertical separation of only 70 m. A circulation loop was established between the open-hole stimulated section (3,320 m–3,334 m) and the cased-hole stimulation between 3,293 m–3,298 m depth. A total of 12 circulation tests were attempted, the most successful of which lasted six hours and 12 hours (Tenzer, 2001).

Over the depth range of the HDR stimulation and circulation experiments (in the mica-syenite between 3,250 and 3,334 m), the fracture density was of the order 0.7 per meter. These open fractures were reported as having encrustations of calcite and pyrite, while the closed joints were largely filled with quartz. It was further noted that the fracture dips ranged from 40°–70°.

Limited *in situ* stress data have been provided by borehole breakouts, by a single hydraulic fracturing stress measurement (HFSM), by fracture inflation pressures, and by the orientation of drilling induced fractures. Breakouts identified over the depth range of 3,334 m to 3,488 m exhibited a consistent trend of approximately 82°, indicating a maximum horizontal stress orientated at 172°. This result is consistent with the observed strike of drilling-induced, subvertical extension fractures observed in Urach III.

The value of minimum horizontal stress derived from the single HFSM (3,350 m) lies between 42 and 45 MPa. The derived value of the maximum horizontal stress is about 88 MPa, which is very close to the likely value of the overburden stress at 3,350 m. In summary:

- The stimulation connected one section to another in a single borehole.
- Circulation was established across a section with only 70 m of separation
- This concept was later used for the single-well concept at Horstberg. For direct-use applications where only low flows are needed, this can reduce the cost of the installation.

Switzerland – Basel and Geneva, Deep Heat Mining. The Deep Heat Mining (DHM) projects underway in Switzerland plan to generate power at sites in Basel and Geneva within the next 10 years (Tenzer, 2001). At Basel, a 2.7 km exploration well was drilled and studied, and is now being equipped with seismic instrumentation. At the Geneva site, detailed investigations are being conducted to site the first exploratory well. A unique aspect of the Basel project is that drilling is taking place within city limits, and the heat produced by the system has the potential for direct use as well as electrical generation. The projects were initiated in 1996 and are partly financed by the Federal Office of Energy (OFEN). Private and public institutions support the activities of the project.

In Basel, Switzerland, a pilot plant is being developed to use energy extracted by EGS technology for cogeneration of electrical power and heat for local district heating. The core of the project, called Deep Heat Mining Basel, is a well triplet into hot granitic basement at a depth of 5,000 m. Two additional monitoring wells into the top of the basement rock will be equipped with multiple seismic receiver arrays. They will record the fracture-induced seismic signals to map the seismic active domain of the stimulated reservoir volume. Reservoir temperature is expected to be 200°C. Water circulation of 100 kg/s through one injection well and two production wells will result in 30 MW of thermal power at wellheads. It has not yet been decided what conversion cycle will be used for electric power production. The plant is in an industrial area of Basel, where the waste incineration of the municipal water purification plant provides an additional heat source. In combination with this heat source and an additional gas turbine, a combined cogeneration plant can produce annually up to 108 GWh of electric power and 39 GWh of thermal power to the district heating grid.

Basel is not only situated at the southeastern end of the Rhine Graben, but also at the northern front of the Jura Mountains, the outermost expression and youngest part of the Alpine fold belt. The peculiar coincidence of north-northwest trending compression and west-northwest extension creates a seismically active environment.

The geothermal reservoir and the power plant will be located within this seismically active area. Therefore, it is important to record and understand the natural seismic activity as accurately as possible, prior to stimulation of a deep reservoir volume, which is characteristically accompanied by induced seismicity. The first exploration well, Otterbach 2, was drilled in 2001 into granitic basement at 2,650 m, to a total depth of 2,755 m. The well is planned to become a monitoring well to record regional seismic events, as well as the stimulation events.

Borehole deformation logging using acoustic and electric borehole televiewer tools shows induced fractures pointing predominantly in a NNW direction, and induced borehole breakouts in the perpendicular direction. This trend is precisely in line with the regional stress field. No pressure tests were performed. The well was drilled with a balanced mud system. The fact that induced fractures are observed already in a balanced well indicates that fracturing in the granite will not require large hydraulic pressures. The EGS project of the European Community at Soultz-sous-Forêts, 150 km north (also situated in the Rhine Graben), experienced similar conditions. In an injection test over a period of 126 days, with flow rates around 25 kg/s through a reservoir at 3.5 km depth, injection pressures averaged 3 MPa.

The next well is planned to the targeted reservoir depth of 5,000 m. It will be drilled on an industrial site in the city of Basel. It is intended to deviate the well at a depth of 3,000 m to the east, with an angle of 15°, in order to improve chances to penetrate open fractures associated with the main boundary fault system.

When the main targets of a minimum temperature of 190°C and a fractured reservoir rock are found in a favorable stress field, the well will be suspended. A second monitoring well at 2 km to the east will then be drilled and equipped with a seismic array similar to the Otterbach well. The two extended seismic arrays provide a series of locally independent receiver points, sufficient to compute the location of a seismic source with the required accuracy. Subsequently, injection tests will be conducted in the deep well in order to develop an EGS reservoir.

The final two deep wells will be directionally drilled from the same location. The conversion cycle for power production will be selected following proof of circulation. The exploration phase (proof of circulation) should be completed within two years. Besides the technical challenges to stimulate a fracture system along a fault system in a seismically active area, other environmental challenges, such as drilling-noise mitigation in a city, have to be met.

- This project will be the first project to demonstrate the use of EGS technology to produce both heat and power.
- The wells are drilled in the city of Basel in an industrial part of town, and demonstrate the potential for coexistence of EGS projects with other industrial activities within city limits.
- Drilling problems in the sedimentary section were caused by swelling clays and often led to stuck drill pipe. Problems were encountered in the crystalline basement as well.
- Because of the location of the wells under a city center, the potential for damage from a major seismic event associated with stimulation and production is greater than in rural areas.

France – Le Mayet de Montagne. The Le Mayet site is 25 km east-southeast of Vichy, France, at the northern fringe of the Massif Central. Granite extends to the surface, forming undulating topography of height less than 100 m, and offering exposures of fractures in outcrop. Rock- and hydro-mechanical aspects of the problem of exploiting hot dry rock (HDR) reservoirs have been studied. In the late 1980s, two, near-vertical boreholes were drilled approximately 800 m deep and 100 m apart along a line striking N140E. Well 111-8 (780 m depth) lies to the northwest of 111-9 (840 m depth). Borehole packers were used to isolate a number of locations over a span of several hundred meters for multiple stimulation experiments, producing a localized hydraulic linkage of large surface area between the two wells.

The experiments involve high flow-rate (20-30 kg/s) stimulation of selected intervals (with and without proppant), conventional hydro-fracture stimulations (73 kg/s), and long-term circulations tests. Microseismic events induced during these experiments were monitored on a 15-station array (mostly three-component with two downhole) that allowed event locations to be determined to within 4.5 m horizontally and 10 m vertically. The seismic data set featured the best sampling of the seismic radiation field attained at that time in a HDR field experiment. More than 35 events were recorded on sufficient stations to yield fairly well-constrained focal mechanism solutions. The analysis of these focal mechanisms is particularly interesting, because they are used to constrain the local stresses driving fracture failure. Another novel aspect of the work at Le Mayet was the deployment of an array of tiltmeters to monitor surface deformation occurring in response to fluid injection. This deformation reflects the elastic field resulting from dilation of the joints/fractures, and should be detectable if fractures dilate as much as conventional theory predicts. In summary:

- Borehole packers were used to isolate several zones, so that a succession of stimulated zones was created.
- The result was a large-scale fractured heat-exchange area with good connection between two boreholes.
- Tiltmeters were successfully used to monitor the growth of fractures.

Germany – Horstberg. Due to their low transmissivity, most sedimentary formations in the northern German basin are not considered for the extraction of geothermal energy. To overcome these limitations, the GeneSys-project was initiated at the GEOZENTRUM, Hannover (Behrens et al., 2006). It is intended to investigate concepts that allow the use of the widespread low-permeability sediments for geothermal energy extraction and, ultimately, to supply heat for the complex of buildings of the GEOZENTRUM, Hannover. The hydraulic-fracturing technique successfully applied in crystalline rocks for the creation of HDR systems will be used to create large-scale fractures covering areas in the order of km^2 in the sediments to increase the productivity of the well to the required flow rates. Because a thermal power of approximately 2 MWt is required for the supply of the GEOZENTRUM, only relative low production rates are required, which can be realized with a one-well concept. Such a concept, where the well is simultaneously used for production and reinjection, can be operated economically even for a relatively low power output of a few MWt. This production is suitable for providing heat to large buildings, or districts, where a district heating system is available.

To test concepts, a series of *in situ* tests were conducted in the abandoned gas exploration well Horstberg Z1. The well is operated as an *in situ* laboratory by BGR (Federal Institute for Natural Resources and Geosciences), which belongs to the GEOZENTRUM, Hannover. The experiments started in September 2003. The originally proposed concept envisioned that, by the creation of large fractures, the well would be connected to water-bearing joints, faults, fracture zones, or porous layers not directly accessed by the borehole. The hot water produced from these structures would be injected, after cooling, via the annulus of the same borehole into a permeable rock formation at shallower depth.

Massive hydro-frac tests were performed in a sandstone layer of the Buntsandstone formation at a depth of approximately 3,800 m, by injecting more than 20,000 m^3 of fresh water at flow rates up to 50 kg/s, and at wellhead pressures of about 33 MPa. Post-frac venting tests showed that the created fracture has a high storage capacity (about 1,000 m^3/MPa) and covers an area of several hundred thousand square meters, indicating that the fracture not only propagated in the sandstone layer, but also fractured the adjacent clay-stone horizons. They also showed that the fracture, or at least part of the fracture, stayed open during pressure release, thus allowing venting flow rates of about 8.3 kg/s, at fluid pressures well below the frac-extension pressure. Long-term extrapolations of the venting flow rate, however, showed that the desired flow rate of 6.9 kg/s cannot be maintained over a prolonged time period, because the production and reinjection horizons (at 1,200 m depth) do not communicate, and the overall yield of the formation accessed by the fracture is too low.

The results of cyclic tests, consisting of a cold-water injection period, a warm-up period, and a venting period were very promising. The fluid volumes and production temperatures achieved during these tests show that this can be an alternative concept for heat extraction from tight sedimentary rock.

To monitor microseismicity induced during stimulations, a seismic network was installed. It consists of eight stations installed on two circles with radii of 800 and 1,600 m, centered around the well position at depth and a surface array of 60 geophones. At each of the stations, a 100 m deep well was drilled, and geophones were installed permanently at the bottom of these wells. Data were analyzed on-site with respect to the occurrence of microseismicity. In contrast to hydro-frac tests in crystalline rock, where several thousands or tens of thousands of microseismic events were detected and located with networks of comparable sensitivity, only a few events were detected here. A reliable source location could not be inferred for any of these events.

The experiences gained within the project, however, are highly relevant for the oil and gas industry in the Northern German Basin, because they have a lively interest in seismic monitoring of stimulation operations. To sum up:

- This project demonstrates the benefits of stimulation in a sedimentary environment – large storage coefficient and pre-existing permeability.
- The concept of using a single borehole was not effective, because there was no connection between the injection zone and the production zone, so the production zone was not recharged and could not support long-term production.
- Few microseismic events were detected during stimulation and circulation tests, especially compared to the large number of microseismic events generated and detected during stimulation in crystalline rock.

4.10 Generalizations from EGS Field Testing

Progress in improving the technology needed to produce commercial-scale EGS reservoirs has been dramatic in the past few years. We have long been able to drill the wells, stimulate the rock to improve tranmissivity, target wells into the stimulated volume, and make a connection between producer and injector. We can circulate the fluids for long time periods, from months to more than one year, at reasonably high rates, 10-30 kg/s. When measurable temperature drops were observed, they were correlated with the size of the stimulated reservoir using a range of thermal hydraulic modeling approaches (for example, see Tester and Albright, 1979; Armstead and Tester, 1987; and Tester et al., 1989). Figure 4.16 shows the produced thermal energy output for several major EGS projects spanning 30 years. In addition, projections are shown for current EGS projects in the United States, Europe, and Australia. We can monitor the stimulation to map the fractured volume – we can map fractures in the borehole, log the wells for temperature and pressure to a very high degree of accuracy, and determine stress state from borehole data.

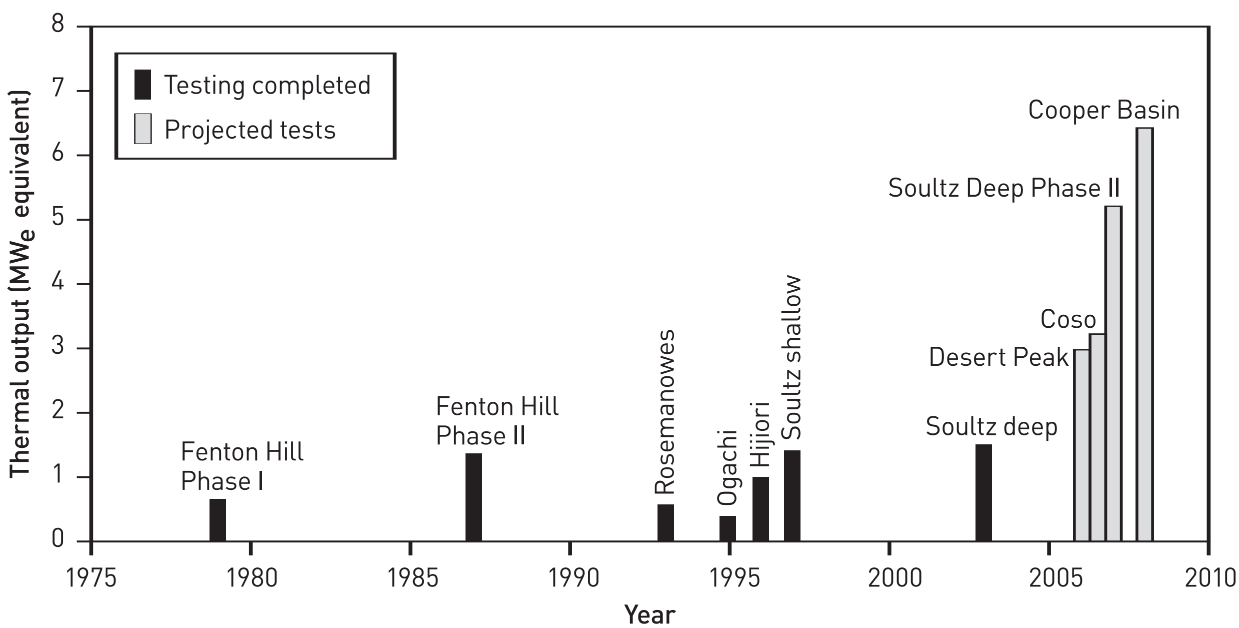

Figure 4.16 Evolution of estimated electrical power output per production well, with time from EGS projects. The Fenton Hill, Coso, and Desert Peak projects received, or are receiving, major funding from the U.S. DOE.

Lessons Learned from Natural Hydrothermal Systems. The basic EGS techniques of permeability enhancement, heat mining, and injection augmentation already work. They are regularly used in regions where the natural fractures support flow and connectivity, but where recharge is limited. At Mahangdong (Yglopaz), and Mindanao (Ramonchito) in the Philippines; and two sites in Indonesia; as well as Coso, (Petty, personal communication), The Geysers, East Mesa, and Steamboat in the United States (Petty, personal communication), hydraulic stimulation, with or without acidizing, has resulted in increased permeability. At East Mesa, cooling of the resource after more than 10 years of operation was reduced or halted by moving injectors or drilling new ones, shutting off zones of thermal breakthrough by recompleting wells, and by changing pump-setting depths to produce preferentially from zones with higher temperatures. At The Geysers, drying of the reservoir, increase in noncondensable gases, and pressure drawdown with little or no natural recharge were addressed by bringing treated waste water from the city of Santa Rosa and from Lake County, for injection augmentation. At Dixie Valley, pressure drawdown due to lack of natural recharge and limited injection into the reservoir was reversed by injecting all produced fluids, careful selection of injector locations, and augmentation of injection from shallow, non-potable groundwater sources on site.

- *High flow rates with long path lengths are needed*. By looking at natural hydrothermal systems, we know that we need to have production of about 5 MW_e per production well, which requires flow rates ranging from 30 to 100 kg/s, depending on the fluid temperature. At the same time, we need a large heat-exchange area or long residence time for water to reheat to production temperatures; this could imply large pressure drops. Better understanding of successful natural systems (in comparable geological settings) should lead to improved methods of generating artificially enhanced geothermal systems. For instance, the residence time of water injected at Dixie Valley is three-six months, and the production wells show little or no cooling due to the aggressive injection program. At Steamboat, though, the residence time for the water is closer to two weeks and there is fairly significant cooling. The well spacing between injectors and producers at Dixie Valley is about 800 m, and there are probably at least two fractures with a somewhat complex connection between the injectors and producers resulting in a long fluid-path length. At the Steamboat hydrothermal site, the distance between producers and injectors is more than 1,000 m; but because there are many fractures, the transmissivity is so high that there is low residence time for injected fluids. At the East Mesa hydrothermal site, the reservoir is in fractured sandstone, and the residence time varies from one part of the field to another. Some injectors perform well in the center of the field, while other injectors are in areas with either high matrix permeability in some zones or fractures that cause cold water to break through faster. The large volume of hot water stored in the porous matrix at East Mesa made it possible to operate the field for a long time before problems with cooling developed.

- *Stimulation is through shearing of pre-existing fractures*. In strong crystalline rock, hydraulic properties are determined by the natural fracture system and the stresses on that fracture system. The expectation of scientists planning the early experiments in enhancing geothermal reservoirs was that fracturing would be tensile. While it may be possible to create tensile fractures, it appears to be much more effective to stimulate pre-existing natural fractures and cause them to fail in shear. Understanding the orientation of the stress field is crucial to designing a successful stimulation. Fortunately, in even the most unpromising tectonic settings, many fractures seem to be oriented for failure. At Cooper Basin, which is in compression, stimulation of two nearly horizontal pre-existing fracture systems appears to have been successful in creating a connected reservoir of large size. Shearing of natural fractures increases hydraulic apertures, and this improvement remains after pressures are reduced. Fortunately, stress fields in strong rocks are anisotropic, so critically aligned natural joints and fractures shear at relatively low overpressures (2-10 MPa).

- *Fractures that are stimulated are those that will take fluid during pre-stimulation injection*. The fractures that are found to be open and capable of receiving fluid during evaluation of the well before stimulation are almost always those that are stimulated and form large-scale connections over a large reservoir volume. This may be because these fractures are connected anyway, or because the fractures that are open are those oriented with the current stress state. It is important, therefore, to target areas that will have some pre-existing fractures due to their stress history and the degree of current differential stress. But even in areas with high compressional stresses – such as Cooper Basin in Australia – there are natural, open fractures. However, with present technology, we cannot create connected fractures where none exist. It may be possible to initiate new fractures, but it is not known whether these will form large-scale flow paths and connect over large volumes of the reservoir. This means that the fracture spacing in the final reservoir is governed by the initial, natural fracture spacing. The number of fractures in a wellbore that will take fluid is, therefore, important to assess in each well. The total heat that can be recovered is governed by the fracture spacing, because the temperature drops rapidly away from the fracture face that is in contact with the injected cool fluid.

- *We currently do not have a reliable open-hole packer to isolate some zones for stimulation*. This is routine in the oil and gas industry; but in the geothermal industry, high-temperature packers for the open hole are not reliable, so we stimulate the entire open interval. Logging shows that the first set of open fractures is the one most improved. If we want to stimulate some zones more than others – or if we want to create new fractures – we will need a good, reliable, high-temperature open-hole packer. Although earlier testing at Soultz using a cement inflatable aluminum packer have been encouraging, more development work remains to be done to improve reliability and increase temperature capability.

- *Hydraulic stimulation is most effective in the near-wellbore region*. The near-wellbore region experiences the highest pressure drop, so stimulation of this region is important. But we also need connectivity in the far field away from the wells to maintain circulation and accomplish heat mining. We can effectively use a variety of techniques both from the oil and gas industry and from geothermal experience to improve near-wellbore permeability. Hydraulic stimulation through pumping large volumes of cool fluid over long time periods, and acidizing with large volumes of cool fluid and acid (of low concentration), have been most effective. Use of high-viscosity fluids, proppants, and high-rate high-pressure stimulation has been tried with mixed success and may still have potential in some settings, particularly in sedimentary reservoirs with high temperatures. However, there are limits to the temperature that packers, proppants, and fracturing fluids can withstand, so some of these techniques are impossible or very costly in a geothermal setting. In crystalline rocks with pre-existing fractures, oil and gas stimulation techniques have failed to result in connection to other fractures and may form short circuits that damage the reservoir. Our current efforts to stimulate geothermal wells and EGS wells, in particular, are limited to pumping large volumes of cold water from the wellhead. This means that the fractures that take fluid most readily anyway are stimulated the most. Only a small portion of the natural fractures seen in the wellbore support flow. Because these more open fractures may also be the ones that connect our producers to our injectors, this may not be a disadvantage. However, there may be a large number of fractures observed in the wellbore, and an ability to identify and target the best ones for stimulation is limited because of a lack of research.

- *The first well needs to be drilled and stimulated in order to design the entire system*. Early efforts to create reservoirs through stimulation relied on drilling two wells, oriented such that there appeared to be a good chance of connecting them, given the stress fields observed in the wellbore and the regional stress patterns. However, at Fenton Hill, Rosemanowes, Hijiori, and Ogachi, this method did not yield a connected reservoir. Stress orientation changes with depth, or with the crossing of structural boundaries, and the presence of natural fractures already connected (and at least somewhat permeable) makes evaluating the stimulated volume difficult. It seems much easier to drill the first well, then stimulate it to create as large a volume as possible of fractured rock, then drill into what we think is the most likely place, and stimulate again. Because of this, we can design wells as either producers or injectors, whereas it would be better if we could design wells for both production and injection. This emphasis on the first well demands that it be properly sited with respect to the local stress conditions. Careful scientific exploration is needed to characterize the region as to the stress field, pre-existing fractures, rock lithology, etc.

- *Monitoring of acoustic emissions is our best tool for understanding the system*. Mapping of acoustic events is one of the most important tools we have for understanding the reservoir. In hydrothermal systems, we know from well tests and tracer tests that water is circulating and in contact with large areas of rock. We can assess stimulated fractures in the same way, once we have two or more wells in hydraulic connection to allow for circulation tests. We can map the location of acoustic emissions generated during stimulation and during circulation extremely accurately, i.e., +/- 10-30 m. While we are not completely sure what the presence or absence of acoustic emissions means in terms of fluid flow paths or reservoir connectivity, knowledge of the location and intensity of these events is certainly important. This information helps define targets for future wells.

  If we drill into a zone that has already been stimulated and shows a large number of acoustic emissions events, it is commonly assumed that the well is connected to the active reservoir. However, this fact does not always result in a good system for heat extraction. For example, at Soultz, GPK4 was drilled into an area that was within the volume of mapped acoustic emissions, but it did not produce a connected fracture system between the production and injection wells, even after repeated stimulations. Mapping of acoustic emissions has improved, so that we can locate acoustic emissions and determine the focal mechanism for these events more accurately than in the past. As a result, we can better understand the stress field away from the wellbore and how our stimulation affects it.

  Methods for mapping fractures in the borehole have been developed, and the upper limit for temperatures at which they can operate is being extended. Ultrasonic borehole televiewers, microresistivity fracture imaging, and wellbore stress tests have all proved very useful in understanding the stress state, nature of existing fractures, and the fluid flow paths (before and after stimulation). Correlating the image logs with high-resolution temperature surveys and with lithology from core and cuttings allows a better determination of which fractures might be productive.

- *Rock-fluid interactions may have a long-term effect on reservoir operation*. While studies of the interaction of the reservoir rock with the injected fluid have been made at most of the sites where EGS has been tested, there is still a good deal to learn about how the injected fluid will interact with the rock over the long term. The most conductive fractures often show evidence of fluid flow in earlier geologic time such as hydrothermal alteration and mineral deposition. This is encouraging in that it suggests that the most connected pathways will already have experienced some reaction between water and the rock fracture surface. Fresh rock surfaces will not have the protection of a layer of deposited minerals or alteration products. We also do not know how much surface water (which cannot be in equilibrium with the reservoir rock) we will need to add to the system over the long term. Our longest field tests have seen some evidence for dissolution of rock leading to development of preferred pathways and short circuits. Regardless, we will cool the produced fluid through our surface equipment, possibly resulting in precipitation of scale or corrosion (Vuatarez, 2000).

  Although not analyzed in this study, the use of carbon dioxide (CO_2) as the circulating heat transfer fluid in an EGS reservoir has been proposed (Pruess, 2006). Brown (2000) has developed a conceptual model for such a system, based on the Fenton Hill Hot Dry Rock reservoir. The argument is made that supercritical CO_2 holds certain thermodynamic advantages over water in EGS applications and could be used to sequester this important greenhouse gas. We also address this topic in Section 8.3.3.

- *Pumping the production well to get the high-pressure drops needed for high flow rates without increasing overall reservoir pressure seems to reduce the risk of short circuiting while producing at high rates*. High pressures on the injection well during long-term circulation can result in short circuits. Circulating the fluid by injecting at high pressures was found to consume energy while, at the same time, tending to develop shorter pathways through the system from the injector to the producer. High-pressure injection during circulation also may cause the reservoir to continue to extend and grow, which may be useful for a portion of the time the field is operating – but may not create fractures that are in active heat exchange, given the system of wells that are in place. High-pressure injection can also result in fluid losses to those parts of the reservoir that are not accessed by the production wells. However, by pumping the production wells in conjunction with moderate pressurization of the injection well, the circulating fluid is drawn to the producers from throughout the stimulated volume of fractured rock, minimizing fluid loss to the far field.

- *The wells needed to access the stimulated volume can be targeted and drilled into the fractures*. While drilling deep wells in hard, crystalline rock may still be fairly expensive, the cost technology has improved dramatically since the first EGS wells were drilled at Fenton Hill. Drill bits have much longer life and better performance, typically lasting as long as 50 hours even in deep, high-temperature environments. The rate of penetration achievable in hard, crystalline rock and in high-temperature environments is continually increasing, partly due to technology developments with funding from the U.S. government. As the oil and gas industry drills deeper, and into areas that previously could not be drilled economically, they will encounter higher temperatures and more difficult drilling environments. This will increase the petroleum industry's demand for geothermal-type drilling. Most geothermal wells need to have fairly large diameters to reduce pressure drop when flow rates are high. Directional control is now done with mud motors, reducing casing wear and allowing better control. Although high temperatures are a challenge for the use of measurement-while-drilling (MWD) tools for controlling well direction, they did not exist when the first EGS well was drilled at Fenton Hill. Furthermore, the temperature range of these tools has been extended since they first became available. Mud motors are now being developed that can function not only at high temperatures, but also with aerated fluids. See Chapter 6 for further discussion.

- *Circulation for extended time periods without temperature drop is possible*. Although early stimulated reservoirs were small, and long-term circulation tests showed measurable temperature drop, later reservoirs were large enough that no temperature drop could be measured during the extended circulation tests. It is difficult to predict how long the large reservoirs will last, because there is not enough measurable temperature change with time to validate the numerical models. Tracer test data can be used for model verification (see Chapter 5, Figure 5.3), but in cases where extremely large reservoirs have been created, tracer data may not be adequate for determining the important parameters of heat-exchange area and swept volume.

- *Models are available for characterizing fractures and for managing the reservoir*. Numerical simulation can model fluid flow in discrete fractures, flow with heat exchange in simple to complex fractures, in porous media and in fractured, porous media. Changes in permeability, temperature changes, and pressure changes in fractures can be fit to data to provide predictive methods. However, because long-term tests have not been carried out in the larger, commercial-sized reservoirs, it is not yet known whether the models will adequately predict the behavior of such reservoirs. Rock-fluid interactions in porous media or fractured, porous media can also be modeled, but their long-term effects are equally uncertain. Commercial fracture design codes do not take thermal effects into consideration in determining the fracturing outcome. Geothermal codes for fracture stimulation design purposes that do consider thermal, as well as hydraulic effects in fracture growth, are not yet developed (DuTeaux et al., 1996).

- *Induced seismicity concerns.* In EGS tests at the Soultz site, microseismic events generated in the reservoir during stimulation and circulation were large enough to be felt on the surface. Efforts to understand how microearthquakes are produced by stimulation are ongoing, and new practices for controlling the generation of detectable microseismic events are developing. A predictive model that connects reservoir properties and operating parameters such as flow rate, volume injected, and pressure which might affect the generation of detectable microearthquakes is important to realizing the potential of EGS. Such a model has not been quantitatively established.

4.11 Remaining Needs

Although we can make an EGS reservoir with connected wells in a deep, high-temperature rock volume, there are still many areas of technology improvement needed that will help make the process more economical and less risky.

- *Reduce pressure drop without decreasing reservoir life* – We can stimulate a connected fracture system, but we have no way of stimulating specific fractures. This increases the risk that one or more high-permeability fractures will be preferentially stimulated and result in too rapid a temperature decline.
- *Prevent or repair short circuits* – Short circuiting of flow paths in the connected fracture system is a concern affecting reservoir lifetime. At Rosemanowes, Hijiori, and Ogachi, only some of the pre-existing fractures that were stimulated resulted in short circuits. We would like to be able to direct the stimulation to those fractures that are less open and away from the more conductive fractures. This would reduce the risk of short circuiting while increasing the effective heat-exchange area of the system.
- *Better understand the influence of major fractures and faults as subsurface barriers or conduits to flow* – Large-scale features such as faults and major fractures can act as either barriers or conduits to flow and can alter the planned flow paths, either to create short circuits or to move fluid out of the circulating reservoir. For instance, at Soultz, an aseismic zone, which could be either a conduit for flow or a barrier, appears in the acoustic emissions mapping. This feature seems to separate GPK4 from the rest of the wells and prevents this well from being well-connected to the circulating reservoir. While some of the methods we develop for dealing with short circuits will help us deal with large-scale faults and fractures, new methods of characterizing these features are still needed. Improving our understanding of the acoustic emissions patterns associated with these features will be one step in the process. We would also like to be able to characterize these features from the surface before we drill, so that we can take them into account during planning.
- *Characterizing rock-fluid interactions* – Despite efforts to model rock-fluid interactions, there are still major questions to be answered. Geochemical data gathered during testing has not led to any understanding of what happened during each test, let alone an ability to predict how future reservoirs will react. Several questions remain:

1) Will mineral deposition occur over time that will diminish connectivity and increase pressure drop?
2) Is mineral dissolution going to create short circuits or improve pressure drop?
3) Where will dissolution and deposition occur in the well/reservoir system if they happen?
4) Will long-term circulation result in some equilibrium being reached with the fluid and reservoir rocks?
5) Can we use rock-fluid interactions to characterize the performance of the reservoir?
6) Can we use chemical methods to stimulate or repair the reservoir?

- *Use of oil and gas stimulation methods in geothermal settings* – So far, oil and gas hydraulic fracturing has not been successful, either creating open fractures that lead to short circuiting or having no connection to the existing natural fractures. Some oilfield methods may be valuable to us, if we find ways to adapt them to our needs. Use of proppants to improve near wellbore injectivity or productivity may have very real benefits, particularly if we move to downhole production pumps. Controlled rheology fluids might be useful in diverting stimulation to the areas that most need it or in repairing short circuits.
- *Use of intermediate strain-rate stimulation* – Pressurizing the formation at a rate between explosive (micro-milliseconds) and hydro-frac (minutes-hours) methods should be explored for EGS applications, as a potential means of reducing near-wellbore impedance.

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