Lessons learned from the pioneering Hot Dry Rock project at Fenton Hill, USA

Sharad Kelkar^{1*}, Giday WoldeGabriel¹, Kenneth Rehfeldt²

*Corresponding author, Kelkar@lanl.gov, (505) 667 4639

¹Earth and Environmental Sciences Division, Los Alamos National Laboratory, Los Alamos, NM, USA.

²Formerly at Los Alamos National Laboratory, now at Navarro Research and Engineering, Oak Ridge, TN, USA.

Abstract

Interest in geothermal energy production has grown rapidly in recent years due to the increasing demand for clean, renewable, domestic energy. Recent publications have suggested that geothermal energy from Enhanced Geothermal Systems could satisfy a large portion of the energy needs in the U.S. if the technology were implemented on a large scale. Pertinent to this goal are many of the lessons learned from the pioneering Hot Dry Rock project aimed at producing usable energy from the heat of the earth, conducted from 1970 to 1995 at Fenton Hill, New Mexico, USA. During this project, the Los Alamos National Laboratory created and tested two reservoirs at depths in the range of 2.8 to 3.5 km in crystalline rock formations underlying the Fenton Hill site. Thermal energies in the range of 3 – 10 MWt were produced demonstrating the technical feasibility of the concept. Many important lessons were learned regarding the creation, engineering and operation of such subsurface systems – these lessons will prove valuable as the geothermal community moves towards the goal of realizing the immense potential of this ubiquitous renewable energy resource. The purpose of this paper is to provide a brief, easy to read overview of this pioneering project.

Keywords: EGS, HDR, Fenton Hill, stimulation, field test

1. Introduction

The abundant heat of the Earth's interior, known as geothermal energy, is manifested ubiquitously throughout the world. At a few tectonically and volcanologically active locations around the globe, such as The Geysers in California, U.S., naturally occurring hydrothermal fluids have been produced to operate commercially viable electric power plants. However, the co-occurrence of geothermal heat and ground water with sufficient formation permeability is relatively rare; much more common and abundant is the occurrence of deep geothermal formations that are hot but lack the ability to produce sufficient quantities of hot water at the surface of the Earth (Tester et al., 2006; Williams and DeAngelo, 2008). Enhanced (or Engineered) Geothermal Systems (EGS) aim to exploit such renewable energy resources by enhancing formation permeability using engineering techniques and supplying heat exchange fluids (DOE, 2009). Hot Dry Rock (HDR) reservoirs are EGS reservoirs with sufficient heat content but very low permeability and water content. Historically, the HDR concept (Potter et al., 1974) was first developed during the experimental Fenton Hill project at the Los Alamos National Laboratory (LANL); subsequently leading to the more general concept of EGS reservoirs.

Interest in EGS has grown rapidly in the recent years due to the increasing demand for clean, renewable, domestic energy resources. Geothermal resources are ubiquitous within the U.S. and

have the potential of contributing to baseload as well as peak demands for electricity. Recent publications (Williams and DeAngelo, 2008) suggest that geothermal energy could satisfy a large portion of energy demands in the U.S. if EGS technology were implemented on a large scale. While electricity has been generated from hydrothermal systems by producing naturally occurring hot water or steam for many decades, the Enhanced Geothermal Systems (EGS) have the potential of supplying at least ten times more electrical energy than all existing or likely future hydrothermal power generation systems (DOE, 2009). The Geothermal Technologies Office (GTO) of the U.S. Department of Energy (DOE) is actively funding a number of projects with the goal of realizing this renewable energy potential. These and future EGS projects stand to benefit from the lessons learned during the development of the world's first HDR demonstration project conducted at LANL. This project successfully demonstrated many aspects of the feasibility of EGS concept in low permeability basement rock. The goal of achieving power generation capacity on a commercial scale still remains a research objective for the world-wide EGS community. The utility of the data gathered by this HDR project for future work has been recognized (Robertson-Tait et al. 2000), and a project is currently under way to archive existing manuscripts from the project (Kelkar 2015a). Further, the Geothermal Code Comparison project funded by GTO has selected the Fenton Hill HDR project as the basis for challenge problems in 2015.

The purpose of this short paper is to bring the major lessons learned from the Fenton Hill HDR project to the attention of the readers who may be unfamiliar with the work, and to provide a concise summary of the work including a selection of relevant references. We believe that the readers familiar with the work will also find value in this brief, easy to read article. A detailed technical description of the project along with an extensive bibliography is provided by Brown et al. (2012), and a chronological description along with numerous references is provided by Kelkar et al. (2015b). Another good summary of the technical work accomplished by the project up to 1985 is presented by Armstead and Tester (1987). The progress of the project was documented in annual reports from 1976 through 1995, which are listed in Kelkar et al. (2015b). The world's first successful demonstration of an EGS system, the HDR project for extracting underground geothermal energy was conducted at Fenton Hill, New Mexico, USA. The HDR concept was developed in 1970 at Los Alamos National Laboratory (LANL) (Brown et al. 2012). The concept originated as an outgrowth of the Subterrene project in the late 1960s (Smith 1995). The project at Fenton Hill began in 1972. The project terminated at the end of 1995, and in 1996 the project wells were plugged and the site was decommissioned.

During the project, thermal energy production at a level of approximately 4 MWt could be sustained for 115 days of continuous fluid circulation. The project made many important contributions to the state of the art in drilling and completion technology (Carden et al. 1983), downhole tools (e.g. Dennis et al. 1985), microseismic analysis (e.g. House 1987), geochemical and tracer analysis (Robinson & Tester 1984), and numerical modeling (e.g. Zyvoloski 1983; Swanson 1995). One important development from the project was the conceptual model of a region hydraulically stimulated using water. The older models conceptualized this as a penny-shaped vertical fracture model. This was replaced by a conceptual model of the HDR reservoir as a network of preexisting joints that are dilated and sheared (e.g. Smith et al. 1985; Pine & Batchelor 1984) under high pressure stimulation. This conceptual model has had beneficial impacts on the currently used fracking technology for developing low permeability unconventional petroleum resources. Based on the data from the Fenton Hill project, Murphy et al. (1983) proposed a model with a discrete number of planar joints surrounded by existing

joints. A conceptual model has emerged (Brown 1989 and 1995) of two sets of intersecting joints, one at an inclination to the least principal stress, inflated at pressures exceeding the joint opening pressure. A model consisting of fractures failed in shear with accompanying tensile cracks that join the fractures to form planar zones has been recently proposed by Jung (2013) to explain the results of EGS projects such as Soultz and Ogachi.

The HDR research and development project was conducted in collaboration with scientists and engineers from a number of agencies inside and outside the United States. The experiment was funded primarily by the U.S. Department of Energy with additional support from the New Energy and Industrial Technology Development Organization (NEDO) representing the Government of Japan, and Kernforschungsanlage-Julich GmbH, representing the Federal Republic of Germany.

The potential for extracting usable energy from the earth's heat has attracted researchers for several centuries (Smith, 1995). Lord Kelvin in a paper read at the Royal Society of Edinburgh drew attention to natural heat as a source of power in 1852 (Thomson 1852). In 1931 Nikola Tesla in a popular article (Tesla 1931) proposed a scheme to extract geothermal heat by circulating water to the bottom of a deep shaft. The use of nuclear explosives to fragment rock on a large scale so as to create a heat exchange system was discussed in the 1960's but not attempted. But all these suggestions did not reach the stage of practical implementation, until a group of scientists at LANL proposed the use of hydraulic stimulation for this purpose in 1970. They envisioned a system of two wellbores connected to a region of stimulated high temperature rock, injecting cold fluid into one and producing hot fluid out of the other (Potter et al., 1974). The early work in the HDR project (Cramer et al. 1980) envisioned two inclined wellbores connected heat exchange surfaces created by stimulating multiple distinct zones would be needed to produce a total power in the neighborhood of 20-50 MWt for a duration of 10 years (Tester 1980). This concept calls to mind the current practice of completing long horizontal holes with multiple hydraulic stimulations in shale and other tight unconventional hydrocarbon reservoirs.

2. Overview of the Fenton Hill Project

2.1. Site selection process

In 1971, a search was initiated to identify a drilling site to test the HDR concept in the nearby Jemez volcanic field, approximately 15-30 km west of LANL (Smith, 1995). The volcanic and tectonic settings of the Jemez volcanic field provided the necessary conditions for the HDR experiment. This volcanic field has high heat flow associated with a shallow magma chamber and contains Middle to Late Pleistocene eruptive centers along the Valles caldera ring fracture, which is consistent with the occurrence of hot springs and steam vents within and outside the Valles-Toledo caldera complex, indicating the presence of abundant geothermal resources (e.g. Goff and Grigsby 1982; Heiken and Goff 1983). The discovery of high-temperature hydrothermal reservoirs within the caldera complex by an oil exploration well drilled in 1960 also confirmed the surface manifestations (Smith, 1995). Geothermal resources assessment drilling by Union Oil Company provided valuable information about the subsurface geology and structure and also indicated the existence of high-temperature hydrothermal resources within the Valles caldera complex. Thermal evolution modeling of the Valles Caldera supported the thermal measurements (Kolstad & McGetchin 1978). The detailed geological map of the Jemez volcanic field published by the USGS provided additional information about the surface geology and distribution of faults (Smith et al., 1970).

132 A site within the Santa Fe National forest to the west of the volcanic field, a few kilometers
133 from the Valles caldera margin, was selected. Considerations that factored into the decision
134 included (Brown, 2015) permitting requirements, obtaining permission from US Forest Service,
135 liability concerns, proximity to utilities, and site accessibility via paved highway, as well as heat
136 flow measurements, depth to the top of the basement rocks, and the need to be outside the system
137 of ring faults of the caldera while remaining sufficiently close to the magmatic heat source.
138 Favorable geological elements for the HDR experiment were also noted in the stratigraphic
139 succession near the proposed site where Precambrian crystalline rocks (the prime target
140 formations) are thermally insulated by thick, fine-grained Paleozoic sedimentary deposits that are
141 capped by lava and ash-flow tuffs of the Jemez Volcanic Field (Smith et al., 1970).

142 ***2.2 Site description and drilling***

143 The Fenton Hill site represents an HDR resource in proximity to the Middle Miocene- Late
144 Pleistocene Jemez volcanic field and the middle Tertiary Rio Grande Rift in north-central New
145 Mexico, USA. Specifically, the Fenton Hill site is located on the southwestern part of the Jemez
146 volcanic field a couple of kilometers to the west of the Middle Pleistocene Valles-Toledo caldera
147 complex (Fig. 1). An excellent and readable overview of the geologic history of the Valles
148 Caldera has been provided by Goff (2009), and a description of the geothermal system in the
149 area is given by Laughlin (1981). Localized episodic mafic volcanism started in the Early
150 Miocene (25 -18 Ma) along the southwestern part of the Jemez volcanic field, which coincides
151 with the western margin of the Rio Grande Rift (WoldeGabriel et al., 2013).
152

Figure 2. Location map of the Fenton Hill HDR site and simplified geological map of the Jemez volcanic field and the Espanola Basin of the Rio Grande Rift in north-central New Mexico (after Baldrige et al. 1995)

Paleozoic sedimentary deposits and Precambrian crystalline basement rocks are deeply buried beneath the Valles Caldera, but are exposed along the western part (e.g. Nacimiento Mountains) of the volcanic field a few km south and west of Fenton Hill (Fig.1). The project site was situated a few kilometers west of the Valles-Toledo caldera complex ring fractures. Extensive testing performed during the life of the Fenton Hill project later demonstrated that the experimental site was within a tectonic block of intact crystalline basement, leading to a confined reservoir with low water loss.

The initial heat-flux measurements at shallow (30 m) and intermediate (185 m) wells confirmed the existence of uniformly high heat flow over a large area to the west of the Valles caldera margin (Smith, 1983). In the spring of 1972 the GT-1 well was drilled about 3 km to the west of the Valles Caldera margin to a depth of 785 m and penetrated about 143 m of hot (104°C) crystalline basement rocks (Smith, 1983). Several types of logging tools, including temperature, density, electrical resistivity, natural gamma, caliper, acoustic velocity, and a borehole televiewer were used to document the subsurface stratigraphic, hydrological, structural, and geothermal conditions. Detailed characterization of the GT-1 well is given in Brown et al.

(2012). In 1974, the GT-2 well at Fenton Hill was drilled to the depth of 2932 m with a bottom hole temperature of 197°C. This well was sidetracked and directionally drilled to intersect the hydraulically stimulated region creating the first HDR reservoir with the wellbores EE-1 and GT-2B (Brown et al., 2012). Later in the project, in order to establish the deeper Phase II reservoir, two more wells were drilled, named EE2 and EE3. EE3 was side tracked, called EE3-A, and drilled directionally on a specific trajectory in order to create a flow-through connection with EE2. Later on EE2 was also sidetracked and redrilled, called EE2-A, because of the damage suffered by EE2 in one of the earlier stimulation experiments. The sidetracking and directional operations in granite at high temperatures were ground breaking.

2.3 Description of the reservoirs

During the life of the Fenton Hill project, LANL created and tested two HDR reservoirs in the deep crystalline rock formations at the Fenton Hill site. The first one, termed the Phase I reservoir, was created at depth intervals of 2800 to 2950 m with bottom hole temperatures in the range of 180°C to 200°C (Dash et al. 1983; Brown et al. 2012; Armstead & Tester 1987). The second reservoir, termed Phase II, was created at depths around 3500 m and bottom hole temperatures around 240°C (Duchane and Brown 2002). These are shown schematically in Figure 2. The Phase I reservoir was tested to produce thermal energies of approximately 3–5 MWt, with a thermal drawdown of 3°C to 5°C after 200 days of fluid circulation. The flow through volume of this reservoir was estimated to be ~1300–2170 m³ using tracer tests (integral mean volume, Robinson and Tester 1984).

Encouraged by the demonstration of technical feasibility, the project pursued a second reservoir, termed Phase II, which was larger, deeper, and hotter, with temperatures of up to 240°C at depths around 3.5 km (Figure 2). Details of these efforts are given in the project annual reports listed in the bibliography of Kelkar et al. (2015b) and in Brown et al. (2012). Volume estimates using tracer tests towards the end of the project ranged up to 8376 m³. The reservoir was confined—during a shut-in test in 1991, the reservoir pressure could be maintained at 15 MPa with the injection of water at a low rate of 0.25 l/s, equivalent to the rate supplied by a domestic garden hose. Testing of the Phase II reservoir at injection rates about 6.3 l/s produced sustained thermal energy of approximately 4 MWt and did not show any thermal drawdown after about 115 days of continuous fluid circulation, or 233 days of cumulative circulation, from 1993 to 1995. The water loss rate declined to ~0.46 l/s, about 7.3% of the injection rate towards the end of the test, indicating a confined stimulated region. In 1996, the wells were plugged and the site was decommissioned.

Figure 2: A schematic showing the depth of Phase I and Phase II reservoirs with the geological formations and the geothermal gradient at Fenton Hill, NM, USA. (Source: Brown et al. 2012)

2.4 Hydraulic tests

Hundreds of pumping tests were conducted during the life of the two HDR reservoirs in order to evaluate the wellbore conditions, create hydraulically stimulated regions, establish flow connections and assess the reservoir. These are discussed by Brown et al. (2012), and listed in Kelkar et al. (2015b). The annual project reports covering the duration of 1976-1995 are referenced in the bibliography of the above two citations; we don't reproduce the citations here, but summarize only the salient aspects of the most important stimulation and circulation experiments.

After a flow through connection was established in the Phase I reservoir between the wells EE-1 and GT-2B, a series of tests termed Run Segment 2 through Run Segment 5 were

conducted between 1977 and 1980 (see also Armstead & Tester 1987). Run Segment 2 was a 75 day circulation test that represented a first ever successful operation of an EGS system in the world, producing thermal power ranging up to 4.3 MWt. 25⁰C water was injected into the wellbore EE-1 at wellhead pressures in the range of ~ 6 to 8.3 MPa and flow rates in the range of 17 – 14.5 l/s. The bottom-hole temperature of the water produced from the wellbore GT-2B decreased from 175⁰C at the beginning to 85⁰C after 75 days. By the end of the test the rate of water loss had dropped below 2% of the injection rate, and the overall impedance to flow had dropped to 0.3 MPa/l/s. Run Segment 3 was conducted to confirm that the flow impedance decreased significantly at elevated backpressures. This 28 day circulation test was conducted at a high backpressure of ~9.7 MPa, injection flow rate was maintained at ~ 180 gpm while the outflow rate increased from 100 gpm to 150 gpm (Brown 1979; Brown et al. 2012) and the flow impedance decreased from ~0.22 to ~0.05 MPa/l/s. Temperature logs indicated that majority of the injected fluid exited the injection well EE-1 at a depth of ~2758m to enter the reservoir, and entered the production wellbore GT-2B via multiple paths in the depth range of 2673m to 2715m. The rapid thermal drawdown in Run Segment 3 (~ 90⁰C in 75 days) indicated the need for a larger reservoir. Cement-leakage problems had been noted during the testing in the injection well EE-1. Hence the portion of the wellbore used for the previous tests was re-cemented and hydraulic stimulation operations were conducted in deeper portions of the injection well EE-1. Temperature logging revealed that the fluid exit in the injection well had indeed shifted about 183m downhole to 2941m, but interestingly the fluid outflow zones in the production well GT-2B remained the same. Considerable microseismicity was noted in the subsequent pumping experiments (seismicity rates around 80-130 events per 200 seconds were reported in Cremer et al. 1980), along with higher flow-through impedance, indicating that the connection between the injection and production horizons had shifted to more tortuous flow paths. An analysis of flow and tracer tests in this deeper portion of the Phase I reservoir and modeling efforts has been provided by Murphy et al. (1981). Run Segment 4 was a short (~23 days) flow through-experiment including two stages of high back pressure. The flow-through impedance of the newly enlarged reservoir showed less sensitivity to elevated back pressure compared to the results of the previous Run Segment 3, indicating that the structure of the enlarged reservoir involved a more complex joint network than the reservoir during the previous testing. Tracer tests showed that the volume of the reservoir accessed was nearly an order of magnitude larger than that accessed by the previous circulation tests. The last test conducted in this Phase I reservoir was a circulation test of 281 days duration in 1980, named Run Segment 5. Injection wellhead pressure rose to ~9.9 MPa and then gradually declined to ~8.4 MPa, while the production wellhead pressure was kept ~1.3 MPa. The injection flow rate started at about 7.6 l/s at early times, decreasing to ~ 6 l/s after 150 days of pumping and finally increasing to 7 l/s after 280 days. The production rate showed an overall decline from ~6 to 5 l/s. Overall flow-through impedance stayed near 1.3 MPa/l/s. The reservoir outlet temperature increased for the first 55 days from 156⁰C to 158⁰C and gradually declined to ~149⁰C. The estimates of through-flow pore volumes at the end of this test from tracer data were approximately in the range of 1300-2170 m³ using the integral mean volume and 160-266 m³ using the modal volume (Robinson and Tester 1984).

After 1980, focus of the project shifted to the deeper, hotter Phase II reservoir. Many stimulation tests were conducted in the two wellbores EE2 and EE3 in attempts to establish flow through connections. Two major stimulation tests termed Massive Hydraulic Fracturing experiments # 2032 and #2042 were conducted respectively in the wellbores EE2 and EE3-A.

While failing to create the interwell hydraulic connections that had been hoped for, the experiments generated significant seismic datasets.

The massive hydraulic fracturing (MHF) in the well EE-2 experiment (termed Experiment 2032) was conducted by injecting 21,300 m³ of water in 61 hours (Franke et al. 1986) at an approximate depth of 3529 to 3550 m. Pumping pressures up to 48.3 MPa were used to maintain flow rates up to 132 l/s (Dreesen and Nicholson 1985). Considerable microseismic data were collected and analyzed (House 1987; Phillips et al. 1997), yielding insights into the geometry of the reservoir in the vicinity of EE2. No hydraulic connection was made with the well EE-3. Another MHF was conducted in the well EE-3 (termed Experiment 2042) by injecting 7570 m³ of water at flow rates around 53 l/s at depth around 3470 m (Franke et al. 1986; Dash et al. 1985). Again, hydraulic connection was not made with the well EE-2, however, considerable amount of microseismic data were collected and analyzed (Fehler 1989; Fehler et al. 1987). The seismic events from each of these experiments tended to cluster near the injection well on the side away from the other well (e.g. Fehler 1989) in ellipsoidal volumes with long axis on the order of 600 m or greater at an inclination of ~20° degrees to the vertical, and they did not overlap even though the inter-wellbore distance was only on the order of 200-300 m at depth. Explanations proposed for this behavior have included the effects of existing joint orientations as well as modifications to the stress field caused by prior pumping activities (e.g. 'stress cage' in Brown et al. 2012). Analysis of the seismic data helped define flow zones which could be later targeted by redrilled wellbore trajectories (Dreesen et al. 1987) to establish flow-through hydraulic connection between the wells EE2 and EE3-A, thus establishing the Phase II reservoir.

The first major circulation test of a 30 day duration, termed ICFT, was conducted in May-June of 1986 (Dash et al. 1989). A total of 37000 m³ water was injected into the well EE-3A between the depths of 3485 to 3690 m, out of which 23300 m³ was produced out of EE-2. During the first segment of the test, injection rates were around 10.6-11.4 l/s at wellhead pressures around 27 MPa. The second segment of the test was conducted at a higher injection rate around 18 l/s with wellhead pressures around 31 MPa. The production wellhead pressure was maintained fairly constant in the range of 14. – 3.4 MPa. The water loss declined to about 30% near the end of the test. Production fluid temperature at the wellhead increased during the test, reaching 200°C after 30 days. Overall flow impedance decreased from about 64 psi/gpm to 18 psi/gpm. Thermal power production increased during the test, reaching nearly 10 MWt near the end. Considerable seismicity occurred especially during the high rate injection. 684 events were located, mostly to the south of the main flow-through region, indicating reservoir growth in that direction. Two tracer tests were conducted, one in each flow rate regime. An increase in the integral mean volume from 2180 to 8440 m³ was observed.

A long term flow test (LTFT) was conducted in the Phase II reservoir during 1992-1995 by circulating water for a total of 170 days, out of which 115 days were contiguous (Duchane & Winchester, 1993; Duchane, 1995). Note that there was a long break in this test during 1993-1994 due to programmatic reasons. Cooled water at around 25°C was injected into the wellbore EE-3A at wellhead pressures in the range of 23-25 MPa and rates around 6.5-7.5 l/s. Production was out of the wellbore EE-2 at backpressures around 9.7 MPa from the depth interval in the range of 3276 to 3608 m, at temperatures in the range of 180°C at rates in the range of 5.5 to 6.3 l/s. The overall impedance at the end of the test was estimated to be 3.11 MPa/l/s (DuTeau and Brown 1993). The water loss was approximately 10% to 20% of the injected fluid, with values diminishing throughout the test. Thermal drawdown resulting from 11 months of flow testing (spread out over a period of 3 years) by re-injecting cooled water was negligible. Thermal power

produced was in the range of 3.9-4.7 MWt. There was no evidence of short circuiting in the reservoir - flow became more dispersed as indicated by tracer tests. This result is contrary to a commonly stated conceptual model of permeability enhancement and creation of runaway short-circuited flow due to thermal contraction and/or dissolution-induced opening of joints. A remarkable impedance drop occurred (Brown and DuTeau 1995) after one of the cyclic flow experiments, the production rate increasing by ~30% in less than a minute. This phenomenon could not be investigated due to funding shortfalls.

The joint opening pressure for the Phase I reservoir was ~10.3 MPa (surface value) while it had a much higher value ~31 MPa (surface value) for the deeper Phase II reservoir. Considering that the Phase II reservoir was about 200m deeper than the Phase I reservoir, the increased lithostatic gradient would contribute only ~5 MPa. The largest portion of the increase in the joint opening pressure indicated that the joints being opened in Phase II were less favorably aligned with the current in situ stress field as compared to the Phase I reservoir, assuming that the stress field itself did not undergo a rotation in orientation within the 200m depth. This conceptual picture is consistent with the higher impedance values in the Phase II reservoir.

Microseismicity accompanied many of the stimulations at Fenton Hill and included significant number of shear events (e.g. Fehler 89). Permeability enhancement likely occurred in the shear zones due to shear dilation (e.g. Lee and Cho 2002, Dempsey et al. 2015). However, the high pressure-high rate stimulations at Fenton Hill (e.g. Dash et al. 1985) were accompanied by permeability gains many orders of magnitude greater than would be expected from shear dilation alone, indicating normal joint opening due to pressure dilation. Shut-in pressure data from many experiments (e.g. Duchane 1995b) show up to 3 inflection points, indicating multiple sets of joints that were opened and dilated during high pressure pumping, and then closed as the pressure declined. This suggests a model consisting of a set of joints with normal at an angle to the minimum principal stress that are connected to the wellbores, requiring relatively high injection pressures before the formation starts accepting all the injected fluid; and other sets of intersecting joints that were aligned more favorably to the minimum principal stress.

Regarding reservoir flow-through volume, there was a range of values based on tracer tests (e.g. Rodrigues et al. 1993). Taking a nominal value of 2000m³ from these data, and a nominal porosity value of 10⁻⁴, the bulk volume of the Phase II reservoir was estimated to be on the order of 20 million m³. This value is consistent with those obtained from the hydraulic and microseismic data (Duchane and Winchester 1993).

As determined from shut-in pressure data, the largest fraction of the flow impedance was near the production well. Flow impedance at the injection well decreased quickly to small values due to hydraulic and thermal effects. It is noteworthy that the contribution to the impedance in the body of the Fenton Hill reservoir was found to be smaller than that at the production well. This has important implications for development and operating strategies because it implies that at this location reservoirs with much greater wellbore separations could be created without greatly increasing the overall reservoir flow impedance (Brown et al. 2012).

The Phase II reservoir was shut-in in 1993 due to programmatic reasons for a period of nearly 2 years following the stimulation and testing. When the testing was resumed in 1995, the reservoir recovered in a short time to nearly the same operating conditions as existed prior to shut-in (Brown et al. 2012), indicating that the open network of joints retained the effects of stimulation for that duration.

Cyclic flow tests demonstrated the ability of the HDR reservoir at Fenton Hill to complement other renewable energy sources to regulate peak load demands, and the ability to act

as an energy storage system. These tests demonstrated actual increases in the thermal output of the reservoir during cyclic production tests (Duchane, 1995). Surging experiments that involved periodic shutting-in of the production well while maintaining the injection conditions were also conducted, and show enhancement of energy production over the cycles.

During the circulation testing of the Phase II reservoir, microseismic event locations indicated that reservoir growth accompanying high water loss at elevated injection rates tended to be on the side of the injection well that was away from the production well (Brown et al. 2012). This suggests a reservoir development strategy with an injection well located between two (or more) production wells, permitting much higher flow rates that could be maintained during the tests reported here. For example, during the ICFT, an increase in the injection rate from ~ 11 l/s to 18 l/s with a power output of 10 MWt led to reservoir stimulation (evidenced by seismicity) away from the production well (Dash et al. 1989). It is tempting to speculate that had another production well existed in that portion of the reservoir, power production could have been at least doubled for the triplet (Brown et al. 2012).

2.5 Technology development

2.5.1. Drilling, Completion, and downhole logging tools

The HDR Program provided pioneering advancements in drilling (Carden et al. 1983) deep wells into hot and hard crystalline rocks with carefully controlled high-angle trajectories at inclinations up to 35° from the vertical. Development of several tools was supported for this purpose (e.g. Cremer et al. 1980) including a turbodrill for directional drilling, high-temperature hard-rock drill bits, steering tools, a drill-pipe cutoff tool using high explosives to sever the drill pipe at a downhole location (Dennis et al. 1985), high-temperature cement (Smith and Ponder 1982), and high-temperature packers (Cremer et al. 1980). Successful cementing proved to be a major challenge in completion operations. Tests were conducted to evaluate improved cement compositions (Brown et al. 1979, Smith and Ponder 1982). Several tools for subsurface interrogation had to be developed during the HDR experiment. The project developed logging tools that could function reliably under the downhole conditions of high temperatures in hard rocks (e.g. Dennis et al. 1985; Dennis 1990). These included a temperature logging tool, downhole flowmeter, multi-arm caliper, side wall sampler, detonator acoustic source, triaxial geophone sonde, borehole televiewer, a slim line spinner-temperature-pressure tool, slim line gamma ray tool, downhole-fluid sampler, four-arm caliper tool, downhole-detonator system for geophone calibration, Dewar for protecting sensitive electronic components from extreme temperatures, downhole injector, and a high-temperature gamma ray detector.

2.5.2. Microseismic events

Microseismic events attributable to reservoir stimulation and testing provided a unique opportunity for mapping the reservoir development (Albright and Hanold, 1976). Downhole and surface geophones were installed in the vicinity of the experimental site for seismic monitoring. An on-line system for recording and locating microseismic events was developed and deployed. Event locations were determined by inversion of arrival times of P (compression) and S (shear) waves that were recorded using downhole geophones, eventually acquiring a computer-automated digital-recording system with multiple channels. Downhole sensors at multiple locations were installed to permit triangulation in order to locate events more reliably - data interpretation of the microseismic events to identify locations (House 1987) resulted in cloud

shapes that indicated the stimulated region. It was conceptualized that the envelope of the seismic events formed an envelope of the stimulated region (Aki et al. 1982). Spectral analysis of the signals and fault plane solutions led to the recognition that shear failure rather than only tensile opening of fractures generated the events. These results led to an improved understanding of why multiple attempts had failed to establish hydraulic communication between the production and injection wells (Phillips et al. 1997), in turn leading to a considerable revision of the conceptual model of the Fenton Hill HDR system. Statistics of planes defined by three event locations (Fehler, 1989) was used to map the fracture planes along which the shearing events took place. Later refinements in methods for picking arrival times and planar fractures led to more refined representation of fracturing that proved extremely helpful in selecting trajectories for the production well (Dreesen et al. 1987). With recognition that the occurrence of microseismic activity indicated reservoir growth, it was possible to set limits on the operating injection pressures during the LTFT, thus curtailing reservoir growth and the accompanying water loss to low values (Duchane and Brown 2002).

2.5.3. Tracer tests

Tracer tests are valuable for 1) determining residence times and flowing volumes within the reservoir, and 2) flow dispersion within the reservoir (Robinson & Tester 1984). As demonstrated by tracer tests at Fenton Hill (Rodriguez et al. 1993), the flowing volume of the reservoir was smaller than the total stimulated volume. The flow dispersion indicated by the spread of the tracer versus time curves increased with duration of the flow at Fenton Hill, showing that short-circuiting of the flow paths was not occurring during the flow test (Duchane, 1995). Temperature-sensitive tracers were investigated to track thermal fronts (Robinson and Birdsell 1987) and to acquire valuable information regarding heat transfer surface area and temperature distribution in the reservoir (Robinson and Tester, 1990). Fracture network models were considered to model tracer results and evaluate various operational scenarios (Robinson 1988)

2.5.4. Reservoir Modeling Tools

Early in the life of the project theoretical estimates of power production from an HDR reservoir were made by Harlow and Pracht (1972). McFarland and Murphy (1976) included the effects of thermal contraction of the rock mass in estimating power production. Potential effects of thermal stress cracking were considered by Murphy (1978) and by Bazant and Wahab (1979). Demuth and Harlow (1980) developed a finite difference code to model fluid flow in a crack and heat transfer with the surrounding rock matrix. A computer code Finite Element Heat and Mass (FEHM) was developed (Zyvoloski, 1983), based on a continuum approach, to model multiphase flow with coupled fluid flow, heat transfer and rock deformation including pressure and temperature dependent rock properties on fully three-dimensional problems. The code included the facility for solving the advection-dispersion equation for modeling tracer transport. The fracture aperture was modeled as an exponential function of fluid pressure, along with the cubic law to obtain effective fracture permeability. Reservoir data were analyzed to obtain estimates of fracture apertures and their dependence on pressure. The model predicted a reservoir capable of sustaining 35 MWt for 20 years at a flow rate of ~53 l/s. This code also was used to match the hydraulic, thermal, and tracer data acquired from the 30-day initial closed-loop flow test (ICFT). The code predicted temperature drawdown of about 5°C to 25°C in 10 years. The development of FEHM has continued to the present day (Kelkar et al., 2014). Another model, based on the

code GEOCRACK [Swenson et al., 1995], which accounted explicitly for the response of joints to the in situ stress field and the pressure changes introduced by reservoir operations, was also developed in order to study the response of the reservoir to cyclic operations. This two-dimensional model sequentially coupled the flow and deformation behavior of the fractured reservoir including nonlinear dependence of permeability on joint opening. One of the important conclusions of this modeling was that controlled flow rate operations can lead to optimization of long term production.

2.6 Challenges

Drilling and completion operations in hot crystalline rocks proved to be challenging (Brown et al., 2012) and required further research and development, and many of the issues encountered in the past continue to be challenging. This was a new frontier in drilling operations at that time because of depth, the type of rocks to be drilled (i.e., hard and abrasive crystalline rocks instead of the softer sedimentary rocks in the oil field), the high temperature environment, the design requirement (based on a wrong conceptual model) of having two inclined parallel wells at close proximity and slanted ($\sim 35^\circ$) at depth (>2 km) in a predetermined direction. Hardness and abrasiveness of hot granitic formations led to severe wear of drilling tools and drillstrings and resulted in numerous twistoffs and fishing operations. Diametrical bit wear resulted in time-consuming reaming operations. High temperatures led to aggravated casing wear from tool joints. Specially designed drilling motors had to be commissioned due to the high temperatures encountered in the deeper Phase II reservoir. Cement and casing seal failure occurred several times. Problems with drilling/completion turned out to be a large fraction of the project cost (Brown et al. 2012). Even at present drilling and completion in hot crystalline rocks remains a significant fraction of the expense for an EGS project (e.g. Nathwani and Mines 2015).

Cross-well connectivity proved to be challenging to establish. The success of the HDR Program was dependent on the ability to artificially stimulate and connect a large reservoir system between injection and production wells for heat extraction and energy production. The initial strategy, developed on the basis of the understanding of underground rock mass behavior at the time, was of drilling two wells and then hydraulically fracturing the rock formation to connect them. This did not work – for example Dash et al. (1985), and Franke et al. (1986) describe the unsuccessful hydraulic stimulation attempts (termed Experiments 2032 and 2042) to create a flow connection between two of the deep wells in the Phase II reservoir. Only after redrilling one of the wells on a trajectory to intersect the flow paths deduced from microseismic data (Dreesen et al. 1987) did the project succeed in establishing flow connection. In both Phase I and Phase II, it resulted in prolonged and expensive field operations and directional redrilling before successful flow-through connections could be established between the wells. The conceptual model of hydraulically created fractures at the time was that of a vertical penny-shaped crack. Based on this model, the design of the Phase II reservoir called for creating about fourteen parallel vertical fractures intersected by two inclined boreholes, each fracture contributing about 3 to 4 MWt energy output. It was learned from field experience during the HDR Program, with the help of microseismic techniques, that a more realistic model was a network of pre-existing joints that were hydraulically stimulated. Numerous pumping experiments showed that upon injection the pressure rose very rapidly in a linear fashion indicating a very low permeability system and consistently leveled off upon reaching a threshold value that was inferred to correspond to joint opening pressure. Later flow testing revealed that the reservoir returned to almost the same operating conditions after a two year shut in

period(Brown 1995). As evidenced by the microseismic data, the joints underwent slight shear displacement during initial stimulation. Later circulation experiments at controlled pressure levels above the joint opening value in the same region proved to be seismically quite (Duchane 1995a and 1995b). It was also found that the orientation of the stimulated zone was controlled by the nature of natural fractures as well as the in situ stress field, which can vary with depth. The stimulated zone in Phase II was oriented not vertically but at approximately 45° to the vertical, implying that the expensive directional drilling employed by the project was unnecessary. In retrospect it can be said that had these more realistic conceptual models been available to the project in the 1970s, design of the system would have been very different and the outcome of the project would have been closer to the goals. It is noteworthy that surprises regarding the direction of the growth of stimulated volume were encountered in other projects such as Rosemanowes in Great Britain (e.g. Pine and Batchelor 1984; Baria and Green 1989). The European project at Soultz, benefitting from the lessons learned at Fenton Hill and Rosemanowes, utilized microseismic data to design wellbore trajectories (Baria et al. 2005). At Soultz, the size of the stimulation treatments needed for establishing good connectivity turned out to be much greater than originally anticipated by the project. After much costly and time consuming work, it was discovered from the field experiments that a successful operational strategy would consist of drilling the first well to the target while drilling the second well partially into the tight crystalline basement rock, placing geophones in the second well and hydraulically stimulating the first well while monitoring the generated microseismic activity to locate the stimulated zone, and then targeting this zone with the subsequent wells.

3. Subsequent USA and International projects

The HDR concept generated worldwide interest – in the late 1970's there were active field projects in Germany (Tenzer 2001), UK (e.g. Batchelor 1982) and France (Cornet 1987). The interest in EGS has grown overtime with many countries around the world undertaking research and development to realize this important source of clean energy. In a recently published review article, Breede et al. (2013) list 31 EGS projects since 1970, of which 22 are currently active in various stages of development. As the summaries by Tester et al. (2006) and Breede et al. (2013) suggest, the number of EGS sites worldwide is quite small considering the vast potential of EGS geothermal energy. Most of the projects to date have been research and development efforts to understand various aspects of the problem. Of the 22 active sites presented by Breede et al. (2013), 14 are producing electricity and only 6 are considered commercial. For a renewable resource with such great potential to provide long term base load power, why has the development been so difficult and slow? A big part of the answer to this question is that each site to date has presented a unique geologic, hydrologic and thermal environment that has required considerable effort to understand and address. While subsurface investigations are commonplace considering the enormous experience of groundwater supply, fossil energy and mining endeavors, the geothermal efforts are often unique and outside the experience of anything that has come before it.

Despite the relatively limited effort worldwide (compared with fossil energy for example), a number of similarities have been identified across the spectrum of EGS development. First, as summarized in Section 3, it is best to drill a single well, hydraulically fracture the formation, monitor the fracturing via microseismic methods, then drill subsequent wells to intersect the stimulated fracture network. Additionally (Tester et al., 2006; Breede et al., 2013) most of the stimulation occurs along naturally occurring planes of weakness that are opened by shear

processes rather than tension fracturing. As a result, it is common for induced seismicity to be of concern at many EGS sites both in the United States and around the world (Breede et al., 2013). Two fundamental unknowns at all the EGS sites are the ambient planes of weakness (and their properties) and the ambient state of stress in the formations. Together, these two unknowns account for much of the risk associated with EGS development. As Tester et al. (2006) point out, many of the challenges hindering the commercial utilization of EGS can be overcome with substantial government investment.

In 2014, the United States Department of Energy Geothermal Technologies Office began the process to develop a Field Observatory for Research in Geothermal Energy (FORGE). The FORGE investment, if it comes to full fruition, could potentially provide a good portion of the research and development necessary to move EGS further toward commercial utilization. In addition, there are current efforts in the U.S. Government to coordinate investment across different agencies to maximize the benefit of subsurface research, termed SubTER (DOE, 2015). It is recognized that progress in wellbore technology, permeability manipulation, state of stress and induced seismicity, and subsurface signals analysis and detection are common to the goals of projects in renewable energy (including geothermal energy), fossil energy, nuclear energy, environmental management, and basic geoscience. These efforts will help to maximize the returns on investment in geothermal energy development.

Despite the first HDR demonstration experiment at Fenton Hill about four decades ago, current EGS projects around the world have not delivered the abundant renewable energy that the Fenton Hill HDR experimental results promised because of many formidable challenges. Even with great advances in engineering and technology applications in exploration, drilling, and completion methods, the geothermal industry is lagging behind compared with other renewable energy ventures. Of course, EGS is site specific and the experience from one site cannot be easily applied at other locations because of different geologic settings and rock types. A recent assessment of the past, current, and future EGS projects suggested that more needs to be done to successfully harness the vast energy resource (Ziagos et al., 2013).

Several major factors, including technical, economic/financial, and public perception appear to be responsible for the lack of progress to exploit the vast energy resources in the accessible upper crust of the earth. Technical challenges are numerous requiring support for RD&D. Acquiring adequate financial support remains challenging, resulting in large part from uncertainties related to lifetimes and recovery potentials of the EGS projects (DOE, 2013). Moreover, environmental issues related to induced seismic tremors generated during EGS operations exacerbate the two major problems described above. Induced seismic events (Zang et al. 2014) have negatively impacted public interest in the growth of EGS industry and in some cases projects were suspended or totally abandoned (Breede et al., 2013). The EGS industry has a bright future awaiting technological developments, because there is a vast geothermal energy resource that must be harnessed in the interest of humanity using environmentally sensible methods.

4. Conclusions - Lessons Learned

We have presented a brief summary of the Fenton Hill HDR experiment that was conducted from 1970 to 1995. This project took the concept of extracting heat from the earth from an idea to a field-scale demonstration. The major lessons learned from this project, presented below, remain relevant today as the geothermal industry, with DOE support, moves

forward towards the goal of developing commercial quantities of electricity from the renewable, ubiquitous EGS resources.

- Hot Dry Rock concept was proved via field demonstration: it is possible to extract subterranean thermal energy by establishing a HDR reservoir in hot, low-permeability, low-water content, crystalline basement rock. The Fenton Hill project was able to achieve fluid production rates on the order of 5-7 l/s between a pair of wellbores (Duchane and Brown 2002). The achievement of commercial levels (e.g. 80 kg/s, Tester et al. 2006) of EGS fluid production has remained a challenge for the geothermal community.
- Stimulation: Geothermal reservoirs in crystalline rocks can be stimulated by hydraulic treatments.
- Microseismic event locations indicate an envelope around the stimulated region: microseismic event locations can be used as indicators of the location and envelope of the reservoir volume stimulated by hydraulic treatments.
- A network of preexisting joints that are dilated under high pressure stimulation forms a much better conceptual model of the HDR reservoir, than a penny-shaped vertical fracture model that was based on previous beliefs.
- Staged Development of HDR project : Drilling one well first, stimulating and monitoring microseismic events, then drilling the subsequent wells is the systematic process that should be used to establish HDR reservoirs:
- Deep crystalline basement rocks marginal to volcanic centers away from active fault systems are good candidates for HDR systems: such formations have high heat content, low matrix permeability, and existing natural joints tend to be closed away from active fault systems minimizing natural water convection and provide good containment of operating fluid.
- HDR reservoirs persist through periods of inactivity: The effects of reservoir stimulation persist over time, even after extended periods with fluid pressures approaching ambient values.
- HDR systems can provide baseload and peaking power production: HDR resources can complement other renewable energy sources to regulate peak load demands, and the ability to act as an energy storage system.
- Flow impedance was greatest at the production well for the Fenton Hill project: This has important implications for development and operating strategies. If reservoirs with much greater wellbore separations could be created this would not greatly increase the overall reservoir flow impedance.
- Thermal power can be produced over extended periods from HDR reservoirs: eleven months of flow testing produced thermal power of 3.9 MWt with negligible thermal drawdown. There was no evidence of short circuiting in the reservoir.

5. Acknowledgements

This work was supported in part by the U.S. Department of Energy- Geothermal Technologies Program Office under contract No. DE-AC52-06NA25396. The authors gratefully acknowledge many useful and knowledgeable discussions with Don Brown and Dave Duchane, who are retired members of the HDR staff. We acknowledge Don Brown further for a critical review of the manuscript.

References

- Aki, K., M. Fehler, R. Aamodt, J. Albright, R. Potter, C. Pearson and J. Tester, 1982. Interpretation of seismic data from hydraulic fracturing experiments at the Fenton Hill, New Mexico, Hot Dry Rock Geothermal Site. *J. Geophys. Res.* 87, 936-944, 1982.
- Albright, J., and R. Hanold, 1976. Seismic mapping of hydraulic fractures made in basement rocks. *Proceedings of the Energy Research and Development Administration-ERDA-Symposium on Enhanced Oil and Gas Recovery.*
- Baldrige, W. S., Keller, G. R., Haak, V., Wendlandt, E., Jiracek, G. R., and Olsen, K. H., 1995. The Rio Grande Rift. In Olsen, K. H., ed., *Continental Rifts: Evolution, Structure, Tectonics: Amsterdam, Elsevier*, 233-275.
- Baria, R. and A. S. P. Green, 1989. Microseismics: A Key to Understanding Reservoir Growth. In *Hot Dry Rock Geothermal Energy. Proc. Camborne School of Mines International Hot Dry Rock Conference*, Ed. Roy Baria, Camborne School of Mines Redruth, Robertson Scientific Publications, London, 363-377.
- Baria, R., S. Michelet, J. Baumgartner, B. Dyer, J. Nicholls, T. Hettkamp, D. Teza, N. Soma, H., Asanuma, J. Garnish, T. Megel, T. Kohl, and L. Kueperkoch, 2005. A 5000 m Deep Reservoir Development at the European HDR Site at Soultz. *Proc. 30th Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford, Calif., Jan. 31–Feb. 2, Paper No. SGP-TR-176.
- Batchelor, A.S., 1982. The stimulation of a Hot Dry Rock geothermal reservoir in the Cornubian Granite, England. *Proceedings of 8th Workshop on Geothermal Reservoir Engineering*, 14-16 December, Stanford, CA, USA.
- Bazant, A.A., and Wahab, A.A., 1979. Instability and spacing of cooling or shrinkage cracks. *J. of the Eng. Mech. Division*, Vol.105, No. 5, 873-889.
- Breede K., Dzebisashvili K., Xiaolei L., and Falcone G., 2013. A systematic review of enhanced (or engineered) geothermal systems: past, present and future. *Geothermal Energy*, 1, 1-27.
- Brown, D.W., 1979. Results of Expt.186, the high back-pressure flow experiment. Office Memorandum G-3/79/#4, March 30, 1979, Los Alamos Scientific Laboratory, Los Alamos, New Mexico, USA.
- Brown, M. C., R. B. Duffield, C. L. B. Siciliano, and M. C. Smith. 1979. Hot Dry Rock Geothermal Energy Development Program, Annual Report, Fiscal Year 1978. LA-7807-HDR, Los Alamos Scientific Laboratory, Los Alamos, New Mexico, 87545, USA.
- Brown, D.W., 1989. The potential for large errors in the inferred minimum earth stress when using incomplete hydraulic fracturing results. *Int. J. Rock Mech. Min. Sci. & Geomech. Abstr.* Vol 26, NO. 6 573-577.
- Brown, D.W., 1995. 1995 Verification flow testing of the HDR reservoir at Fenton Hill, New Mexico. *Geothermal Resources Council Transactions*, Davis, CA
- Brown, D. W., Duchane D. V., Heiken G., and Hriscu V. T., 2012. *Mining the Earth's Heat: Hot Dry Rock Geothermal Energy*, Springer.
- Brown D.W., (2015). Personal communication.
- Carden R.S., Nicholson R.W., Roland A., and Rowley J.C., 1983. Unique aspect of drilling and completing Hot-Dry-Rock geothermal wells. *IADC/SPE Drilling Conference*, Feb 20-23, New Orleans, Louisiana, USA.

668 Cornet, F.H., 1987. Results from Le Mayet de Montagne Project. *Geothermics*, Vol. 16,
 669 No. 4, 355-374.

670 Cremer, G. M., R. B. Duffield, M. C. Smith, and M. G. Wilson, 1980. Hot Dry Rock
 671 Geothermal Energy Development Program, Annual Report, Fiscal Year 1979. LA-8280-HDR,
 672 Los Alamos National Laboratory, Los Alamos, NM, USA.

673 Dash, Z.V., Dreesen D.S., Walter, F., and House, L., 1985. The Massive Hydraulic
 674 Fracture of Fenton Hill HDR Well EE-3. International Symposium on Geothermal Energy,
 675 Geothermal Resources Council, August 26-30, Kailua-Kona, Hawaii, USA.

676 Dash, Z.V., Aguilar, R.G., Dennis B.R., and LANL Hot Dry Rock Program Staff, 1989.
 677 ICFT: An initial Closed-Loop Flow Test of the Fenton Hill Phase II HDR Reservoir. Los Alamos
 678 National Laboratory report LA-11498-HDR, Los Alamos, NM, USA.

679 Dempsey D, Kelkar S, Hickman S, Davatzes N, Moos D, 2015. Modeling Shear
 680 Stimulation of the EGS Well Desert Peak 27-15 Using a Coupled Thermal-Hydrological-
 681 Mechanical Simulator. In preparation for International Journal of Rock Mechanics and Mining
 682 Sciences, 78 190-206. <http://dx.doi.org/10.1016/j.ijrmms.2015.06.003>

683 Dennis, B.R., Koczan, S. P., and Stephani, E. L., 1985. High Temperature borehole
 684 instrumentation. Los Alamos National Laboratory report LA-10558-HDR, Los Alamos, NM,
 685 USA.

686 Dennis B.R., 1990. High-temperature borehole instrumentation developed for the DOE
 687 Hot Dry Rock Geothermal Energy Program. *Geotherm. Resour. Coun. Bull* 19 (3): 71-81.

688 DOE (U.S. Department of Energy). 2009. "Geothermal Technologies Program. Multi-
 689 Year Research, Development and Demonstration Plan, 2009–2015 with program activities to
 690 2025," U.S. Department of Energy, Energy Efficiency & Renewable Energy Office,
 691 <http://www.eere.energy.gov/geothermal/plans.html>

692 DOE (U.S. Department of Energy). 2013. "Enhanced Geothermal Systems", JASON
 693 report, MITRE Corporation, <http://www1.eere.energy.gov/geothermal/pdfs/jason.final.pdf>

694 DOE (U.S. Department of Energy). 2015. "Energy Department Subsurface Crosscut",
 695 SubTER-fact-sheet-10-16, [http://energy.gov/sites/prod/files/2014/10/f18/SubTER-fact-sheet-10-](http://energy.gov/sites/prod/files/2014/10/f18/SubTER-fact-sheet-10-16.pdf)
 696 [16.pdf](http://energy.gov/sites/prod/files/2014/10/f18/SubTER-fact-sheet-10-16.pdf)

697 Dreesen, D. S., and R. W. Nicholson. 1985. Well completion and operations for MHF of
 698 Fenton Hill HDR well EE2. Geothermal Resources Council Annual Meeting, Kailua-Kona,
 699 Hawaii, August 26-30.

700 Dreesen, D.S., Malzahn M., Fehler M.C., and Dash Z.V. 1987. Identification of MHF
 701 (Massive Hydraulic Fracture) Fracture Planes and Flow Paths by Correlating Well Log Data with
 702 Patterns in Locations of Induced Seismicity. *Transactions Geotherm. Res. Coun.* 11, 1987.

703 Duchane, D.V, and Brown, D.W., 2002. Hot Dry Rock (HDR) geothermal energy
 704 research and development at Fenton Hill, New Mexico. *Geothermal Heat Center Bulletin*.

705 Duchane, D.V. 1995a. Hot Dry Rock Geothermal Development Program, Progress
 706 Report, Fiscal Year 1993. Los Alamos National Laboratory Report LA-12903-PR, Los Alamos,
 707 New Mexico, 87545, USA.

708 Duchane, D.V., 1995b. Heat mining to extract Hot Dry Rock geothermal energy:
 709 technical & scientific progress. In *Geothermal Energy R&D Program*, Federal Geothermal
 710 Energy Program, U.S. Department of Energy

711 Duchane, D.V., and Winchester W.W., 1993. Hot Dry Rock Energy, Annual Report,
 712 Fiscal Year 1992. Los Alamos National Laboratory, Los Alamos, New Mexico, 87545, USA.

DuTeau, R., and Brown D., 1993. "HDR Reservoir Flow Impedance and Potential for
 Impedance Reduction," Eighteenth Workshop on Geothermal Reservoir Engineering, Stanford
 University, Stanford, California, January 26-28.

Franke, P.R., Brown D.W., Smith M.C., and Mathews K.L., 1986. Hot Dry Rock
 Geothermal Energy Development Program Annual Report Fiscal Year 1984. LA-10661-HDR,
 Los Alamos National Laboratory, Los Alamos, NM, USA.

Fehler, M., House, L., and Kaieda H., 1987. Determining Planes along Which
 Earthquakes Occur: Method and Application to Earthquakes Accompanying Hydraulic
 Fracturing. JGR, Vol. 92, No. B9, 9407-9414.

Fehler, M. C., 1989. Stress control of seismicity patterns observed during hydraulic
 fracturing experiments at the Fenton Hill Hot Dry Rock geothermal energy site, New Mexico.
 International Journal of Rock Mechanics and Mining Sciences & Geomechanics Abstracts, Vol.
 26, Iss. 3-4, July, 211-219.

Goff, F., 2009. Valles Caldera – A Geologic History. University of New Mexico Press,
 ISBN 978-0-8263-4590-5.

Goff, F., and Grigsby, C.C., 1982. Valles Caldera geothermal systems, New Mexico,
 U.S.A. Journal of Hydrology, Vol. 56, Iss. 1-2, March, 119-136.

Harlow, F. H., and W. E. Pracht. 1972. A Theoretical Study of Geothermal Energy
 Extraction. Journal of Geophysical Research, vol. 77, 7038-7048.

Heiken G. and Goff F., 1983. Hot Dry Rock Geothermal Energy in the Jemez Volcanic
 Field, New Mexico. J. of Volcanology and Geothermal Research, 15, 223-246.

House, L., 1987. Locating Microearthquakes Induced by Hydraulic Fracturing in
 Crystalline Rock. Geophys. Res. Letters, Vol. 14, No. 9, September, 919-921.

Jung R., 2013. EGS-Goodbye or Back to the Future. ISRM International Conference for
 Effective and Sustainable hydraulic Fracturing, 20-22 May, Brisbane, Australia.
<https://www.onepetro.org/conference-paper/ISRM-ICHF-2013-022>

Kelkar, S., 2015a. Archive of Fenton Hill Data, presented at the Geothermal
 Technologies Office Peer Review, 12 May 2015, Westminster, CO, USA.

Kelkar, S., Woldegabriel G., and Rehfeldt K., 2015b. Hot Dry Rock Geothermal Energy
 Development at Los Alamos National Laboratory: 1970-1995 Final Report. Los Alamos National
 Laboratory Report LA-UR-15-22668, Los Alamos, New Mexico.

Kelkar, S., K. Lewis, S. Karra, G. Zyvoloski, S. Rapaka, H. Viswanathan, P. K. Mishra,
 S. Chu, D. Coblenz, and R. Pawar, 2014. A simulator for modeling coupled thermo-hydro-
 mechanical processes in subsurface geological media. International Journal of Rock Mechanics
 and Mining Sciences 70: 569-580.

Kolstad, C.D. and McGetchin, T.R., 1978. Thermal evolution models for the Valles
 caldera with reference to a hot-dry-rock geothermal experiment. J. Volcanol. Geotherm. Res., v.
 3, 197-218.

Laughlin, A.W., 1981. The geothermal system of the Jemez Mountains, New Mexico and
 its exploration. In: Geothermal systems: Principles and Case Histories (L. Ryback and L.J.P.
 Muffler, eds.), John Wiley and Sons Ltd., 95-320.

Lee, H. S., and T. F. Cho. 2002. Hydraulic Characteristics of Rough Fractures in Linear
 Flow under Normal and Shear Load. Rock Mech. Rock Engng. 35: 299-318.

McFarland, R.D. and Murphy, H.D, 1976. Extracting energy from hydraulically-fractured
 geothermal reservoirs. 11th Intersociety Energy Conversion Engineering Conference, State Line,
 NV, USA, September 12-17.

Murphy, H.D., 1978. Thermal stress cracking and the enhancement of heat extraction from fractured geothermal reservoirs. Los Alamos Scientific Laboratory Report LA-7235-MS, Los Alamos, NM, USA.

Murphy, H.D., Tester, J.W., Grigsby, C.O., and Potter, R.M., 1981. Energy extraction from fractured geothermal reservoirs in low-permeability crystalline rock. *J. Geophys. Res.*, v. 86, 7145-7158.

Murphy, H.D., Keppler, H., and Dash, Z.V., 1983. Does hydraulic-fracturing theory work in jointed rock masses?, *Transactions, Geothermal Resources Council Annual Meeting*, October 13-27, Portland, OR, USA.

Nathwani, J. and Mines, G., 2015. Cost Contributors to Geothermal Power Generation. *Proceeding World Geothermal Congress*, 19-25 April, Melbourne, Australia.

Phillips, S. ., House L.S., and Fehler M.C.m, 1997. Detailed joint structure in a geothermal reservoir from studies of induced microearthquake clusters. *J. Geophys. Res.*, vol. 102, No. B6, 11745-11763, June 10, 1997.

Pine, R.J., and Batchelor A.S., 1984. Downward Migration of Shearing in Jointed Rock during Hydraulic Injections. *Int. J. Rock Mech. Min. Sci. & Geomech. Abstr.* Vol. 21, No. 5, 249-263.

Potter, R.M., E S. Robison, and M.C. Smith. 1974. Method of extracting heat from dry geothermal reservoirs. United States Patent, 3786858, Filed Mar. 27, 1972, Appl. No. 238,435.

Robertson-Tait, A., Klein, C.W, and McLarty, L., 2000. Utility of data gathered from the Fenton Hill project for the development of Enhanced Geothermal Systems. *Geothermal Resources Council Transactions*, v., 24, p. 161-167.

Robinson, B.A., and Tester, J.W., 1984. Dispersed Fluid Flow in Fractured Reservoirs: An Analysis of Tracer-Determined Residence Time Distributions. *JGR*, Vol. 89, No. B12, 10374-10384, November 10.

Robinson, B.A., and Birdsell, S.A., 1987. Tracking thermal fronts with temperature-sensitive chemically reactive tracers. *Fifth Geothermal Program review*, Washington D.C., April 14-15.

Robinson, B.A., 1989. A discrete fracture model for a hot dry rock geothermal reservoir. *International HDR Geothermal Energy Conference*, Camborne, U.K. June 27-30.

Robinson, B. A., and Tester J. W., 1990. Kinetics of alkaline-hydrolysis of organic esters and amides in neutrally-buffered solution, *International Journal of Chemical Kinetics*, 22(5), 431-448.

Rodrigues, N.E.V., Robinson B.A., and Counce, D., 1993. Tracer experiment results during the long-term flow test of the Fenton Hill reservoir. 18th Annual workshop on Geothermal Reservoir Engineering, Stanford University, 23-26 January, Stanford, CA, USA.

Smith, R.L., R.A. Bailey, and C.S. Ross. 1970. Geologic Map of the Jemez Mountains, New Mexico. U.S. Geological Survey Map I-571, Scale 1:125,000, 1 sheet.

Smith, M. C., G. M. Ponder, and LANL Hot Dry Rock Program Staff, 1982. Hot-Dry-Rock Geothermal-Energy Development Program, Annual Report, Fiscal Year 1981," LA-9287-HDR, Los Alamos National Laboratory, Los Alamos, New Mexico, 87545, USA.

Smith, M.C., 1983. A History of Hot Dry Rock Geothermal Energy Systems. *Journal of Volcanology and Geothermal Research* vol. 15, 1-15.

Smith, M. C., G. J. Nunz, and M. G. Wilson. 1985. "Hot Dry Rock Geothermal Energy Development Program, Annual Report, Fiscal Year 1983," LA-10347-HDR, Los Alamos National Laboratory, Los Alamos, New Mexico, 87545, USA.

Smith, M., 1995. The furnace in the basement: Part 1, The early days of the Hot Dry Rock Geothermal Energy Program, 1970—1973. Los Alamos National Laboratory Report LA-12809, Los Alamos, NM, USA.

Swenson, D., DuTeauR., and SpreckerT., 1995. Modeling flow in a jointed geothermal reservoir. Proc. World Geothermal Congress.

Tenzer, H., 2001. Development of hot dry rock technology. Bulletin Geo-Heat Center, 32 (4): 14-22

Tesla, N., 1931. Our Future Motive Power. In Everyday Science and Mechanics, December 1931, edited by Hugo Gernsback.

Tester, J., B. Anderson, A. Batchelor, D. Blackwell, R. DiPippo, E. Drake, J. Garnish, B. Livesay, M. Moore, and K. Nichols, 2006. The Future of Geothermal Energy. Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century. Massachusetts Institute of Technology, 209.

Williams, C., and J. DeAngelo, 2008. Mapping geothermal potential in the western United States, Geothermal Resources Council Transactions, 32, 181.

Thomson, W., (1852). On the Sources of energy in nature Available to Man for the Production of Mechanical Effect. In Science, Vol 2, No. 67, October 8 (1881), 475-478. <http://www.jstor.org/stable/2900786>

WoldeGabriel, G., KoningD. J., BroxtonD., and WarrenR. G., 2013. Chronology of volcanism, tectonics, and sedimentation near the western boundary fault of the Española Basin, Rio Grande rift, New Mexico. Geological Society of America Special Papers, 494, 221-238.

Ziagos, J., PhillipsB. R., BoydL., JelacicA., StillmanG., and HassE., 2013. A technology roadmap for strategic development of enhanced geothermal systems. Proceedings of the 38th Workshop on Geothermal Reservoir Engineering, Stanford, CA.

Zyvoloski, G., 1983. Finite element methods for geothermal reservoir simulation. International Journal for Numerical and Analytical Methods in Geomechanics, 7(1), 75-86.

Zang, A., Oye V., Jousset P., Deichmann N., Gritto R., McGarr A., Majer E., and Bruhn D., 2014. Analysis of induced seismicity in geothermal reservoirs – An overview, Geothermics, 6-21