HOT DRY ROCK TECHNOLOGY

Chairperson: George P. Tennyson, Jr.
Albuquerque Field Office
U.S. Department of Energy

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HOT DRY ROCK - SUMMARY

George P. Tennyson, Jr., Chairperson
DOE Albuquerque Field Office

Hot Dry Rock adds a new flexibility to the utilization of geothermal energy. Almost always the approach has been to limit that utilization to places where there is a natural source of water associated with a source of heat. Actually, the result was that steam was mined. Clearly there are much larger heat resources available which lack natural water to transport that energy to the surface. Also, as is found in hydrothermal fields being mined for steam, the water supply finally gets used up. There is a strong motive in the existing capital investment to revitalize those resources.

Techniques for introducing, recovering and utilizing the water necessary to recover the heat from below the surface of the earth is the subject of this session. Implicit in that utilization is the ability to forecast with reasonable accuracy the busbar cost of that energy to the utility industry. The added element of supplying the water introduces costs which must be recovered while still supplying energy which is competitive. Hot Dry Rock technology can supply energy. That has been proved long since. The basic barrier to its use by the utility industry has been and remains proof to the financial interests that the long term cost is competitive enough to warrant investment in a technology that is new to utility on-grid operations.

As the opening speaker for this session states, the test that is underway will "simulate the operations of a commercial facility in some ways, but it will not show that energy from HDR can be produced at a variety of locations with different geological settings." Further, the Fenton Hill system is a research facility not designed for commercial production purposes, but it can give indications of how the system must be changed to provide economic HDR operations.

And so it is that we must look beyond the long term flow test, at the opportunities and challenges. Proving that the huge HDR resources can be accessed on a worldwide scale must involve the construction of additional sites, preferably to the specifications of the non-Federal geothermal community. These facilities will have to be engineered to produce and market energy at competitive prices.

At the same time, we must not rest on our technological laurels, though they be many. Design and operational techniques have been conceived which could lead to improved economics and operations for HDR. These must be pursued and where merit is found, vigorously pursued.

Accelerated research and development ought to include revolutionary drilling techniques, reservoir interrogation, and system modelling to assure the competitiveness and geographical diversity of applications of HDR. Much of this work will be applicable to the geothermal industry in general. More advanced research ought to include such innovations as the utilization of other operating fluids. Supercritical carbon dioxide and the ammonia/water (Kalina) cycle have been mentioned.

But even as the near and more distant outlook is examined, today's work was reported in the HDR session.

The start-up operations for the current test series at the Fenton Hill HDR Pilot Plant were described. The surface plant is complete and initial operations have begun. While some minor modifications to the system have been required, nothing of consequence has been found to impede operations. Reliability, together with the flexibility and control required for a research system were shown in the system design, and demonstrated by the preliminary results of the plant operations and equipment performance.

Fundamental to the overall success of the HDR energy resource utilization is the ability to optimize the pressure/flow impedance/time relationships as the reservoir is worked. Significant new insights are still being developed out of the data which will substantially affect the operational techniques applied to new systems. However, again, these will have to be proved to be general and not solely specific to the Fenton Hill site. Nevertheless, high efficiency use of the reservoir without unintended reservoir growth or water retention or life degradation depends on detailed understanding of the hydraulic behavior of this reservoir and the degree to which that understanding applies to HDR reservoirs in general.

In summary, it would seem that the nation and its utility system has a vital, practicable, and economical source of energy on the brink of availability. The research and development needed to assure the optimization of that resource application continues.

HDR Opportunities and Challenges Beyond the Long-Term Flow Test

by

David Duchane
Earth and Environmental Sciences Division
Los Alamos National Laboratory

Abstract

The long term flow test (LTFT) of the world's largest, deepest, and hottest hot dry rock (HDR) reservoir currently underway at Fenton Hill, NM, is expected to demonstrate that thermal energy can be mined from hot rock within the earth on a sustainable basis with minimal water consumption. This test will simulate the operations of a commercial facility in some ways, but it will not show that energy from HDR can be produced at a variety of locations with different geological settings. Since the Fenton Hill system was designed as a research facility rather than strictly for production purposes, it will also not demonstrate economic viability, although it may well give indications of system modifications needed for economic HDR operations.

A second production site must be constructed, ideally under the direction of the private geothermal community, to begin the process of proving that the vast HDR resources can be accessed on a worldwide scale. This facility should be designed and engineered to produce and market energy at competitive prices. At the same time, a wide variety of techniques to advance the state-of-the-art of HDR technology must be pursued to develop this infant technology rapidly to its maximum potential. A number of design and operational techniques have been conceived which may lead to improved economics in HDR systems. After careful technical and economic scrutiny, those showing merit should be vigorously pursued. Finally, research and development work in areas such as reservoir interrogation, and system modeling must be accelerated to increase the competitiveness and geographical applications of HDR and the geothermal industry in general.

This paper addresses the above issues in detail and outlines possible paths to future prosperity for the commercial geothermal industry.

Introduction

The development of the technology to extract the geothermal energy found almost everywhere beneath the earth in the form of hot dry rock (HDR) has been underway for almost two decades. A technique for mining the heat from HDR was scientifically demonstrated at the Los Alamos National Laboratory in the late 1970's (Dash, Murphy and Cremer 1981). Subsequent work, both in the United States and in a number of other countries around the world, has focused on expanding the scientific understanding of the heat mining process, while at the same time engineering HDR systems to demonstrate that the technology can produce energy at economically attractive costs.

The HDR heat mining process, as developed at Los Alamos, entails first drilling a well to reach rock which is sufficiently hot to be useful. Water is then pumped down the well under pressures high enough to open up natural joints in the rock and create a man-made reservoir consisting of a relatively small amount of water dispersed in a large volume of rock. One or more additional wells are subsequently drilled to intercept the reservoir at some distance from the first.

The system is operated by circulating pressurized water down one well (the injection well), then forcing it across the reservoir and up the other wells (the production wells). As the water flows across the hot reservoir, it becomes heated by contact with the hot rock. At the surface, this thermal energy is extracted by a heat exchanger and the water is recirculated to repeat the process. The same water thus flows repeatedly around the system in a closed-loop to mine the heat from the depths of the earth.

The world's largest, deepest, and hottest HDR reservoir was created at Fenton Hill, NM, over a period of 6 years between 1980 and 1986 (Tester, Brown, and Potter 1989). In the process of doing this, numerous technical challenges related to drilling, logging, and reservoir stimulation were encountered and overcome. A 30-day flow test was conducted in 1986 using rented pumping equipment and a temporary installation at the surface. Results of that test were extremely promising (Dash 1989), as shown in Table 1.

Table 1. 30 Day Flow Test: Final Operating Data

Injection	
Pressure	31 MPa (4500 psi)
Temperature	18°C (64°F)
Flow	285 gpm
Production	
Pressure	6.9 MPa (1000 psi)
Temperature	200°C (390°F)
Flow	220 gpm
Thermal Power Production	10 MW
Water Loss (based on injection flow)	23%

During 1987-1988, modifications were made to the underground system to improve its structural integrity. Figure 1 shows a view of this system as it exists today.

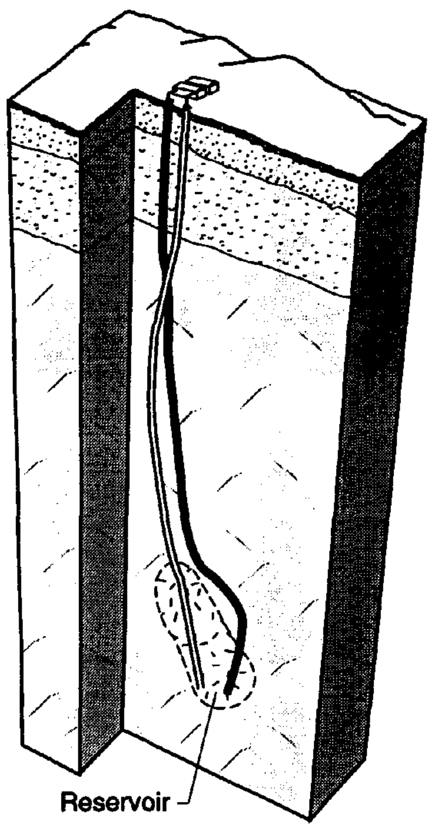

Figure 1. The Phase II HDR reservoir. The reservoir is ellipsoidal in shape with gross dimensions of approximately 200x1000x1000 meters. It is centered about 3.6 kilometers below the surface.

In the past, the course of reservoir test programs was often determined more by difficulties in pumping or in fluid handling at the surface than by reservoir performance or the best-laid reservoir assessment program. In order to overcome this problem, a permanent surface plant was designed and constructed at the Fenton Hill HDR site between 1988 and 1991 (Ponden 1991). This facility has been built to power plant standards and is highly automated. With construction of the surface plant now complete, the entire system is ready for extended testing.

A long-term flow test (LTFT) of the Fenton Hill reservoir is now underway. The duration of the LTFT is still not clear as this paper is being written. Depending upon imminent funding decisions, the test could run for as little as 90 days during Fiscal Year 1992, or could extend for a continuous period of 1 or more years. The LTFT has been designed to answer important questions regarding the ability of the Fenton Hill reservoir to deliver energy in useful quantities over an extended time period. Conduct of the LTFT over a time period long enough to produce credible thermal lifetime estimates and thorough documentation of the test results are the next essential steps in the development of HDR in the United States.

This paper begins with a presumption that a satisfactory LTFT will be completed and that the results will show that the effort to wrest geothermal energy from HDR is still worth pursuing. From that starting point, a number of potential future technology advancements which could make HDR the geothermal energy source of the future are suggested.

HDR: The Geothermal Energy of Tomorrow

The fact that a vast amount of energy is stored underground in the form of HDR is unquestioned. Calculations based on reasonable assumptions have indicated that millions of quads of geothermal energy exist in HDR under the surface of the United States at depths reachable with today's technology - enough to supply all the energy needs of the world for thousands of years (Armstead and Tester 1987). While HDR is ubiquitous, the depth as which usefully hot rock can be reached is highly variable and is related to both local and regional geological conditions. Figure 2, a geothermal gradient map of the United States, shows that in the west HDR lies relatively near the surface in many places but in the east the resource is almost uniformly found at much greater depths.

HDR can also be an extremely clean energy source. When an HDR facility is operated in a closed-loop mode as described above, only heat is permanently removed from the earth in the course of normal operations. Since the fluid, including all dissolved species, is continuously recirculated there is no pollution of the atmosphere, terrestrial waters, or the earth, and no long term residues accumulate to present disposal problems for future generations.

Can the vast store of energy in HDR be extracted economically? A number of economic studies have indicated that it can. The most recent comprehensive analysis of the costs of producing energy from HDR appeared in a report by the Energy Laboratory of the Massachusetts Institute of Technology issued in 1990 (Tester and Herzog). This work brought together a number of previous studies on HDR economics and put them on a common footing. In addition, a great deal of new information was generated. Some important results of the MIT study are summarized in Table 2.

Table 2. Busbar Costs of Electricity From High-Gradient HDR Resources*

Base Case	5.8¢/kWh
Optimized Drilling	4.2¢/kWh
Two Producers per Injection	3.8¢/kWh

*There are thousands of square miles of land with high-grade HDR potential in the Western US.

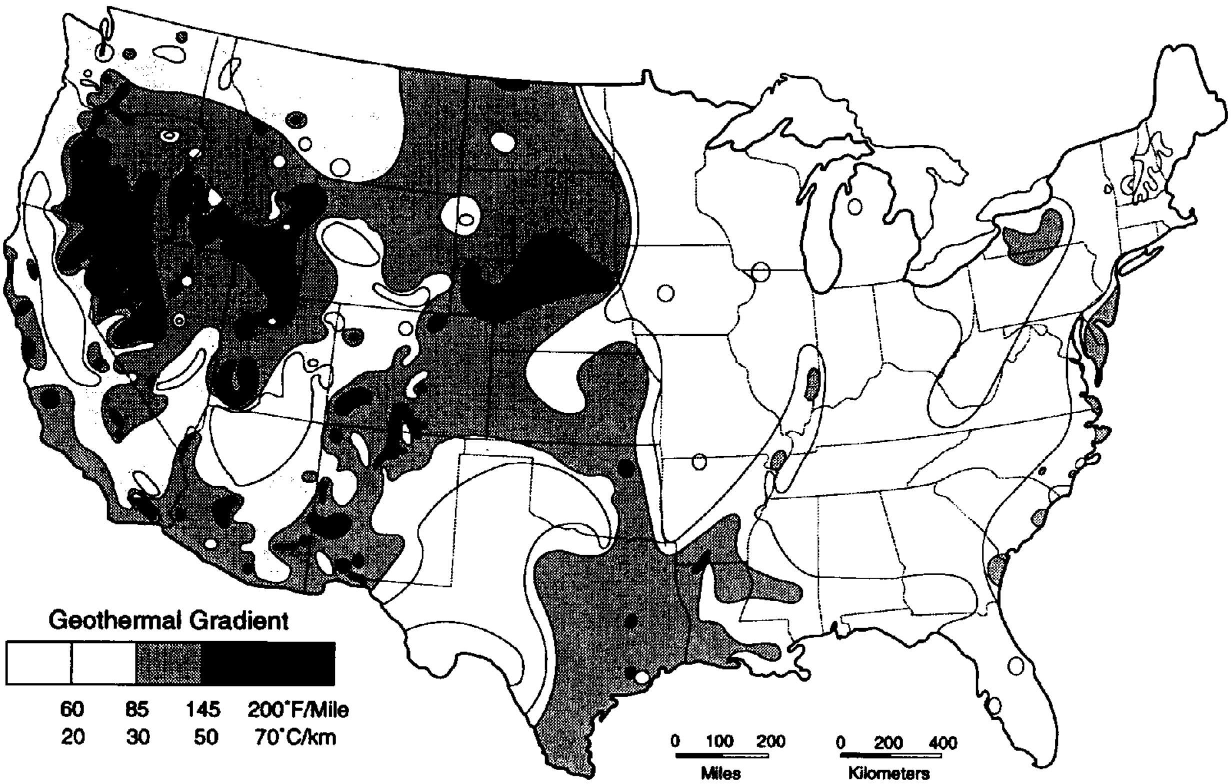

Figure 2. A geothermal gradient map of the United States. High grade HDR resources are concentrated in the west.

The data in Table 2 show that, even at the current state of technological development, electricity from high-grade HDR resources appears to be competitive with coal and nuclear energy, and while these technologies are mature, HDR is still in its infancy, with very significant cost reductions still highly probable. To date, all HDR experimental work in the United States has been conducted with two-well systems. However, as shown in Table 2, the MIT study indicates that additional operational economies could be achieved by building three-well HDR systems consisting of two producing wells and one injector. In Japan, a multiple-production-well HDR system has been developed and has shown promising technical results (Matsunaga, 1991).

Long-Term Flow Test Objectives

The LTFT will address the following issues of primary interest in future commercialization of HDR:

HDR Reservoir Thermal Lifetime: This test should demonstrate that practical amounts of energy can be extracted from the Phase II HDR reservoir over an extended time period. Studies have indicated that the Phase II reservoir has a flow-connected volume of 5-20 million cubic meters, and contains enough heat to provide high temperature fluid for many years (Robinson 1991). The LTFT will show conclusively whether or not that heat can be continuously extracted in practical amounts.

Previous extended tests of HDR reservoirs have yielded mixed results. In 1978-1980, the Phase I reservoir was flow tested in 5 segments for a total operating period of over a year (Dash, Murphy, and Cremer 1981). During the last part of that test, the fluid production temperature dropped from 158°C to 149°C over a period of about nine months while the reservoir grew in size and the impedance to flow declined. This first reservoir was undoubtedly much smaller than the current Phase II system and may have been considerably different in structure so it provides only broad guidance as to what may be expected in the current test.

The British conducted extensive flow testing of their reservoir at Rosemanowes in Cornwall, U.K., during 1985-1989 (Parker 1989). This reservoir is located at a depth of about 2 km, and has an estimated volume of 1-5 million cubic meters. The temperature of the rock is less than 100°C. Thermal drawdown on the order of 1°C per month was observed during much of the flow testing period, but this was attributed in part to the development of a short circuit causing rapid transport of water from the injection to production well with consequent inefficient heat capture. While the British test provided interesting and scientifically significant information, there is no indication that it can serve as a benchmark for expectations in flow testing of the deeper, hotter reservoir at Fenton Hill.

Reservoir Water Consumption: Water consumption has always been an issue in the operation of HDR systems. In the past, the Japanese have experienced extremely high water losses on the order of 60% or more, but in a recent test of a 4-well system, they recovered 80% of the injected water (Matsunaga 1991). The British also experienced high water losses early on but were able to keep water losses to about 20% during some phases of their circulation testing (Parker 1989).

Water losses in the range of 25% were observed at the close of the 30-day flow test of the Phase II HDR reservoir in 1986 under operating conditions leading to reservoir growth, but water consumption dropped from more than 10 gpm to less than 3 gpm over the course of a long static pressurization test of the Phase II reservoir during 1989-1991 (Brown 1991). If these results hold up in the LTFT, water consumption could be under 5% of the injected volume. Such a result would go a long way toward demonstrating that HDR plants can be built to operate with minimal amounts of makeup water.

Maintenance and Operations Issues: The surface facility at Fenton Hill was designed and constructed during 1988-1991. It has been built to industrial standards, and is highly automated. Until now, little regard has been paid to the above-ground portion of HDR plants, since development and characterization of the HDR reservoir has always been the overriding objective of previous HDR flow tests. During the LTFT, it will be practical to monitor all aspects of the performance of the surface plant. Thus it will be possible for the first time to obtain experimental data regarding parasitic power requirements, maintenance factors, scaling, and corrosion in a simulated HDR energy production facility

After the Long Term Flow Test

A Second HDR Site: The LTFT should set the stage for direct involvement in the development of HDR by the private sector. Perhaps the most important step in moving HDR toward commercialization after the completion of the LTFT will be the establishment of a second domestic HDR facility. Ideally, this installation will make full use of the technological lessons learned at Fenton Hill but will be built and operated primarily by private industry. It should be located in an area where there is a market for power and be designed to make and sell electricity at a competitive price.

Creative approaches may be required to assure that the second HDR site is economically viable. Multiple-well concepts designed to extract the maximum amount of energy at the lowest cost must be considered in designing the underground system. These are discussed in more detail below. In addition, it may be advantageous to minimize the economic risk by making HDR one component of a hybrid facility in which natural gas or another well-established fuel provides a fully-secure energy source for the substantial above-ground capital investment in power generation.

It is unlikely that private industry will bear the entire risk inherent in constructing a second domestic HDR site. The fact that it would be the world's first HDR power producer implies a higher risk level than the power industry normally assumes. Government participation may thus be required to make the development of a second site a reality. If properly conceived and executed, however, the second HDR site could set the stage for the rapid development of fully-privatized HDR installations.

HDR Research Center: A dedicated facility to further develop and advance HDR technology is needed to assure that new techniques to improve efficiency and address potential operating problems are continuously made available to HDR production plants. Reduction in the impedance to fluid flow in the reservoir body, for example, could significantly lower pumping costs and increase production rates. During the LTFT, this is being attempted through control of the backpressure on the production well.

As illustrated in Figure 3, modeling has indicated that a low pressure zone forms around the production well during flow of the system. As a result the joints in this region tend to close up but, in theory, can be propped open by maintaining an elevated backpressure at the production wellhead (Robinson 1991). By this technique, the net pressure drop across the system may be reduced without a collateral reduction in the flow rate. Preliminary results from the LTFT seem to support this contention.

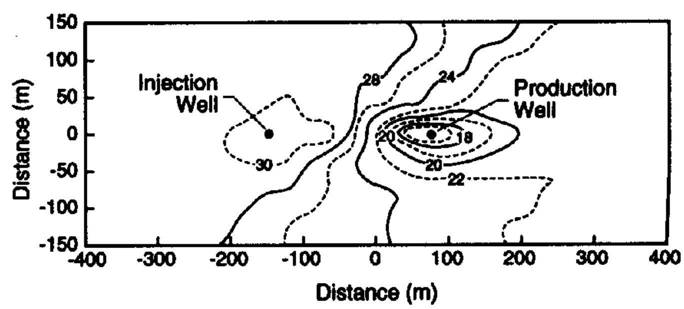

Figure 3. Simulated pressure distribution in an HDR reservoir for two-well circulation. A low pressure zone exists around the production well.

Previous attempts to reduce flow impedance have entailed jolting the reservoir with a high pressure surge in a "stress unlocking experiment" at Los Alamos (Murphy 1981) and the use of proppant materials by the British (Parker, 1989). Results were promising, but not unambiguous. Much more work needs to be done in the area of impedance reduction.

Short circuits, in which extremely rapid pathways from the injection to the production well are opened, can bring about rapid declines in HDR fluid production temperatures. Uneven cooling of the reservoir rock mass can lead to the same result. The development of sealing techniques to selectively close off unwanted flow paths would significantly advance HDR technology and improve the prospects for long-term reservoir performance.

Abrasive or chemical action by materials present in the circulating fluid may over time greatly change the nature of the flow paths within the reservoir but little is known about these effects at present. Finally, while important and novel tools for interrogating HDR reservoir have been developed, many more improvements are possible with a concerted research and development program.

All of the above efforts are important to the understanding, management, and most efficient operation of HDR reservoirs. Progress on them requires that an HDR research center dedicated to advanced research and development be maintained. It should be a joint undertaking of industry and government, and have the laboratory and plant facilities needed to carry worthwhile concepts from the initial design and testing stages all the way through field testing.

Multiple Production Wells: The LTFT is being conducted at an HDR facility consisting of one injection and one production well. Since an HDR reservoir generally forms symmetrically around the injection well, it is obvious that in any two-well arrangement, about half of the reservoir volume (that on the side opposite the production well) is wasted. In fact, calculations have indicated that the productivity of the Fenton Hill system could be increased by approximately a factor of 3, simply by addition of another production well to the system (Robinson 1991). By simultaneously applying other advanced operating strategies, the gain in productivity could be significantly greater. The Japanese have significantly improved the performance of their facility at Hijiori by the installation of multiple production wells (Matsunaga 1991).

In addition to the obvious added production possible from another outlet at a different location in the reservoir, a second production well also permits the entire system to be operated at a higher pressure. This is because production wells act as pressure relief devices in the reservoir. Experience has shown that expansion of the Fenton Hill reservoir during flow testing at high injection pressures takes place exclusively on the side of the injection well without an outlet (Duchane 1990).

Modeling, as illustrated in Figure 3, has clearly shown that production wells act as pressure sinks (Robinson 1991). The higher injection pressures made possible by two or more strategically located production wells mean that water can be pumped into the system at a greater rate and the production capacity of the system substantially increased.

Economic and technical studies have both indicated significant advantages for multiple well HDR systems. As mentioned above, it may thus be desirable to design the second HDR site as a multiple well facility in order to achieve the maximum operating efficiencies while at the same time moving HDR technology significantly forward.

Cyclic Operations: Operation of an HDR facility in the cyclic mode may offer both technical and economic advantages (Robinson 1991). In one variation of this operational strategy, water is injected under high pressure with the system shut in, the system is held at an elevated pressure for a period of time, and then a production well is opened to return the water to the surface. This water brings with it both the thermal energy absorbed during storage and much of the mechanical energy stored in the rock structure by the injection process.

In a cyclic operation, water is pumped to the far reaches of the reservoir during injection and then pushed toward the surface even from dead-end fractures by the compressive force of the reservoir rock as it relaxes during the production phase. Access to the reservoir is thus maximized. Cyclic operations also eliminate short-circuit problems by providing a fixed minimum storage period for the injected water. Thermal energy transfer is thus made independent of the pathway the water traverses between the injection and production wells.

A cyclic HDR operation could provide valuable peaking power to electric utilities. Viewed as a pumped storage facility, it might be possible to attain more than 100% efficiency, in sharp contrast to the relatively inefficient pumped storage schemes in common use today. When used as part of a hybrid system with solar or wind electric generators, cyclically operated HDR reservoirs could turn these environmentally benign but intermittent energy facilities into round-the-clock power suppliers. Alternatively, an HDR reservoir with a number of production wells could be operated in a staged mode with each individual production well cycled but overall system output maintained at a constant level.

To date, almost no experimental work has been done on cyclic operation of HDR systems. The fact that water forced into an HDR reservoir can return with incredible force was amply demonstrated, however, when a wellhead failure forced the emptying of the Phase II HDR reservoir in 1984 (Franke, et al 1986). Steam returned to the surface at an estimated power level of greater than 60 megawatts thermal during a two-day period of rapid venting and for several hours this release exceeded 100 megawatts of thermal energy. This unintended and crude experiment brought approximately 54% of the fluid stored in the reservoir rapidly back to the surface and vividly illustrated the potential of cyclic HDR production to deliver large amounts of power over a relatively short time frame. To clearly demonstrate the advantages of cyclic HDR operations, however, well designed and carefully controlled studies will be required.

Water Purification: In all the HDR facilities constructed to date, the conservation of water by continuous recirculation in a closed-loop mode has been of paramount concern. However, in some circumstances where abundant supplies of low quality water are available, it may be possible to utilize an HDR facility for both electricity generation and water purification. The need for high quality water is continually increasing around the world. At the same time vast quantities of gray water are being generated in the form of treated sewage.

An HDR facility could be designed to operate on such treated sewerage, for example. The plant could be operated in either an open-loop or partial recirculation mode to adapt to the quantities of water available. Temperatures reached underground would certainly be sufficient to destroy harmful microorganisms thus eliminating the need for chlorination. At the surface, the usual binary system could be employed to produce electricity. Excess water could then be released for other uses. Alternatively, if the hot water were free enough from minerals, it could be flashed to steam to drive a turbine directly and the steam could be recondensed for beneficial use.

Obviously the same technical approach could be used in a desalination facility to produce pure water from the sea or any of the widespread brackish groundwater sources found around the world. Because of the high mineral content typically present in such waters, techniques for removing and processing the waste salts would have to be developed or adapted from current desalination technologies.

Direct Thermal Applications: The direct use of the thermal energy from HDR for space and industrial process heating may seem like an obvious application of the technology, but significant commercial interest in this area will be aroused only when the construction of HDR systems is recognized to be highly reliable. Thermal energy is not usually marketed externally like electricity but is generally consumed by the generator. Thus it is a means to an end rather than a primary product for sale.

If HDR technology can be shown to be reliable in bringing thermal energy to the surface at almost any location, direct thermal applications will rapidly appear. Those in the geothermal power industry who have perfected HDR technology for electricity production will then be in an ideal position to exploit the opportunities for direct thermal applications. Indeed, process and space heat production from HDR may be the route to making the geothermal energy a national rather than a regional industry.

Novel Operating Fluids: Today costs and environmental considerations limit the choice of circulation fluids in HDR systems to water. In the future, however, as the technology matures, reservoir management techniques are perfected, and tighter systems are developed, other fluids may offer operational advantages. Two novel fluids seem worthy of mention even at this early stage of HDR development. Carbon dioxide is relatively cheap and is already in use in enhanced oil recovery. It is certainly practical to operate an HDR system under pressures higher than the supercritical point of carbon dioxide. Under these conditions, carbon dioxide has a density high enough so that it may act as an efficient heat transfer fluid. With carbon dioxide as the circulating fluid, it might be practical to employ a flash process to generate electric power, thereby eliminating the inefficiencies of the binary power plant. In the same manner, it may be possible to use ammonia/water mixtures directly as circulating fluids and run the facility using a version of the Kalina cycle (Kalina and Tribus 1989).

In both of these cases, a large amount of work would be necessary to demonstrate that the materials are environmentally and chemically compatible with the hot reservoir rock as well as the structural materials of the system, that systems can be built to run without excessive fluid losses, and that net efficiencies in electric power production are achievable. Even the beginning of substantial work in this area is probably 5-10 years off. The topic is addressed in this paper merely as another illustration of the many potential techniques available for increasing the efficiency of HDR operations.

Summary

It has already been unambiguously demonstrated that energy can be extracted in useful amounts from the HDR resource. The long-term flow test currently underway at Los Alamos will show that this energy can be obtained reliably over a long time period without excessive water consumption.

The next steps in making HDR technology commercial are to show that it can be applied in a variety of geographical settings and that it can be economically exploited. While studies have indicated that power plants based on conventional HDR concepts may be able to produce electricity at competitive costs, a number of as yet uninvestigated approaches may lead to further significant improvements in the efficiency of energy extraction from HDR and give the technology an economic edge.

HDR technology today is in its infancy. It might be compared to the electronics industry in the days of crystal radio sets. As that technology progressed through vacuum tubes and transistors to the highly sophisticated integrated circuits of today, so HDR can move from its current embryonic stage toward multiple well installations and cyclic operational schemes and thus fulfill its role as an ever more efficient energy source.

There is no doubt the energy is there or that it can be extracted. There is also no dearth of ideas on ways to move the technology forward toward ever greater efficiency. What is needed are strong individual and institutional commitments to see this technology through its difficult early stages to the fruits of its maturity. Those organizations with the foresight to do so will surely reap the benefits that this vast energy source can provide.

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START-UP OPERATIONS AT THE FENTON HILL HDR PILOT PLANT

Raymond F. Ponden
Earth and Environmental Sciences Division
Los Alamos National Laboratory

ABSTRACT

With the completion of the surface test facilities at Fenton Hill, the Hot Dry Rock (HDR) Geothermal Energy Program at Los Alamos is moving steadily into the next stage of development. Start-up operations of the surface facilities have begun in preparation for testing the Phase II reservoir and the initial steady-state phase of operations. A test program has been developed that will entail a number of operational strategies to characterize the thermal performance of the reservoir. The surface facilities have been designed to assure high reliability while providing the flexibility and control to support the different operating modes. This paper presents a review of the system design and provides a discussion of the preliminary results of plant operations and equipment performance.

INTRODUCTION

The next step in the development of the HDR technology is to establish the thermal performance of the Phase II reservoir at Fenton Hill. The underground reservoir is located at a depth of approximately 12,000 feet and is connected to the surface by two wells. Upon completion of this man-made reservoir in 1986, it was subjected to a circulation test to confirm flow continuity between the wells and to get an estimate of its thermal power potential. During the test, the temperature of the produced fluid rose to 375°F and a nominal 10MW of thermal power production was achieved. The reservoir performance was still improving when the test was terminated at the end of 30 days. This short test demonstrated the potential of the Phase II reservoir to produce high temperature geothermal water. Although the test produced encouraging results, there still remained the need to demonstrate that geothermal energy could be extracted on a sustained basis. To be attractive as an alternate energy source for commercial power production would require further understanding of the circulation process and a means to predict the useful lifetime of an HDR reservoir.

To seek the answers to the questions about the commercial potential of the HDR technology, a more extensive series of tests would have to be conducted to verify the reliability and longevity of power production from an HDR reservoir. These tests have been developed into a test program called the Long Term Flow Test (LTFT). The test program includes a number of operating modes to characterize the steady-state power production and long-term reservoir performance.

To accomplish the goals of the LTFT, surface facilities were designed with the flexibility and control to conduct the different tests. In designing the plant, consideration was taken to allow for the use of existing facilities, government surplus components, and commercially available equipment. Construction of the facilities was completed in the summer of 1991. Since then, efforts have been focused on accomplishing the first phase of the LTFT plan, i.e. start-up operations. The purpose of this phase is twofold. The first is to verify equipment performance and evaluate overall plant operations. The second is to assess the relationship between operating pressures and production flow rates and to establish the operating parameters for optimum energy extraction.

SURFACE PLANT

The surface plant contains equipment to perform the following major functions: 1) develop the required pressures to circulate water through the reservoir, 2) remove the heat energy from the hot geothermal fluid, 3) measure and control the fluid temperature, pressure and flow, 4) remove any gases and solids from the fluid, and 5) add water to the process stream.

The plant is designed to operate at pressures above the vapor pressure of the circulated fluid. Circulation of water through the reservoir is created by a pair of positive displacement pumps that deliver water under high pressure to the reservoir through the injection well. After passing through the reservoir and extracting the heat energy from the fractured rock, the water is returned to the surface via the production well. At the surface, the hot geothermal water passes through a pressure regulating station then on to a separator where any gases or solids are removed from the process stream. The hot fluid then flows to the heat exchanger where it is cooled and the extracted heat energy is measured. After cooling, the fluid is returned to the injection pumps to complete the cycle. Water that is lost during the circulation process is replenished from a 5 million gallon storage facility. The makeup water is pumped into the low pressure side of the plant by two centrifugal pumps. The surface facilities are illustrated in the basic schematic of Figure 1.

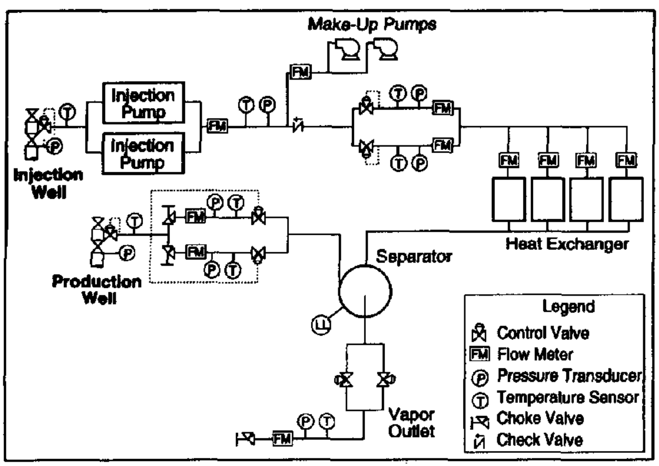

Figure 1. Schematic Diagram.

From a pressure standpoint, the plant can be divided into three sections - the production, low pressure, and high pressure segments. The production segment consists of the regulating equipment adjacent to the production well to reduce the pressure of the hot geothermal fluid to the low pressure segment of the plant. The low pressure segment consists of the separator, heat exchanger, makeup pumps and interconnecting piping. The high pressure segment consists of the injection pumps and the piping to the injection well.

For the circulation of water through the reservoir, the rate of flow is established by maintaining control of the pressures at the wellheads. The control scheme for plant operations is to maintain constant pressures on the production and injection wells. The pressure on the injection well is controlled by the speed of the injection pumps. On the production well, pressure control is achieved by throttling the flow through a combination of manual choke and pneumatic control valves. The first stage of throttling is accomplished by the choke valves. The pneumatic control valves provide the second stage of throttling and maintain the constant pressure on the wellhead. Their operation is controlled as a function of the production line pressure upstream of the choke valves. Pressure in the low pressure segment of the plant is maintained by the two makeup pumps. Depending on demand, the pumps will operate singularly or in parallel to maintain a constant suction pressure to the injection pumps.

SYSTEM PERFORMANCE

As part of the start-up operations, two circulation tests were conducted at different production pressures to evaluate the relationship between operating pressures and flow rates. The test period for each of the tests was three (3) days. A summary of the results is presented in Table 1.

Table 1. Test Results

Test Number	1	2
Injection Pressure, psi	3,700	3,865
Production Pressure, psi	2,210	1,510
Production Rate, gpm	74	101
Water Consumption, gpm	10	12
Power Production, kw	2,665	4,225
Pumping Power, kw	65	125

In the first test, production temperatures reached 310°F at an average production rate of 74 gpm while in the second test the temperature had climbed to 350°F at an average production rate of 101 gpm.

The pumping power represents the hydraulic power requirements. It is the combination of the power to inject the water into the reservoir and to add water to the process. The pumping power for each test was less than 3% of the total thermal power production.

The water consumption is the amount of water that was added to the process as a result of circulation losses through the reservoir. The water requirements of 10 and 12 gpm equate to losses of 11.9% and 10.6% of the total injected fluid. The water consumption is expected to decrease under long term operations of the reservoir.

Samples of the production fluid were also collected and analyzed during these circulation tests. As part of the analysis, dissolved gases were separated from the production fluid. The amount was found to be less than .1% of the total weight. As expected, 90 to 95% of the gas was carbon dioxide. Other gases included hydrogen sulfide, nitrogen, and oxygen. An analysis was also made for solids. Total suspended solids (TSS) were found to be less than 100 ppm.

EQUIPMENT PERFORMANCE

Injection Pumps. The pressure for circulating water through the reservoir is developed by a pair of quintuplex type, reciprocating pumps. The pumps can produce flow rates in the range of 84 to 336 gpm at pressures from 3400 to 5000 psi. An illustration of a pump is provided in Figure 2.

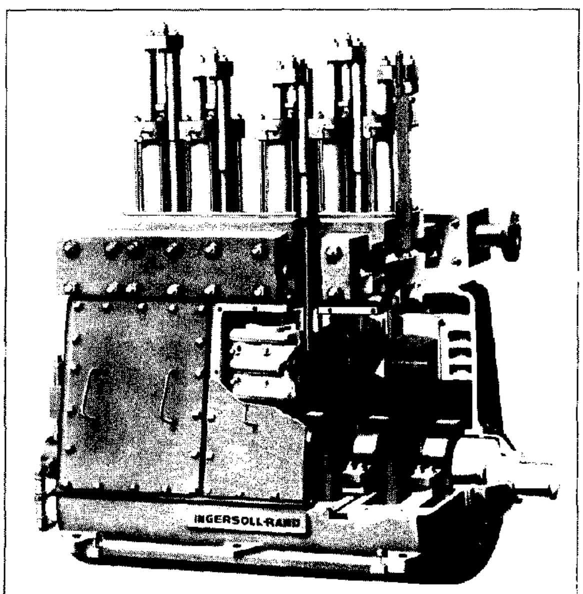

Figure 2. Injection Pump.

The pumps were subjected to approximately 700 hours of operation. Both pumps were used in the start-up operations but not in combination. Flow rates for the operations required the use of only one pump at a time. Early into the start-up phase, one of the pumps developed a mechanical problem in its power end that was traced to a defective crank bearing. The problem was quickly remedied by the pump manufacturer. After the repair, the pump was placed back into service without any further mechanical problems.

An inspection of the pump valves uncovered a seemingly high rate of wear on the sealing surfaces on both the discharge and suction valves. This condition was evident in both pumps. However, there was no degeneration in the hydraulic performance of the pumps. Further pump operations will be needed to establish information on the life cycle of the valves.

Separator. The separator is designed to remove any free vapor and suspended solids from the hot geothermal fluid. It is designed to remove 350 lbs/min of vapor and approximately 3 lbs/min of solids.

During the circulation tests, there were brief periods of operation when undissolved gas was produced as part of the production fluid. In these instances, the separator operated to effectively remove the gas from the process stream. As compared to the 30-day test in 1986, the gas production was less frequent and shorter in duration. The difference has been attributed to the higher production pressures in the more recent tests.

The production of sediment was essentially nonexistent. During one of the 3-day circulation tests, less than 1 gram of sediment was removed from the separator.

Makeup pumps. Previous testing of the Phase II reservoir confirmed that water is lost in the process of circulating water through the reservoir. This loss varies depending on the reservoir pressure. To compensate for the loss, water is added to the process in the low pressure side of the plant by a pair of centrifugal pumps. The pumps can supply water at rates from 5 to 74 gpm at pressures between 250 to 1000 psi.

A minor problem in commissioning the makeup pumps was encountered with the control logic. The pumps came furnished with control equipment that was to provide for automatic operations. Depending on the demand, the control system was to activate and sequence the pumps to supply the needed water and maintain a steady pressure. The problem was remedied by the pump vendor with a redesign of the control logic and the installation of additional control equipment.

Heat Exchanger. The thermal energy is removed from the geothermal fluid as it passes through an air-cooled heat exchanger. The heat exchanger is modular in design and contains four (4) separate finned-tube bundles. The finned tubes are constructed from ASTM A-214 carbon steel material.

The heat exchanger is part of the existing equipment at Fenton Hill that was incorporated into the design of the surface plant. It has been used periodically since the start of the HDR program to support other circulation experiments. Because of its age and the susceptibility of the tube material to corrosion, an internal inspection was made to evaluate the condition of the tubes prior to placing it into service. The inspection uncovered a buildup of iron carbonate scale but no degradation in the material thickness of the tube wall. The decision was made to proceed with using the heat exchanger in its present condition.

During the testing, all four bundles were evaluated but only two were required at any given time for cooling the fluid. The pressure drop through one of the bundles was found to be higher than the remaining three. This was attributed to the fewer number of tubes in the bundle. The operating parameters for the next test phase in the LTFT program are going to be similar to those in the start-up operations. The present plan is to use the heat exchanger without any additional changes and continue to evaluate its performance.

Plant Control. The plant is designed for automated operation. Process control along with the collection of operating data is performed by a high speed data acquisition and control (DA&C) system. The system consists of commercial software for process automation running on a PC-based computer.

The implementation of the computerized control system progressed smoothly and without major problems throughout the start-up phase. The control logic has been verified and the system can provide for an automated shutdown in the event of an upset from normal operating conditions. The objective for system automation is to provide for extended unmanned operations. Work continues on developing the necessary operational and control logic to accomplish this goal.

SUMMARY

The start-up operations succeeded in verifying the equipment and system performance of the HDR surface plant. In addition, it provided valuable information regarding operating parameters for conducting the next test in the LTFT plan. Additional operating time will be necessary to establish the reliability and maintenance requirements of the equipment in the plant. The success of the start-up operations completes another milestone in the program to develop the HDR technology as a commercially viable energy source.

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UPDATE ON THE LONG-TERM FLOW TESTING PROGRAM

Donald W. Brown
Los Alamos National Laboratory

ABSTRACT

Preliminary flow and pressure testing of the Phase II Hot Dry Rock (HDR) reservoir at Fenton Hill, New Mexico, as part of the preparations for the initial 90-day segment of the Long-Term Flow Test, has revealed several significant features concerning the hydraulic behavior of this reservoir as a function of injection and production pressure levels.

Of most significance to the future operation of HDR power plants is the influence of elevated production backpressure on the effective reservoir flow impedance (i.e., the difference between injection and production pressures, divided by the production flow rate). It has been found that the effective flow impedance at high backpressure is significantly lower than the corresponding impedance at low backpressure. At an injection pressure of 3700 psi and a back-pressure of 2210 psi, the effective flow impedance for the present reservoir is 20 psi/gpm -- less than 40% of the effective flow impedance for similar injection conditions, but at low backpressure (about 170 psi).

Recently, a 10-day reservoir flow test was conducted at a somewhat lower backpressure of 1500 psi, and at a slightly higher injection pressure of 3750 psi. At these new conditions, there was an increase in the effective reservoir flow impedance to 23.6 psi/gpm, but also a significant increase in the production flow rate and temperature -- from 74 gpm to 95 gpm, and from 154°C to 180°C. The net reservoir water loss rate averaged over the last 5 days of this latest flow test was 7.3 gpm, which corresponds to a net recovery of 93% of the injected water -- a very significant result that has been obtained from our preliminary reservoir flow testing.

Under both of these high backpressure flow conditions, the reservoir was not extending, as evidenced by a very low rate of water loss and the absence of microseismic activity.

INTRODUCTION

Beginning in early December of 1991 and continuing through February of this year, we conducted a series of surface system checkout tests combined with some preliminary reservoir flow testing. These brief (typically 3-day) flow tests were a consequence of the need to produce the reservoir in order to check out, under true production conditions, the the newly installed or extensively modified surface production equipment such as the gas separator, the make-up water pumps, and the production wellhead assembly. The first, and most significant, of these flow tests is here referred to as Test 1.

On 2 March, the reservoir was inflated to about 3100 psi in preparation for the initial 90-day aseismic phase of the Long-Term Flow Test (LTFT) beginning the next day. The primary objective of this first phase of the LTFT was to continuously operate the Phase II reservoir at the highest attainable aseismic injection pressure, while maintaining a constant production well backpressure in the range of 1000 to 2000 psi. The initial operating parameters were specified as:

Injection Pressure:	3900 psi
Production Backpressure:	1500 psi

However, after ten days of reservoir circulation, the test -- here referred to as Test 3 -- was temporarily halted so that additional flexibility could be built into the production piping. This added flexibility was necessary to accommodate a greater-than-anticipated movement of the production wellhead assembly, which in turn was the result of the thermal expansion occurring in one or more of the several concentric casing strings below the production wellhead, most of which had been installed 10 years previously during the initial drilling of well

EE-2.

Table I summarizes the final operating conditions for these two reservoir flow tests.

Table I

Operating Conditions During Preliminary Flow Testing		
Dates (1991 and 1992)	Test 1 12/4-12/7	Test 3 3/3-3/13
Injection Conditions		
Pressure, psi	3700	3750
Flow Rate, gpm	86	111
Production Conditions		
Pressure, psi	2210	1500
Flow Rate, gpm	74	95
Temperature, °C	154	180

Test 1, with a production backpressure level closer to the pre-existing static reservoir pressure level of 3100 psi, appears to have been rapidly approaching steady-state operation at the end of only 3 days, whereas Test 3 required almost 7 days to similarly approach steady state.

RESULTS FROM TEST 1

Figures 1 and 2 show the injection and production flow rates and pressures during this brief 3-day flow test, primarily to demonstrate the rapid approach to steady-state operation. Following 24 hours of reservoir inflation which ended at about noon on December 4 at a shut-in pressure of 3100 psi, production flow was initiated in two steps, with the production flow rate rapidly decreasing during the next 17 hours as the reservoir reached pressure equilibrium from the higher pressure condition. After 3 days of circulation, as can be seen from Fig. 1, the production flow rate had almost leveled off at a rate of 74 gpm with a near constant injection rate of 96 gpm. Based on other flow testing, the injection pressure shown in Fig. 2 would have continued to slowly drop beyond 3 days of operation due to the continued cooling of the rock, and the resulting thermal dilation of the joints in the vicinity of the reservoir injection interval.

Figure 3 shows the corresponding production fluid temperature rise during this same time interval. After having initially risen quite rapidly during the ventdown of the reservoir

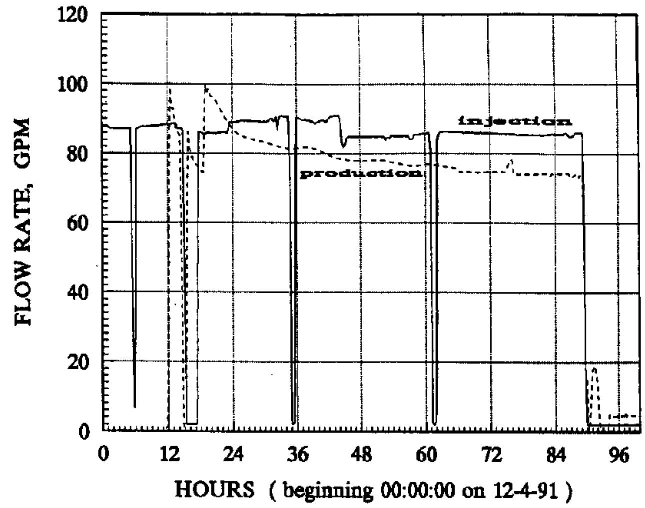

Figure 1. Injection and production flow rates for Test 1.

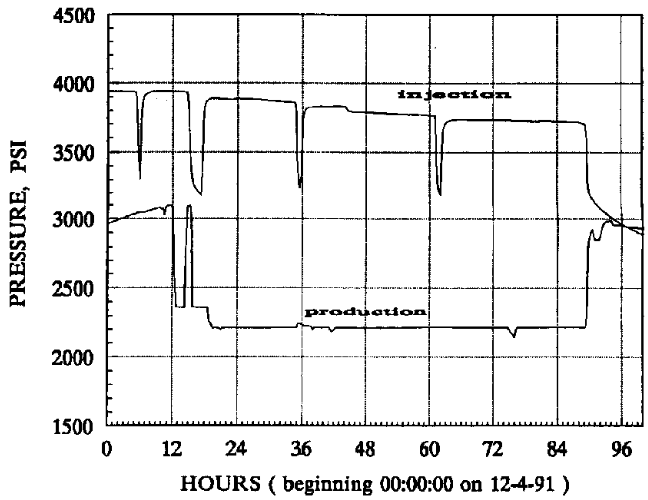

Figure 2. Injection and production wellhead pressures for Test 1.

from its inflated state of 3100 psi in the vicinity of the reservoir production interval, the temperature continued to rise more slowly to the end of the third day. This profile suggests that the production fluid temperature was asymptotically approaching a level of about 160°C. The produced thermal power near the end of this test was 2.66 MW at a surface injection temperature of 18°C.

RESULTS FROM TEST 3

Most of the results from Test 3 are summarized in Table I, except as discussed later in the Impedance and Water Loss sections. During the last 3 days of this test, the measured performance indicated that the reservoir had essentially reached steady state operation

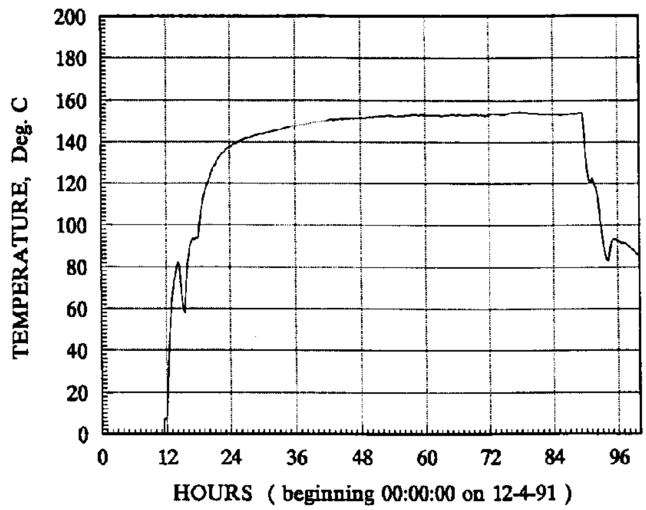

Figure 3. Production well temperatures for Test 1.

except for the production fluid temperature. This temperature was still rising at about 0.4°C/day averaged over the last 3 days. Figure 4 shows the production fluid temperature profile for Test 3, which demonstrates how flat the curve had become near the end of the test. The produced thermal power at the end of 10 days was 3.97 MW at a surface injection temperature of 21°C.

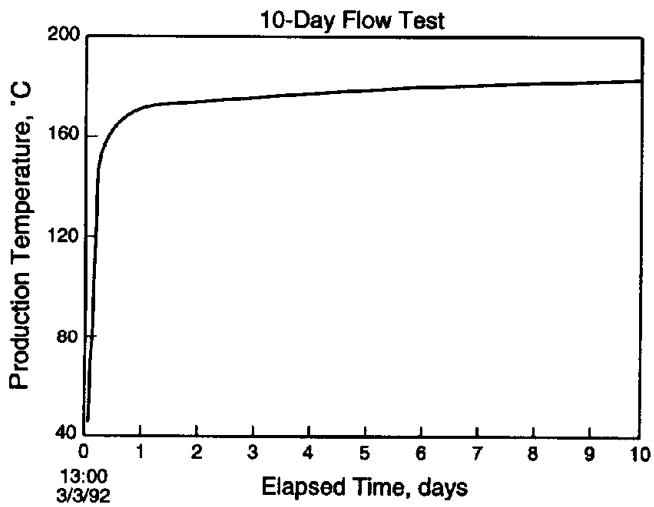

Figure 4. Production well temperature for Test 3.

RESERVOIR FLOW IMPEDANCES

The flow impedance *across* an HDR reservoir is normally divided into the following component parts: a body impedance, a near-wellbore inlet impedance, and a near-wellbore outlet impedance. Then, these component impedances are summed into an *overall* reservoir flow impedance which, however, cannot be directly measured. This is because the overall reservoir flow impedance should not include the effects of the additional differential pressure across the reservoir due to the difference in fluid density between the cold injection and hot production wellbores -- the buoyant drive, or wellbore frictional losses, since it is computed for ***downhole*** conditions at the mean reservoir depth.

1. Effective Reservoir Flow Impedance

Let us here define the ***effective*** reservoir flow impedance I_e as simply the injection pressure minus the production backpressure divided by the production flow rate. This impedance, which can be directly measured, takes credit for the buoyant drive across the reservoir at the mean reservoir depth of 11,600 ft, and also accounts for the small wellbore frictional losses (about 20 psi for the injection wellbore and 2 psi for the production wellbore). This would be the impedance of most interest to an HDR power plant operator since it would represent his injection pumping power requirements. Using this approach and the data given in Table I above, the effective reservoir flow impedance near the end of Test 1 was:

$$I_e = (3700 - 2210)/74 = 20.1 \text{ psi/gpm}$$

Similarly, for Test 3,

$$I_e = (3750 - 1500)/95 = 23.6 \text{ psi/gpm}$$

For comparison, the effective reservoir flow impedance at low back-pressure (170 psi), as measured near the end of the 7-day reservoir flow test performed in late 1987 following the redrilling of the production wellbore (EE-2A) through the Phase II reservoir region, was:

$$I_e = (3475 - 170)/63.7 = 51.9 \text{ psi/gpm}$$

The relevant performance data for the 7-day flow test of the re-completed Phase II reservoir are given in Table II below. It should be pointed out that the injection pressure of 3475 psi for this flow test is somewhat lower than for either Tests 1 or 3, and thus would tend to *decrease* the effective impedance for the 7-day flow test conditions relative to the existing reservoir inlet conditions for Tests 1 and 3. This decrease in injection pressure for the 7-day flow test probably reflects the residual effects of cooling near the injection interval induced during previous reservoir flow testing.

Table II

Final Operating Conditions for the 7-Day Reservoir Flow Test Conducted in December, 1987	
Injection Conditions	
Pressure, psi	3475
Flow Rate, gpm	93.1
Temperature, °C	17
Production Conditions	
Pressure, psi	170
Flow Rate, gpm	63.7
Temperature, °C	125

Although the operating conditions given in Table II differ somewhat from those for Tests 1 and 3, it is evident that the effective Phase II reservoir flow impedance under conditions of low backpressure is up to 2-1/2 times greater than that under conditions of high backpressure. This impedance difference in all probability reflects how tightly the joints connecting the body of the reservoir to the production interval are being held closed by the earth stresses.

2. Reservoir Component Flow Impedances

For an adequate understanding of the temporal variations in reservoir flow performance, an analysis of the corresponding changes in the component reservoir flow impedance terms offers a better way of evaluating the separate effects of reservoir pressurization and cooling. These component flow impedances are the near-wellbore inlet impedance, the reservoir body impedance, and the near-wellbore outlet impedance.

To evaluate the near-wellbore inlet and outlet flow impedances, it is first necessary to determine the equivalent injection and production pressures under no-flow conditions. This is done by measuring the corresponding wellhead instantaneous shutin pressures (ISIP) at intervals during the flow testing. For the injection well, this is the pressure that one would observe if pumping were to be abruptly stopped, with the elimination of both the pressure drop from the wellbore into the body of the reservoir and the frictional pressure drop in the tubing string. Conversely, for the production well, this would be the pressure that one would observe when both the pressure drop from the body of the reservoir into the wellbore and the frictional pressure drop in the casing were eliminated by abruptly stopping production flow.

I am here adopting the method as first proposed by Bob Potter (Potter, 1991) to determine these ISIP values from shutin data. His method is as follows: After a few minutes or up to an hour (depending on which wellbore we are considering and the duration of the test), the pressure response of the shut-in well is essentially linear with time. Prior to this time, the shut-in pressure asymptotically approaches this linear profile -- rising to meet the linear profile at the production wellhead, and dropping to meet the corresponding linear profile at the injection wellhead. By extrapolating the linear profile back to the shut-in time, one is able to arrive at a good estimate for the corresponding ISIP. Using this approach, the final ISIP values for each wellbore for Tests 1 and 3 were as follows:

	Test 1	Test 3
Injection Wellhead, psi:	3240	3640
Production Wellhead, psi:	2710	2860

Based on the above discussion, the Phase II reservoir inlet and outlet flow impedances are defined as follows:

Near-wellbore Inlet Impedance: The injection pressure (less the tubing frictional loss) minus the injection well ISIP, divided by the injection flow rate. This pressure difference is referred to as the near-wellbore pressure drop ΔP_{in} for the injection well.

Near-wellbore Outlet Impedance: The production well ISIP minus the production well back-pressure (after adding the small casing frictional loss), divided by the production flow rate. Similarly, this pressure difference is referred to as the near-wellbore pressure drop ΔP_{out} for the production well.

To evaluate the reservoir body impedance, it is also necessary to determine the ***downhole*** pressure P_d in each wellbore to account for the additional buoyant drive across the body of the reservoir. This is done by computing the integral mean fluid density from the surface to the mean reservoir depth of 11,600 ft for each wellbore to obtain the hydrostatic component of the fluid pressure at the reservoir inlet and outlet. The reservoir body impedance is then defined as follows:

Reservoir Body Impedance I_b : The *difference* between the injection well downhole pressure P_{di} minus the near-wellbore pressure drop, and the production well downhole pressure P_{dp} plus the near-wellbore pressure drop, divided by the production flow rate Q_p.

$$I_b = [(P_{di} - \Delta P_{in}) - (P_{dp} + \Delta P_{out})]/Q_p$$

These mean wellbore fluid densities would normally be obtained from the property data for liquid water using the measured wellbore temperature profiles. However, since we did not log either wellbore during Tests 1 or 3, the temperature profiles were estimated from previous flowing temperature logs, the measured surface fluid inlet and outlet temperatures, the known in situ rock temperature of 232°C for the production well downhole temperature, and an estimated cooldown temperature of 60°C for the injection well downhole temperature. (As an aside, the density difference between the injection and production wells at a mean reservoir depth of 11,600 feet was equivalent to an additional buoyant pressure drive of 596 psi for Test 1 and 693 psi for Test 3.)

In summary, these component reservoir specific flow impedances for Tests 1 and 3 were:

Impedance (psi/gpm)	Test 1	Test 3
Inlet	5.1	0.8
Body	15.2	15.5
Outlet	6.7	14.3
Overall	27.0	30.6

It is significant to note that under two different levels of high backpressure -- 2210 psi during Test 1 and 1500 psi during Test 3, the reservoir body impedance remained essentially constant, but the near-wellbore outlet impedance was markedly affected. For a decrease in back-pressure of only 710 psi (32%) between these two flow tests, the outlet impedance increased by over a factor of two.

The decrease in the near-wellbore inlet impedance between these two tests primarily reflects the amount of cooling at the reservoir inlet. Test 1 was conducted for only 3 days at an 86 gpm injection rate relative to the 111 gpm injection rate for the 10-day Test 3. As a comparison, during the first flow segment of the 30-day Initial Closed-loop Flow Test (ICFT) (Dash, 1989), the inlet flow impedance leveled off at a value of 0.4 psi/gpm after 14 days of injection at 179 gpm.

RESERVOIR WATER LOSS

Near the end of Test 1, the injection rate was 85.8 gpm and the production rate was 74.1 gpm -- an apparent water loss rate of 11.7 gpm. However, 2.0 gpm of this water loss was actually due to the additional production flow out the annular bypass flow path at the injection well. When this is accounted for, the *net* reservoir water loss rate due to permeation outflow at the periphery of the reservoir was only 9.7 gpm (89% recovery of the injected flow). Similarly, for Test 3, the *net* reservoir water loss rate, averaged over the last 5 days, was 7.3 gpm (93% recovery of the injected flow).

The only way of assessing the significance of these water loss rates during circulation under aseismic conditions is to compare them to the results from the Extended Static Reservoir Pressure Testing (Experiment 2077), conducted from March 1989 through November 1991. For the most recent 2760 psi pressure plateau of Experiment 2077, conducted in late 1990, the measured ***static*** water loss rate after 3 days of pressure maintenance was 9.3 gpm, as shown in Fig. 5 (the 2760-psi pressure plateau was begun on 26 Nov.). This value is very close to the measured water loss rate of 9.7 gpm at the end of the 3-day Test 1. This would suggest that near the end of this brief flow test, the mean pressure at the periphery of the Phase II reservoir would have been about 2760 psi.

Similarly, after about 7-1/2 days of circulation (the mid point of the 5-day average), the measured water loss rate for Test 3 was 7.3 gpm. The corresponding water loss rate from Fig. 5 (for 12 Dec.) is 8.1 gpm. These two values are again quite close, suggesting that the mean pressure at the periphery of the reservoir for

Test 3 was also close to 2760 psi.

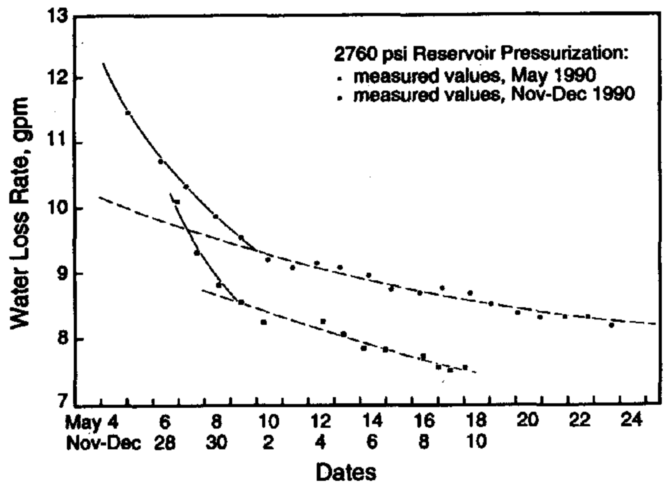

Figure 5. Reservoir water loss during two periods of pressure maintenance.

In marked contrast, Table III gives the final reservoir water loss rates measured for the two flow segments of the 30-day ICFT conducted in 1986 (Dash, 1989). It should be noted that at these times during the ICFT, the reservoir was actively growing as evidenced by a significant level of microseismic activity.

Table III

Reservoir Water Loss Rates during the ICFT

Date	Injection Rate gpm	Production Rate gpm	Water Loss Rate gpm (%)
6-2-86	179	135	44 (24.6)
6-18-86	290	214	76 (26.2)

SUMMARY AND CONCLUSIONS:

1. For the Phase II reservoir at Fenton Hill, the ***effective*** reservoir flow impedance at high backpressure is only about 40% of that at low backpressure. This very significant result was obtained by comparing the high backpressure reservoir flow performance for Tests 1 and 3 to the previous low backpressure flow performance of the reservoir in late 1987, following the re-drilling of the production wellbore.

2. It is thus apparent that reservoir production under high back-pressure conditions will result in a higher production flow rate, and therefore a higher level of power production. However, we are still in the process of determining the backpressure level which produces the maximum power production. At this juncture, it appears that a backpressure level of 1500 psi is close to, but that 2200 psi is too high for, optimum power production under the present restricted injection pressure limit of from 3700 to 3900 psi. (This injection pressure limit was imposed to preclude additional reservoir growth by the opening of joints -- i.e., fracture extension -- at the periphery of the reservoir.)

3. The component reservoir flow impedance most affected by the level of production backpressure is the near-wellbore outlet impedance, while the reservoir body impedance appears to be almost unaffected.

4. The reservoir water loss rates for these two brief flow tests were 9.7 gpm and 7.3 gpm respectively, which are both approximately consistent with a mean reservoir pressurization level of 2760 psi as observed during the static reservoir pressure testing of Experiment 2077. The loss rate for Test 3 -- 7.3 gpm -- indicates that we were recovering over 93% of the injected fluid for these aseismic test conditions of 3750 psi injection pressure and 1500 psi production backpressure.

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