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AN INJECTION TURNABOUT SUCCESS AT STILLWATER, NEVADA

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ABSTRACT

The Stillwater geothermal power plant is a 12.5 MW binary air-cooled plant that went on line in April 1989. Thermal breakthrough to the production wells began soon after plant operation began.

The initial average inlet temperature to the power plant was 332°F. By the end of 1991 the inlet temperature had declined to 268°F. After evaluation of the various options a detailed remediation plan was prepared and implemented.

Two new injection wells were drilled, two injection wells recompleted and the injection of spent geothermal brine was redistributed through the field.

With changes in the injection system the inlet temperature to the power plant recovered to 320°F, an increase of 52°F.

INTRODUCTION

Cooling of geothermal production wells by injection water can severely impact the productivity of a geothermal power plant. This is, and has been, a problem throughout the geothermal industry in a variety of geologic settings and to varying degrees. The Stillwater, Nevada plant, owned jointly by OESI Power Corp. and Constellation Energy Corp., was one of those cases of cooling of the production wells by injectate prematurely returning to the production wells.

The Stillwater geothermal power plant is a 12.5 MW binary air-cooled plant using 14 Ormat Energy Converters (OECs) and is located about 15 miles ENE of Fallon, Nevada. The production from the resource started as a closed system with all the production and injection (5,500 gpm) being cycled through a single permeable zone at depths between 1,000 feet and 1,500 feet.

The Stillwater plant went on line in April 1989. Cooling of the production wells began almost immediately after plant operation began and the use of one well was suspended after only 20 days of production.

The initial average inlet temperature to the power plant was 332°F. By the end of 1991 the inlet temperature had declined to 268°F. After evaluation of the various options through use of analytical modeling and reassessment of the entire resource a detailed remediation plan was prepared and implemented.

This plan substantially altered the field management. Two new injection wells were drilled, two injection wells were recompleted and the injection of spent geothermal brine was redistributed through the field. With changes in the injection system to increase separation between the injection and production wells and to change the distribution of the injectate, the inlet temperature to the power plant recovered to 320°F, an increase of 52°F.

Geothermal systems are dynamic systems: fluid moves into them, is heated and then moves out of them. Understanding the basic flow paths in the Stillwater geothermal system was the key to reversing the cooling of the production wells because of thermal breakthrough.

HISTORY

The history of known geothermal activity in the Stillwater area dates back to 1919 when hot water was encountered in a shallow well. Following that early discovery a number of hot wells were drilled in the area and some were used for space heating. The store at Stillwater and the Stillwater School were two of the better known buildings heated with geothermal water.

In 1964 O'Neill Geothermal Inc. drilled the Reynolds No. 1 well (R-1) about one mile NNW of the Stillwater Store (Fig. 1). The well was drilled to a depth of 4,237 feet. The maximum temperature recorded was 277°F at a point of temperature reversal.

Phillips Petroleum Company became interested in the area because of the hot wells in the area and drilled a number of temperature-gradient holes in 1972 or 1973. Although there were high temperatures and high thermal gradients in those drill holes, the geochemistry of the geothermal brines indicated that reservoir temperatures were less than the 400°F used as a minimum target temperature. No leases were acquired and no deep drilling was done.

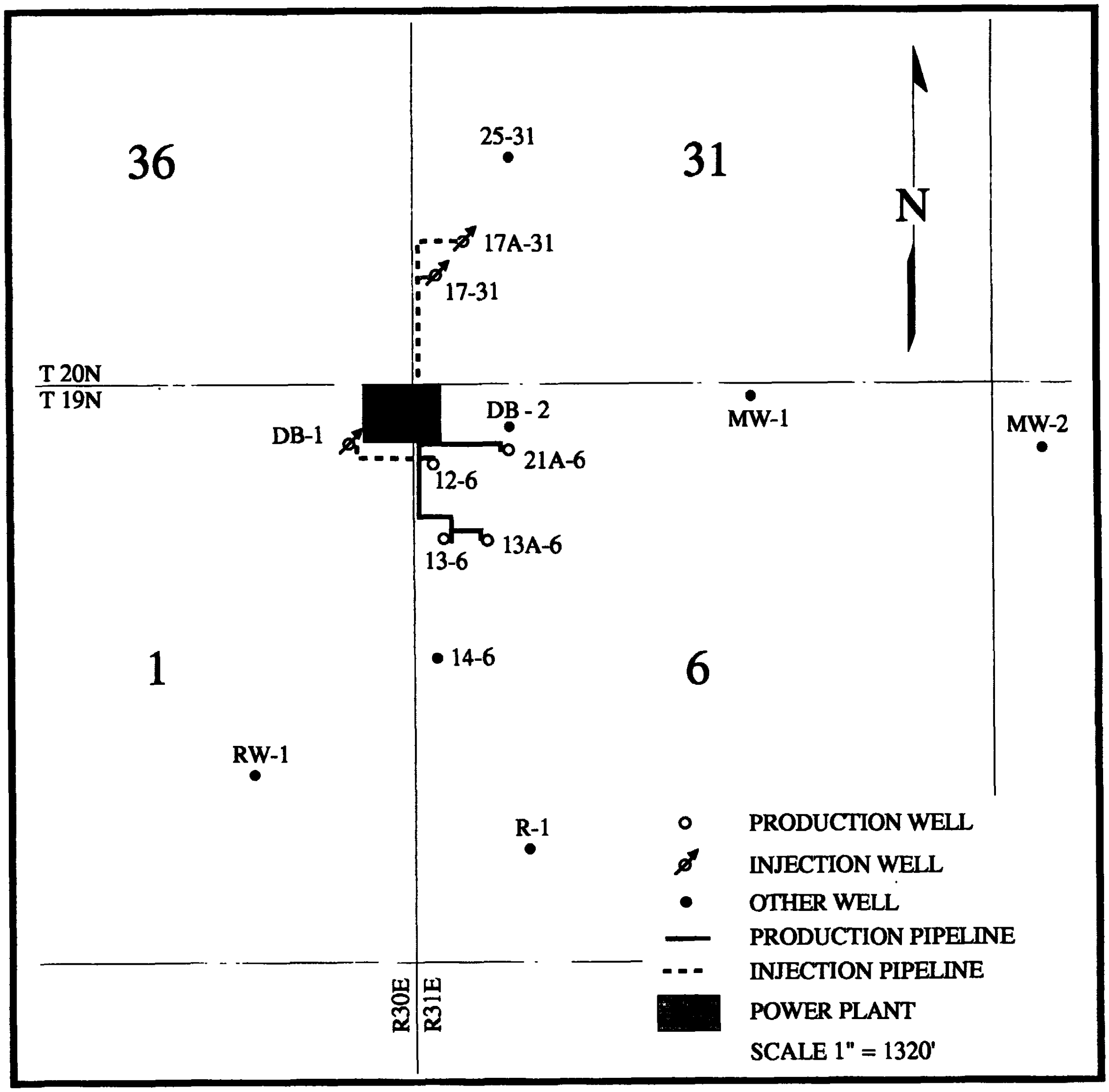


Figure 1: Stillwater Well Layout Before Remediation

Following that work Union Oil Co. acquired leases in the area, drilled additional temperature-gradient holes and then drilled four deep wells in 1976 and 1977 to depths between 3,000 feet and 10,000 feet. Those wells were MW-1, MW-2, RW-1 (Fig. 1) and W-1 (not shown on any figure). None were commercially productive and none reached a temperature of 400°F.

Transpacific Geothermal Co. then acquired the geothermal leases from Union Oil Co. Transpacific did some geophysical work but did not do any drilling.

Ormat (predecessor to OESI Power Corp.) acquired the geothermal leases from Transpacific Geothermal Co. and drilled four shallow production wells that produced fluid in the temperature range of 325°F and three injection wells. To utilize part of the resource Ormat constructed a 12.5 MW power plant using binary technology. At that time the Stillwater plant was the largest-capacity air-cooled binary geothermal power plant in the United States.

GEOLOGY

The Stillwater geothermal area (Fig. 1) is underlain by a section of poorly consolidated to unconsolidated fine-grained sediments of Quaternary age. The sediments of Quaternary age overlie a section of poorly consolidated sedimentary rocks with interbedded basalt flows of Tertiary age (Fig. 2).

The Quaternary section consists mainly of clays, silts and some sands. The rocks in the Tertiary section consist mostly of fine-grained sandstones, silty shales and soft clays. Within the Tertiary section there are discontinuous basalt flows up to 450 feet thick. Sedimentary units of both Quaternary and Tertiary ages were deposited in a lacustrine environment.

The bulk of the Stillwater production is from a poorly consolidated sandstone of Quaternary age and is referred to as the Production Sand. In the Stillwater production area the Production Sand is at a depth of 1,500 feet, or less, and has been silicified by deposition of silica from geothermal fluids. It is laterally extensive but overall has limited primary permeability. Permeability of the Production Sand in the area of the production and injection wells has been enhanced by fracturing along a fault zone which strikes roughly north-south.

The fault zone also provides a vertical conduit which provides a small portion (probably less than 200 gpm) of deep recharge to the Production Sand in the immediate area of the production wells. Based on temperature distribution in the system, the inferred direction of pre-production flow indicates that the bulk of the geothermal fluid migrated to the south or southwest through the Production Sand (Fig. 2). This flow pattern was evidenced by temperature reversals seen in some of the old wells (R-1, DB-1 and DB-2) and by the intensity and shape of the thermal anomaly outlined by shallow temperature-gradient holes.

It was thought that this flow path would be beneficial to temperature recovery by injecting "upstream" a sufficient distance to let the injectate heat up before it returned to the production wells. Injecting "upstream" would also provide some pressure support to the production wells and discourage the incursion of cooler waters contained in lateral equivalents of the Production Sand and in overlying sediments.

In the area of the production wells both the Tertiary basalt flows and the sedimentary rocks have for the most part sub-commercial permeability as evidenced by the RW-1, MW-1, MW-2, R-1 and 21-31 wells which all have depths in excess of 3,000 feet. However, one production well, DB-1, produces from a fractured basalt unit in the section of Tertiary rocks and receives pressure support from injection into the basalt via the 17-31 well. The

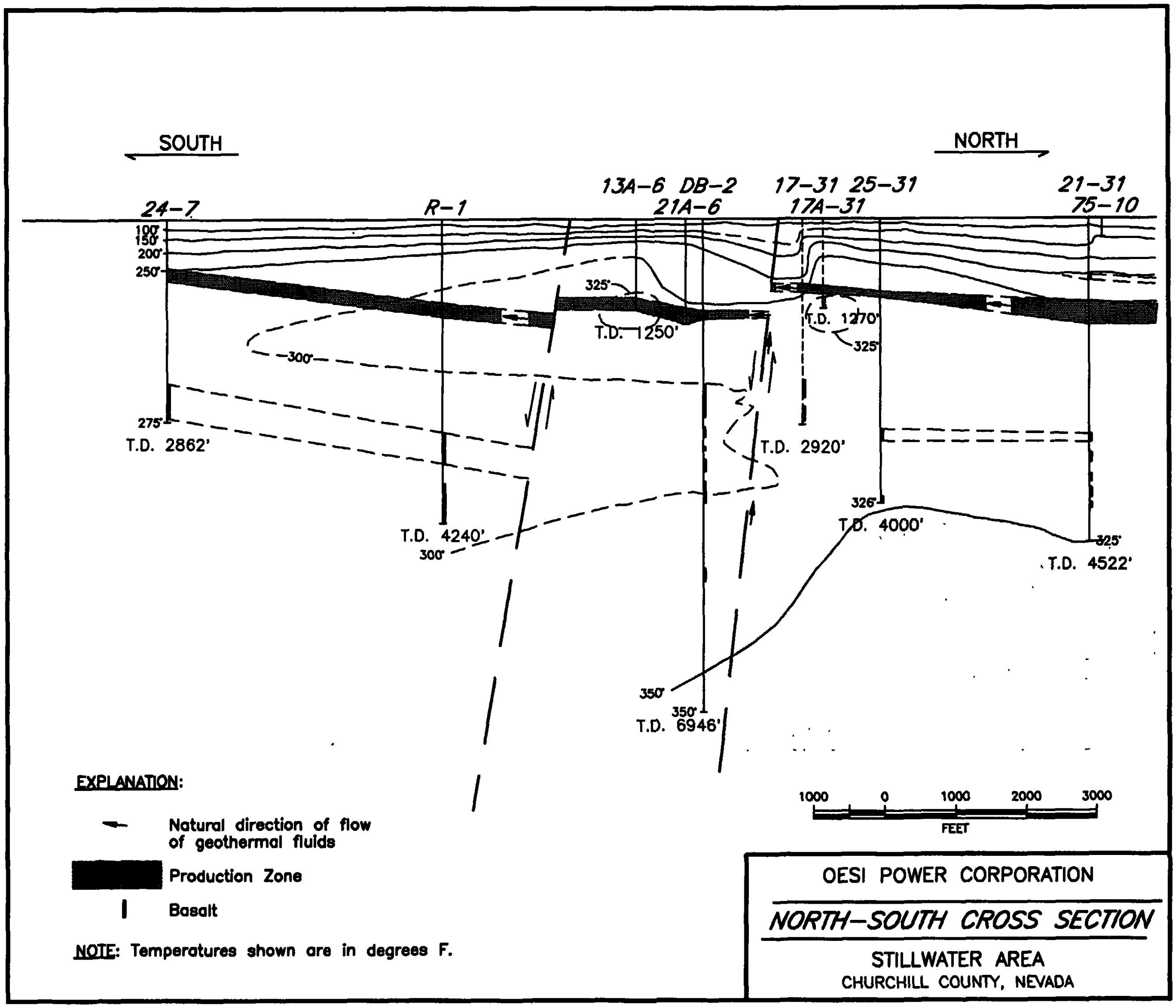


Figure 2. Cross section through Stillwater geothermal field.

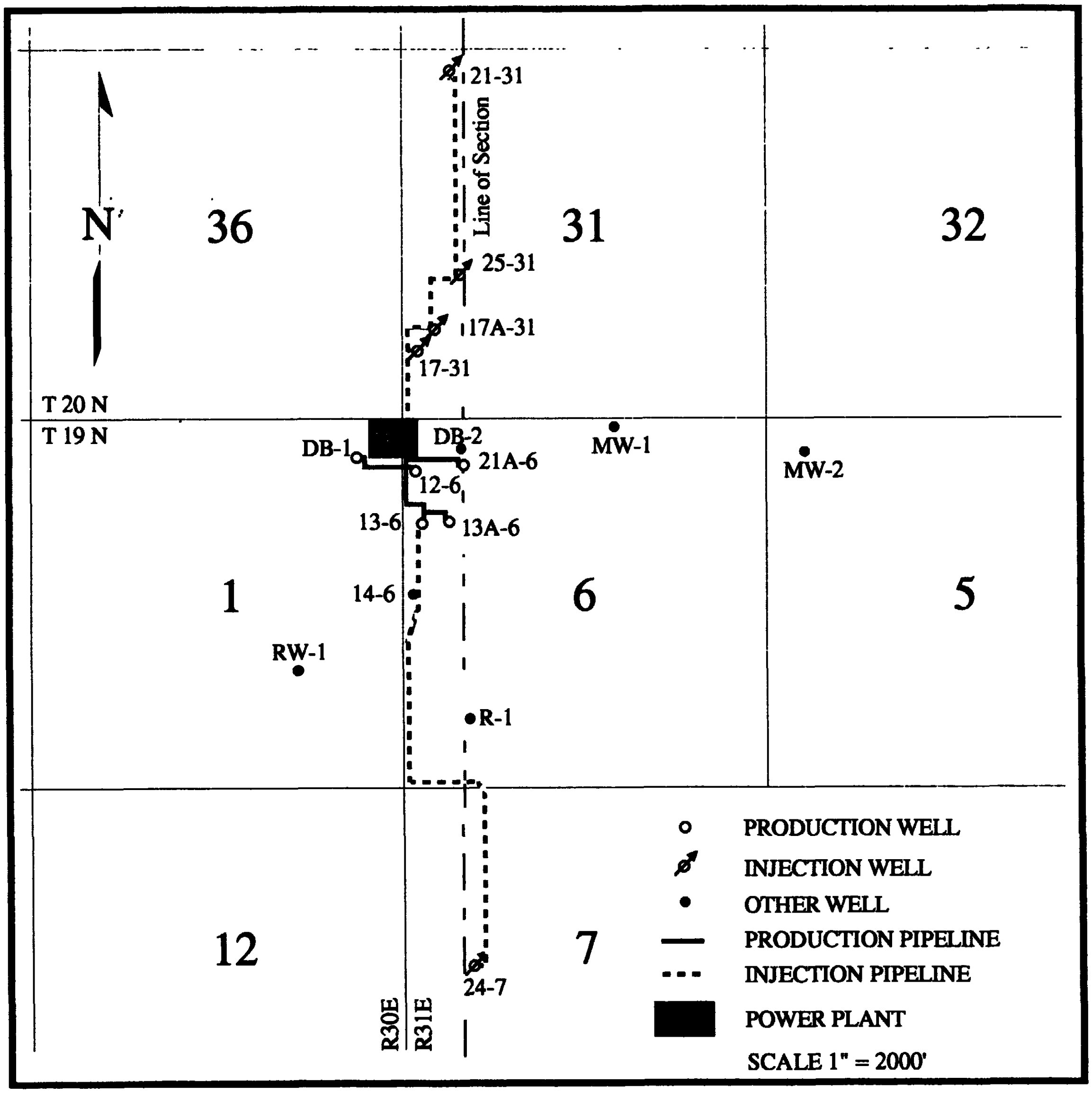


Figure 3: Stillwater Well Layout After Remediation

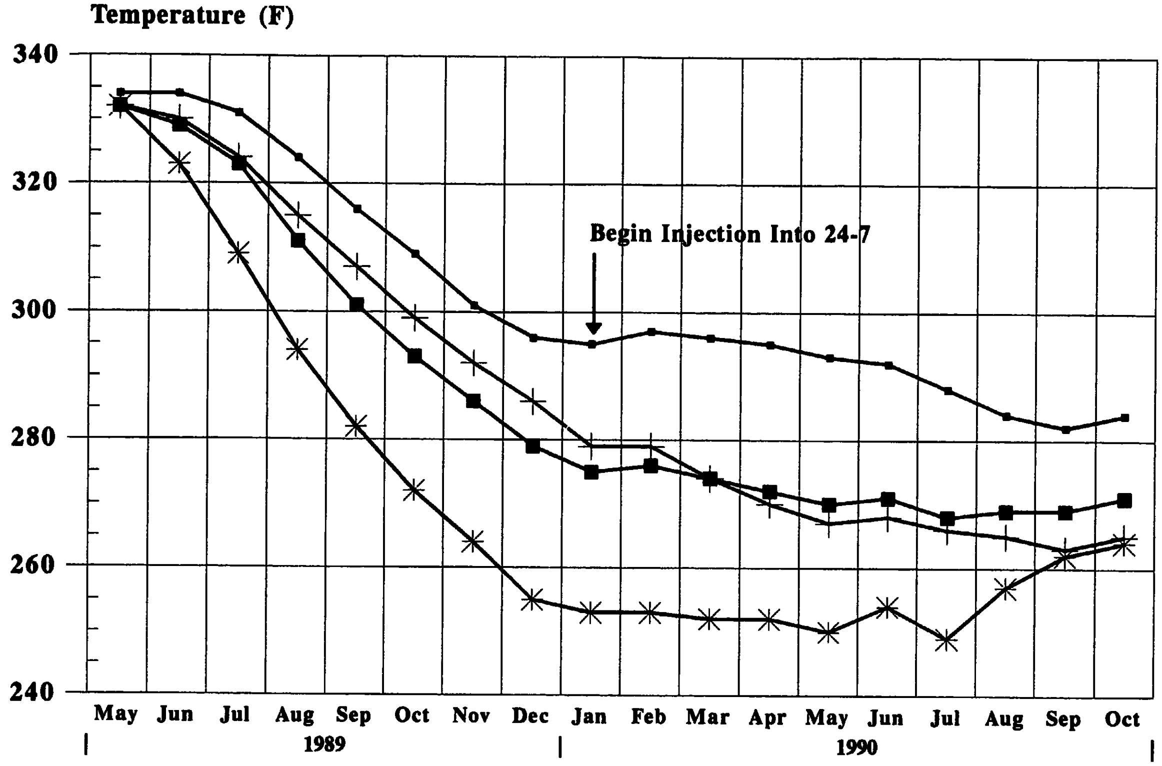
17-31 well was one of the original injection wells which was used to inject spent brine into the Production Sand but recompleted in 1991 to inject into the deeper fractured basalt unit. These two wells, 17-31 and DB-1, operate as a doublet system, with injection into one and production from the other. Well 17-31 is currently used as an injection well but the operation of the doublet could conceivably be reversed.

REMEDIATION

In the 1989 well configuration there were four production wells (12-6, 13-6, 13A-6 and 21A-6) and three injection wells (DB-1, 17-31 and 17A-31) (Fig. 1). Almost immediately after production began in April 1989, cooling of the production fluid from 12-6 began (Fig. 4). This well was only used about 20 days before its use was suspended due to the temperature decline of the produced brine. Cooling of well 13A-6 also began immediately (Fig. 4) but the cooling was not as severe as that in well 12-6. Cooling of well 21A-6 began immediately and suffered the greatest decline in temperature of all the production wells. The last well to experience temperature decline (about two months after the production began) was well 13-6 and it also suffered the least decline in temperature.

The distances between the initial injection and production wells ranged from 900 feet (DB-1 to 12-6) to 2,700 feet (17A-31 to 13A-6) (Fig. 1). Since all four of the production wells are in an area about 600 by 1,000 feet they were all relatively close to the injection wells. All of the initial production wells and injection wells were within an area of 1,500 by 2,700 feet.

In the first effort to reverse the cooling trend injection well 24-7 was drilled in late 1989 about 1 1/4 miles south of the production wells (for location see Fig. 3). This well was placed in ser-



13-6	334	334	331	324	316	309	301	296	295	297	296	295	293	292	288	284	282	284
13A-6	332	330	324	315	307	299	292	286	279	279	274	270	267	268	266	265	263	265
21A-6	332	323	309	294	282	272	264	255	253	253	252	252	250	254	249	257	262	264
Average	332	329	323	311	301	293	286	279	275	276	274	272	270	271	268	269	269	271

Figure 4: Stillwater Temperature Decline

vice in January 1990 with an injection rate of 2,200 gpm. Injection into this well more or less stopped the cooling trend, but did not reverse it (Fig. 4). Within a few months after well 24-7 was placed in service a nearly steady-state condition developed within the system and the inlet temperature to the power plant remained fairly steady at about 270°F until the remediation efforts were performed.

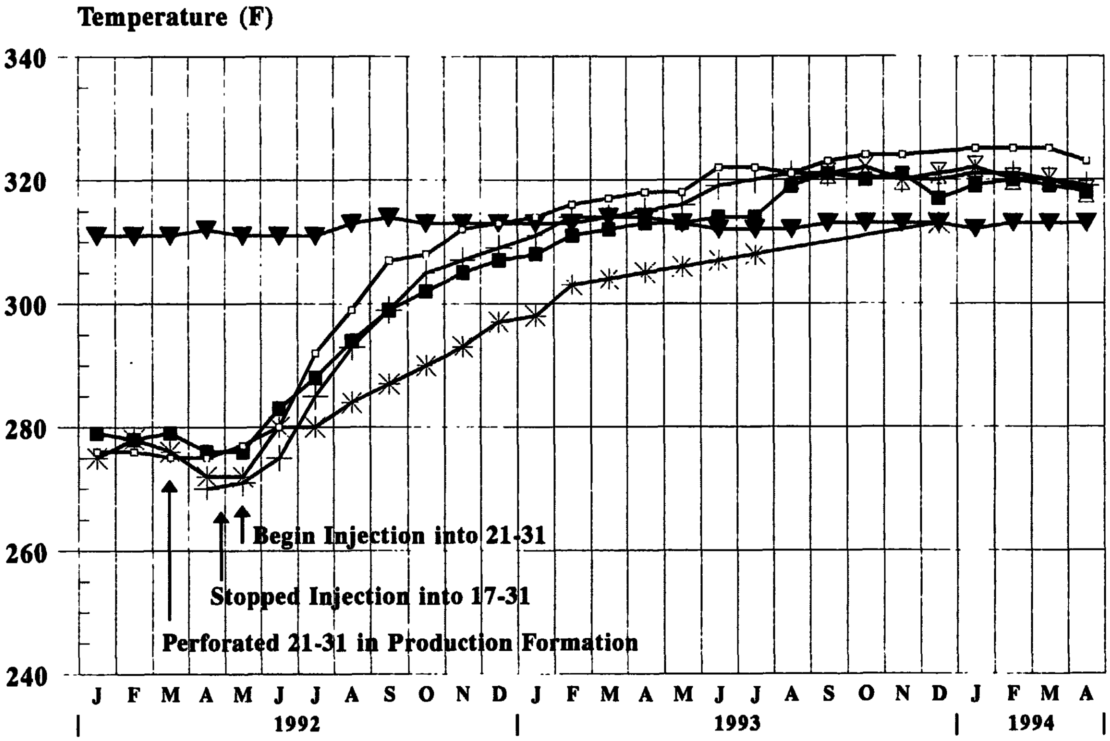
In 1991 a team consisting of a geologist, a petroleum engineer and a geochemist reviewed the geological data, reservoir test results, well drilling records, production-temperature data and other resource-related information. The resulting geothermal resource model provided insight as to new possibilities for resource optimization. The overall resource understanding was significantly different from the resource concept used during the original field development. The post-assessment resource model provided details of a multizoned, highly heterogeneous, geologically complex, hydrothermal system that had a high degree of temperature and permeability variation.

To increase the chances that the chosen remediation plan would be successful many varied studies were performed to evaluate the effects of different remediation options. Several analytical temperature and pressure models were developed to simulate the measured changes witnessed in the resource.

The implementation of the conclusions was problematic because, although disposal of spent geothermal brine was the clear solution to the cooling problem, a method of disposal was not obvious with the relatively low permeability of the Production Sand away from the area of the production wells. Attempts were made to inject into the basalt units near the north-south trending fault passing through the field in wells 21-31 and 25-31 but those attempts proved fruitless as sufficient permeability in the basalt was found only in two wells, 17-31 and DB-1 (Fig. 2).

The developed portion of the Stillwater hydrothermal system is recharged, both vertically and horizontally. Evidence for some vertical recharge to the area of the production wells is evidenced by the temperature recovery of well 12-6 to 341°F in a temperature survey run on January 28, 1993. This temperature is higher than the temperature in any of the surrounding wells. Well 12-6 was reequipped for production and is again in use as a production well, although the production temperature is about 316°F. The low production temperature is due to insufficient recharge of higher temperature brine to the well.

Pressure and temperature models confirmed that changing the injection strategy to inject at a greater distance from the production wells would provide the needed production flow rates without too much pressure drawdown in the production zone. This



	J 92	F	M	A	M	J	J	A	S	O	N	D	J 93	F	M	A	M	J	J	A	S	O	N	D	J 94	F	M	A
13-6	276	276	275	275	277	280	292	299	307	308	312	313	314	316	317	318	318	322	322	321	323	324	324		325	325	325	323
13A-6				270	271	275	285	293	299	305	307	309	311	314	314	315	316	319	320	321	321		320	320	321	321	320	319
21A-6	275	278	276	272	272	280	280	284	287	290	293	297	298	303	304	305	306	307	308					313				
Plant	279	278	279	276	276	283	288	294	299	302	305	307	308	311	312	313	313	314	314	319	321	320	321	317	319	320	319	318
12-6																				320	321	322	320	321	322	320	320	318
DB-1	311	311	311	312	311	311	311	313	314	313	313	313	313	313	314	314	313	312	312	312	313	313	313	313	312	313	313	313

Figure 5: Stillwater Temperature Recovery

also would be both commercially possible and beneficial to temperature recovery. All calculations showed that the more injectate being disposed away from the production wells the faster the temperature recovery would be and the greater the ultimate temperature recovery.

Evaluation of the flow within the Production Sand indicated that the flow paths in the fractures between the production and injection wells would extract only a minuscule percentage of the heat in the entire productive zone. The fractured volume of the Production Sand in the area of the production and injection wells was so small that almost any amount of injection into it resulted in rapid and continuous cooling of the produced brine.

In 1991, injection well 21-31 (Fig. 3) was drilled and completed about one mile north of the production wells to inject the spent brine away from the production area and to inject deep near the center of the thermal anomaly. The intent was to inject into a Tertiary basalt unit, if possible, because there was concern that injection into the Production Sand could result in the return of the injectate to the production wells within a matter of months. Those fears have since been shown to have been unfounded since there has not been any confirmed cooling of the production wells in over three years of injection into the Production Sand in well 21-31.

Well 21-31 was drilled in August 1991, but was not placed in continuous service until May 1992. In early 1992, attempts were made to inject into basalt units deeper than the Production Sand using a diesel-powered pump on a temporary basis for testing. When those efforts were unsuccessful because of the low permeability of the basalt units the casing was perforated in March 1992 to allow injection into the Production Sand at a depth of 1,200 to 1,400 feet. Shortly after that a permanent pump station was installed. At about the same time as well 21-31 started being used for injection, well 17-31 was reworked to inject brine into the basalt units at a depth of 2,350 feet.

Well DB-1, which is somewhat of an enigma, had been an injection well since plant start-up. It was changed over to a production well and now produces 800 to 1,000 gpm from a fractured basalt unit at a depth of 2,360 feet with a constant temperature between 312°F and 313°F without pumping (Fig. 5). However, pressure support is required for continuous commercial production. The well receives pressure support from injection of about 1,200 gpm into well 17-31 about 1,800 feet to the northeast, but has not been cooled by any injectate. The permeable portion of the basalt is bounded and is limited in size. Only small quantities of brine can be produced from, or injected into, the basalt unit without a doublet well system in operation.

In the current well configuration there are five production wells (three pumped, one standby and one free flowing) and three injection wells (Fig. 3). The pumped wells are unchanged from the original production plan and are 12-6, 13-6, 13A-6 and 21A-6, with 21A-6 being used when one of the other three wells is down for pump repair or replacement. The free-flowing well, DB-1, was originally an injection well. The injection wells being used are 24-7, 17-31 and 21-31, with about 2,700 gpm being injected into well 21-31, 2200 gpm into well 24-7 and 1,200 gpm into well 17-31.

Temperature recovery in the production wells was fairly rapid for the first few months after injection into well 21-31 began (Fig. 5). Injection began into well 21-31 on a test basis in January 1992 and was placed in full service in May 1992. By September 1992 the inlet temperature to the power plant had risen to 300°F from a low of 268°F. By the end of 1992 the inlet temperature had risen to 307°F At the end of 1993 the inlet temperature had risen another 10 degrees to 317°F and by April 1994 the inlet temperature had risen to 320°F. It appears that the temperature to the power plant has nearly reached its maximum recovery.

CONCLUSIONS

Cooling of production wells caused by thermal breakthrough of injectate from injection wells can be reversed in some situations, as has been demonstrated at Stillwater, Nevada.

In most geothermal systems attention must be paid to the variances from traditional, simplified reservoir/geologic models in order to efficiently and economically produce the resource over the life of a power-sales contract. Through the proper application of geological and engineering principles and experience a resource system can be defined in a manner sufficient to allow remediation.

By combining detailed engineering and geological analyses of available data gathered during the exploration, drilling and production phases of resource exploitation it was possible to hypothesize a reservoir model which, in addition to successfully indicating drilling targets, also was consistent with production history.

By taking advantage of the Stillwater system's heterogeneities a fluid distribution scheme was developed which balanced the need for system recharge with fluid disposal requirements. The limitations of adequate permeability was both a hindrance to successful exploitation and a means to the current solution.

It has been about three years since the configuration of production and injection wells at Stillwater was changed. The plant continues to operate with an inlet temperature 50°F higher than it was before the remediation program. However, this is 12°F short of the average initial temperature. It is likely that the production rate exceeds the vertical and horizontal recharge to the area of the production wells by a small amount and that cooler water is being drawn into the area of the production wells from the west and/or the east.

ACKNOWLEDGMENT

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