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A CASE HISTORY OF INJECTION THROUGH 1991 AT DIXIE VALLEY, NEVADA

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ABSTRACT

The Dixie Valley injection system has been operational for 3 1/4 years and disperses injectate into the reservoir through three distinct geological environments. Short-term step-rate injection tests underestimated the long-term injectivity of some of the injectors requiring additional injectors to be drilled. Liberal use of surface discharge over three years allowed orderly development of an eight-well injection system that provides pressure support for nine production wells but has not yet resulted in any cooling problems.

Tracer testing identified a single flow path while long-term chloride data have demonstrated injection returns to all production wells within one year. Present percentages of injectate recovered from production wells vary from as low as 18 to 100%. Calculated velocities of injectate through various portions of the reservoir range from minimums of 0.67' to 16.5' per hour.

INTRODUCTION

Return of large volumes of spent geothermal brine to the reservoir from which it was withdrawn can be of ultimate importance in extending the productive life of geothermal reservoirs and in most areas is an environmental must. Only in the past few years has the United States geothermal industry rapidly gained experience in this aspect of reservoir management and this is particularly true for fracture-type reservoirs. To date, little of the details of this fracture-type injection experience in the United States can be found in the geothermal literature. With injection rates of up to 9300 gpm the 62 MW (gross) Dixie Valley project may represent the largest volume geothermal injection experience into a localized and narrow fracture zone in the United States. It has now been operational for 3 1/4 years and 10.2 billion gallons of fluid has been returned to the reservoir (Orser and Stock, 1990).

EARLY INJECTION AND TRACER TESTING

During the late 1970's and early 1980's SUNEDCO drilled eight exploratory wells at Dixie Valley (Figure 1, Table 1). These widely-spaced wells ranged from good producers to basically cold or dry wells. By early 1982 the project had enough potential that an injection/tracer test was performed in the southern part of the field. Well 65-18 was utilized for injection and tracer testing purposes during a flow test of wells SWL-1, SWL-3, and 84-7. The maximum daily average injection rate was 1047 gpm and the total volume injected over 35 days was 31.6 x 10^6 gallons. Well 65-18 partially bridged either during or before this test and little valid injectivity data were obtained. A tracer test was also performed utilizing 70 pounds of sulfur hexaflouride. No tracer returned.

DIXIE VALLEY WELL LOCATIONS

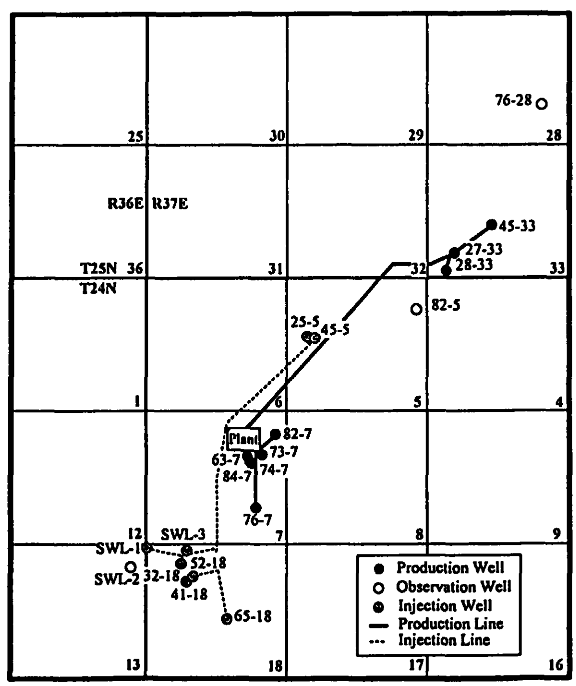

Figure 1

TABLE 1
DIXIE VALLEY INJECTION WELL DATA SUMMARY

Well	Date	Service Date	Total Depth	Injection Depth	Initial Static Injection Zone Temperature	Geological Environment	Casing or Tieback	Liner	Completion
SWL-1	1978	May-89	7255'	7191-7255'	428 F	Basalt Aquifer	9 5/8"	7"	open
SWL-3	1979	Aug-89	9126'	7325-7350'	428 F	Basalt Aquifer	9 5/8"	9 5/8"	perforated
52-18	1980	Sep-88	9860'	8900-9289 ?	445 F	Deep Fault	9 5/8"	7"	open
65-18	1981	Sep-88	9466'	9265-9350'	437 F	Deep Fault	9 5/8"	7"	slotted
45-5	1981	Sep-88	8261'	5828-6155'	401 F	Shallow Fault	9 5/8"	7"	perforated
32-18	1986	Sep-88	7461'	7360-7374'	427 F	Basalt Aquifer	13 3/8"	9 5/8"	open
25-5	1989	Sep-89	6215'	6140'	402 F	Shallow Fault	13 3/8"	none	open
41-18	1990	Jan-91	10739'	9635'-?	unknown	Deep Fault	13 3/8"	9 5/8"	open

RESERVOIR ASSESSMENT

In 1985 Oxbow Geothermal Corp. acquired the Dixie Valley steamfield and began a major drilling, reworking, and reservoir testing program. Drilling was performed with the aim of verifying production capacity equal to about 60 MW. None of this drilling activity was directed toward injection objectives.

A primary reservoir assessment conclusion was that injection would be important in minimizing the reservoir pressure drawdown. Until this time, injection back into the narrow and linear reservoir had been viewed with trepidation as to potential cooling. With the assurance of short-term reservoir pressure maintenance problems (assuming no injection), potential longer-term cooling problems became of secondary concern. In hindsight, this realization marked the beginning of the Dixie Valley injection program.

Serious cooling concerns remained so a plan for gradually increasing injection into a variety of geological environments was prepared. This plan involved extensive utilization of surface discharge for three years as tracer testing and additional drilling, if needed, was performed. Oxbow then began the process of permitting and evaluating several productive but lower enthalpy wells as injectors. A generalized plan and schedule for reaching full and continuous injection by early 1991 was developed and permitting for full surface discharge for up to three years was begun.

SIX-WELL FLOW TEST

In the summer of 1986 a six-well flow test was performed to truly test the reservoir under actual operational conditions. In 73 days 866 million gallons of fluid were removed from the reservoir and flowed into the highly saline Humboldt Salt Marsh (Desormier, 1987). Production and observation wells were scattered throughout the field and selected so that a maximum understanding of the reservoir would be the result.

The modeling results from the six-well test were startling in that the predicted reservoir pressure declines over the projected 30 year life of the power plant were substantially greater than predictions made from earlier, lower-volume flow tests. These predictions left no doubt that a successful program of injection back into the reservoir was crucial to the long-term viability of the project. Consequently, the injection program was accelerated so that a more or less complete injection system would be available at plant startup.

GEOLOGICAL MODEL

The reservoir assessment and six-well test produced a generalized geological model of the reservoir (Figure 2). The most productive part of the reservoir consists of a narrow zone of fracturing associated with the range-front fault defining the eastern limit of the

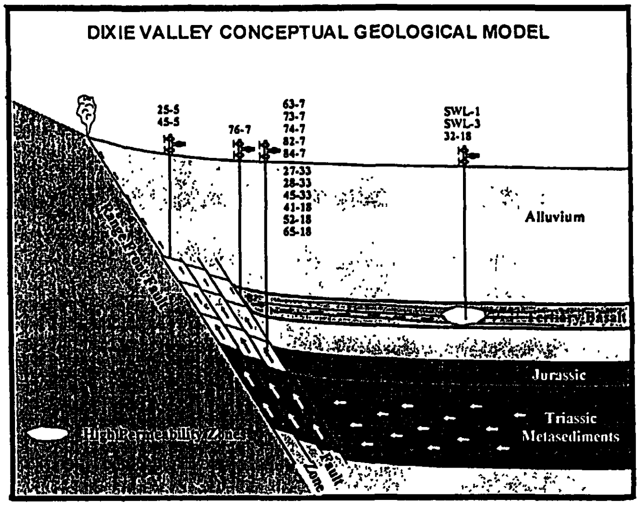

Figure 2

Stillwater range. One major subhorizontal aquifer extends east of the range-front fault within Miocene basalts between depths of 7000 and 8000'. Fluid with a temperature of 480 °F rises up the fault cooling above depths of 8500 to 10,000'. Some fluid enters the basalt aquifer and flows away from the fault. Temperatures also vary along the strike of the fault.

The six-well flow test confirmed that the lower-enthalpy wells in section 18 were unlikely to be suitable for long-term production. It was fortuitous that these low-enthalpy wells coincided with a potential injection philosophy of dispersing injectate into the reservoir through a variety of geological environments. A tentative plan for injecting into the basalt aquifer, the range-front fault at shallow depths near 6000', and relatively cool portions of the fault at depths of 9000 to 10,000' utilizing existing wells was refined.

INJECTION TESTING

During 1987 four candidate injection wells were identified and prepared for step-rate injection testing. Prior to testing, the wellbores were cooled with cold water at rates of 100 to 200 gpm for one to three days to minimize transients. The volume of cooling water usually far exceeded the amount pumped during the actual tests. The volume of water storage available for high-rate pumping was the limiting factor for all tests and ranged from 76,000 gallons to 492,000 gallons. Maximum pump rates varied between 1000 and 2550 gpm. The tests typically lasted from four to five hours so only short-term responses to high-volume injection rates could be measured.

Injection capacity into wells 45-5, 65-18, 52-18, and 32-18 was interpreted to total 8300 gpm at a wellhead pressure of 100 psi. This exceeded the initial design capacity of 6000 gpm by 38%. Also wells SWL-1 and SWL-3 were available for injection.

PLANT STARTUP AND TRACER TESTING

In early July 1988 the power plant commenced continuous operation and in September the injection system became operational. Shortly thereafter, the actual sustainable capacity of 4000 to 5000 gpm was far below the expected 8300 gpm (Figure 3).

Well 65-18 had wellbore stability problems, even after a slotted liner was installed. Instead of accepting the predicted 1350 gpm the actual sustainable rate was much closer to 600 gpm (Figure 4). The stability problem became apparent only while injecting. Well 32-18 was behaving as if it were completed in a relatively small volume pocket that would accept fluid willingly at rates up to 2000 to 3000 gpm for only a few hours to days. Then it would quickly reduce to 1000 to 1200 gpm for the long-term (Figure 5). Well 45-5 was accepting about 1600 gpm (Figure 6) which was relatively close to the expected 2000 gpm. Only well 52-18 exceeded its predicted injection rate of 1100 gpm by a mere 100 gpm (Figure 4). Additional capacity was required but tracer testing of the three geological environments needed to be performed before additional injectors would be placed in service.

The tracers were injected as 300 bbl slugs into wells 45-5, 52-18, and 32-18 in latest 1988 and early 1989 (Adams et al. 1989). The only returns were to well 76-7 of tracer injected into well 32-18. The flow path between 32-18 and 76-7 was obviously through the basalt aquifer. The initial return time was 9.3 days and the peak was at 33 days. This was in reasonable agreement with the numerical model which predicted a peak at 11 days. With these encouraging results in hand, and no evidence of any cooling of well 76-7, it was believed that additional injection into any of the three environments would not result in short-term cooling.

INJECTION RATE TOTALS

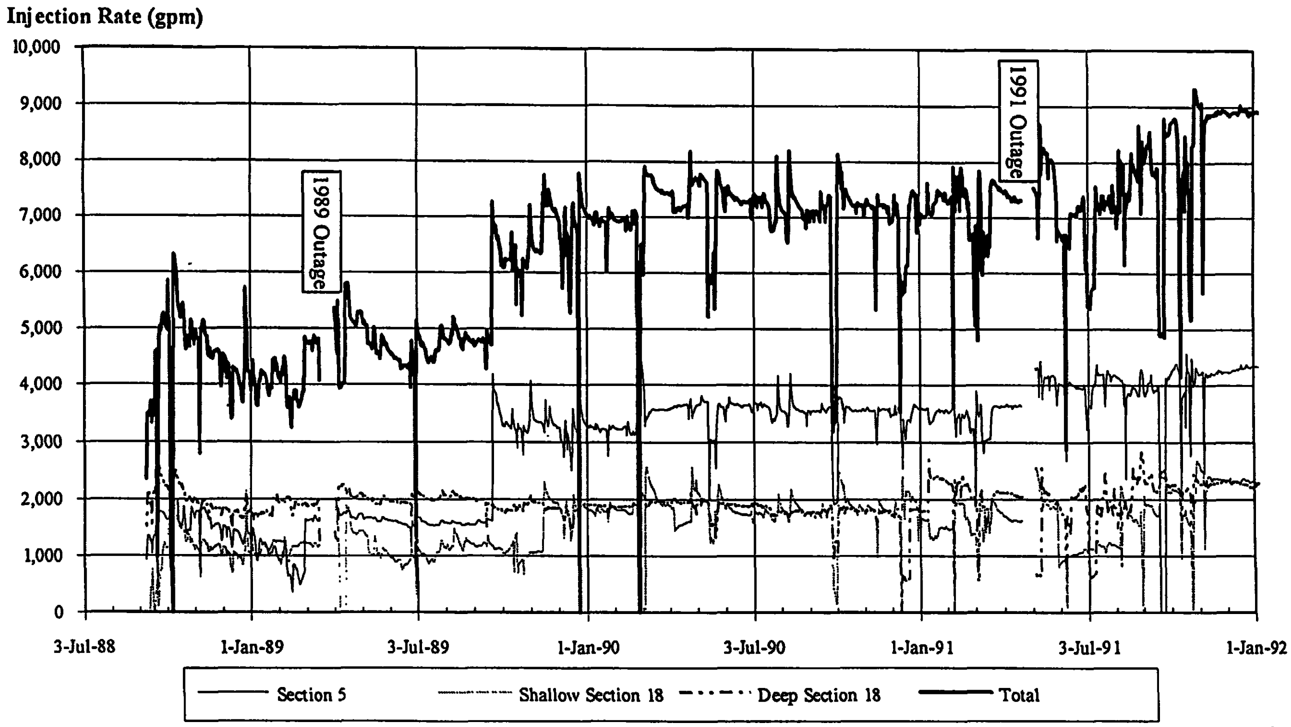

Figure 3

INJECTION RATES - DEEP SECTION 18

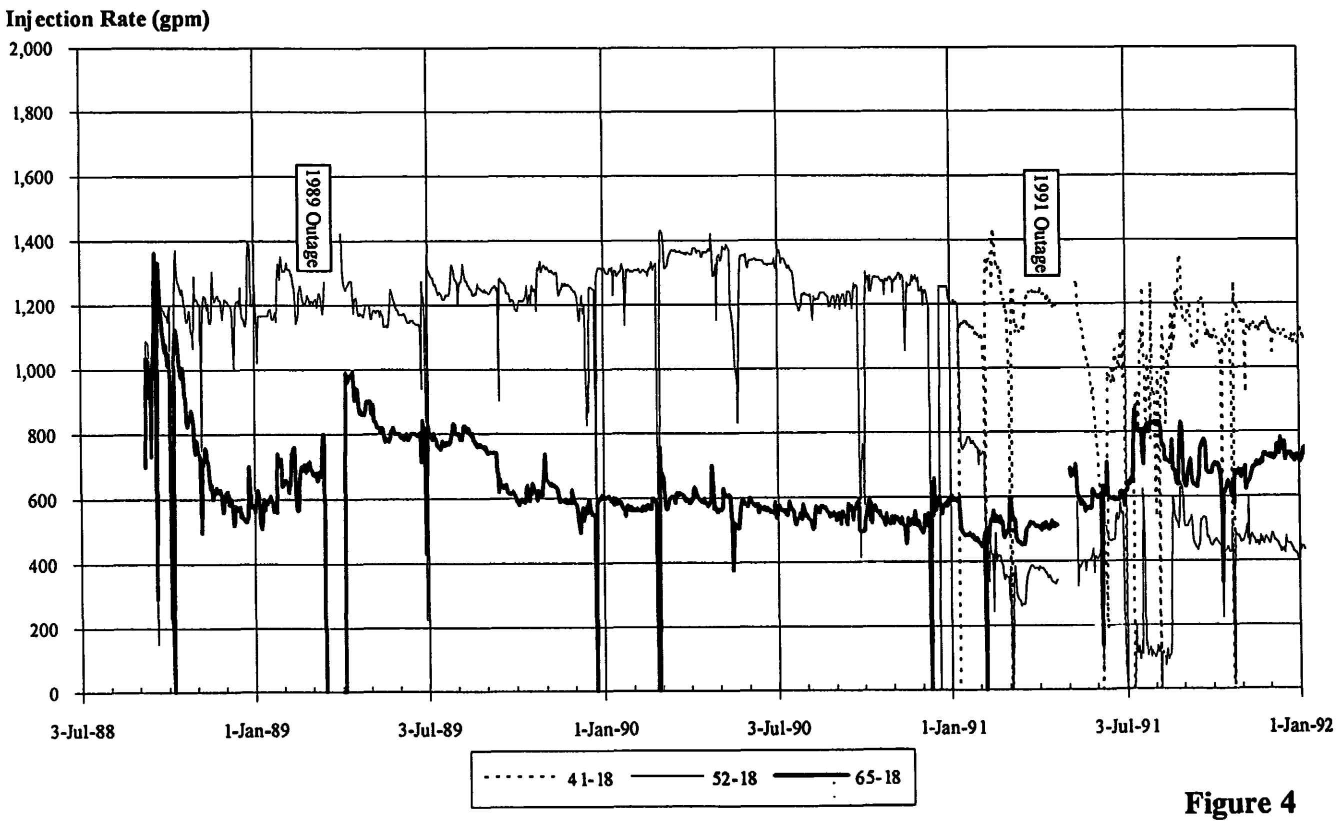

Figure 4

INJECTION RATES - SHALLOW SECTION 18

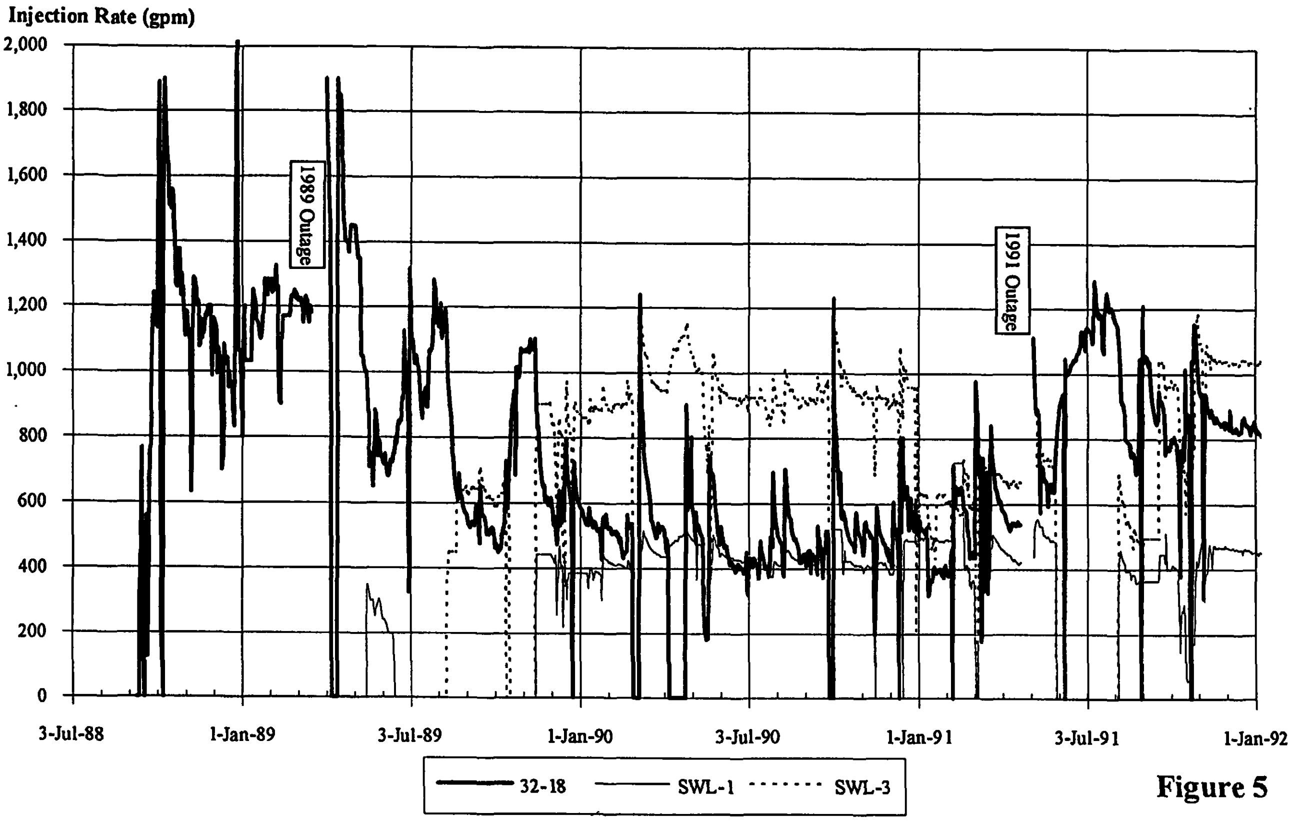

Figure 5

INJECTION RATES SECTION 5

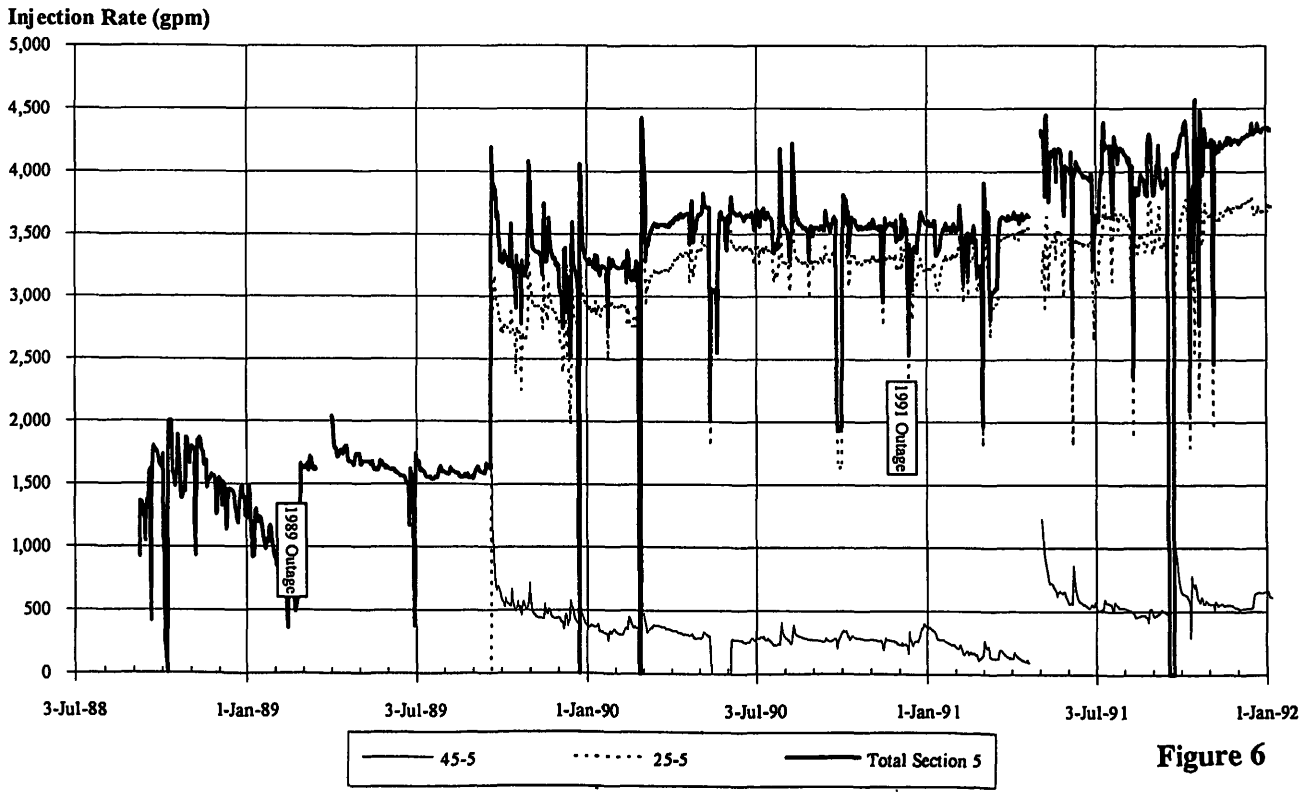

Figure 6

WELL 25-5

In mid 1989 wells SWL-1 and SWL-3 were attached to the injection system and injection into the basalt aquifer was increased by a modest net 600 gpm. The 32-18 injection rate decreased by 600 to 800 gpm due to interference (Figure 5). This demonstrated that additional local injection into the basalt aquifer would likely result in high interference with the three existing injectors and little net gain. A second possibility was to drill into the basalt aquifer some distance away from the existing injectors but this option entailed a significant degree of low permeability risk and was not pursued. Total capacity with SWL-1 and SWL-3 was now 4800 gpm, still significantly short of an increased injection goal of 8500 gpm which did not include 500 gpm of cooling tower overflow being surface discharged. The increase resulted from two new production wells.

As well 45-5 was performing up to expectations, a pressure fall-off test indicated high permeability, there was adequate injection line capacity to increase flow north from the power plant, and the expected drilling depth was a relatively shallow 6000', this site was selected as the first location in Dixie Valley drilled specifically for injection. Well 25-5 was drilled in mid 1989 and was a spectacular success for two reasons. First, excellent permeability was encountered. Second, well 25-5 was completed with larger casing than 45-5 (Table 1) and a 12 1/2" open hole which improved the wellbore hydraulics. By contrast, injection in well 45-5 is through perforations. Initially well 25-5 would accept 2900 gpm but this reduced the 45-5 injection rate from 1600 gpm to less than 500 gpm giving an initial net gain of 1700 to 1800 gpm (Figure 6).

The injection zone in well 25-5 is at the same depth as well 45-5, in the same Miocene basalt, and 390' southwest of 45-5. A 1.2 million gallon flow test was conducted and a series of chemical samples showed the fluid to be uncontaminated by injectate pumped into 45-5 for one year. Well 25-5 had the same fluid-entry temperature as 45-5 prior to the start of injection. Injectate from 45-5 had not laterally migrated to the immediate vicinity of 25-5 over a period of one year. The large interference between 25-5 and 45-5 is interpreted as evidence the basalt in the shallow range-front area in section 5 also behaves as a high permeability pocket, albeit with almost double the long-term injectivity of the basalt pocket in section 18.

Well 25-5 did not complete the Dixie Valley injection program as by mid 1990 a third additional production well had been drilled and the total volume of spent brine was up to about 9000 gpm, while the total injection capacity was now 7200 gpm. There also remained the 500 gpm of cooling tower overflow.

WELL 41-18

To overcome the injection shortfall of 2300 gpm, the injection lines were pigged to remove a rough scale and wells were cycled to attempt to increase capacity but these actions only resulted in a few hundred gpm of improvement. Increased pumping power was analyzed but found to be uneconomic compared to drilling another injector. As the basalt pockets in sections 5 and 18 were now believed to be saturated, the only conservative option remaining was to drill another deep relatively expensive injector in section 18.

Well 41-18 was completed in latest 1990. The original hole, completed about 450' southwest of injection well 52-18, was impermeable. A successful redrill was completed 250' northeast of well 52-18. However, due to directional considerations the actual injection interval appears to be within 200' of the 52-18 injection interval and there is significant interference between 41-18 and 52-18. After 41-18 was placed in service, the combined total for the two wells stabilized at 1450 gpm giving a net increase of only 150 gpm. As was the case for the 25-5 and 45-5 pair, the newer well 41-18 accepts the majority of the fluid.

Serious attempts were made to flow 41-18 to obtain samples for chemical analysis and downhole temperature and pressure data but the well would not sustain flow. Logging tools could not be lowered below 8335' where the temperature was 160 °F lower than the preproduction static temperature in 52-18 at the same depth. This was after blowing the well for 13 hours and is interpreted as evidence that the 41-18 area has been significantly cooled by previous injection into 52-18.

After 41-18 was placed in service in January 1991 the total injection capacity was 7300 gpm which left a total shortfall of 2200 gpm and the surface discharge permit was nearing the end of its three year span.

1991 IMPROVEMENTS

The most obvious and economic method now available for increasing injectivity was to improve the efficiency of the existing injection system so wells 52-18, 65-18, and 25-5 were scraped during a plant outage to remove a soft aluminosilicate scale that had been continuously building up. No problems were encountered in 52-18 or 65-18. Well 25-5 was scraped but between depths of 3936 and 3970' unexpectedly hard reaming was required.

Following these workovers, the injection system showed unexpected changes in character. Most striking was the dramatic increase in 45-5 injection. Well 45-5 was not worked over. There was no increase in 25-5 injectivity. The net short-term improvement of the section 5 injectors was about 400 gpm but this has slowly increased to about 700 gpm. The section 18 basalt injectors showed a net increase of 700 gpm injectivity and well 65-18 showed a sustainable improvement of 200 gpm. The increased injectivity since the 1991 field shut down and workovers is 1600 gpm which increased the total rate to 8900 gpm.

The most recent improvement to the injection system was the addition of the cooling tower overflow in September, 1991. This 500 gpm jump does not show as a step on Figure 3 as there was much ongoing maintenance and repair activity involving the wellfield and injection system. Injection rates were highly variable.

In late October 1991 the injection system reached its all time high rate by disposing of approximately 9300 gpm. Since early November 1991 a sustainable injection rate of 8800 to 9000 gpm has been demonstrated. Pressures required to dispose of this volume seldom exceed 80 psig at the wellheads. Currently, with no liquid surface discharge, about 80% of the produced fluid is injected.

INJECTION IMPACTS ON THE RESERVOIR

The success of an injection program is defined by two parameters, pressure support for the producers combined with an absence of cooling of the producers. To date, there has been no indication that any of the production wells have cooled. Flowing downhole temperature surveys are obtained annually in a few representative wells. Well 76-7, the most likely to have cooled, has been surveyed annually and as of April 1991 there has been no discernable temperature decline. Due to the short tracer return time to 76-7 cooling is expected. The rate of cooling will be the most important factor.

Pressure support of the reservoir is most easily determined by analyzing the long-term pressure changes in production and observation wells. With the hang-down strings in the Dixie Valley production wells for scale inhibition purposes, downhole pressure data are rarely obtained but the rate of pressure decline during 1991 appears to have been very low as productivity curves showed little or no change and flash point depths remained constant. There are no high-permeability wells available for long-term pressure monitoring within the two main production areas.

Two relatively cool, remote, and impermeable wells, 76-28 and 62-21, have shown weak responses to production (Figure 7). The pressure changes in 62-21 are so small (12 psi total) and gradual that little can be said of its significance. It took four to five months after the start of production for the pressure change in 76-28 to be detectable. Between September 1988 and March 1990 the rate of pressure decline in 76-28 slowly increased. After March 1990 the pressure decline has been linear.

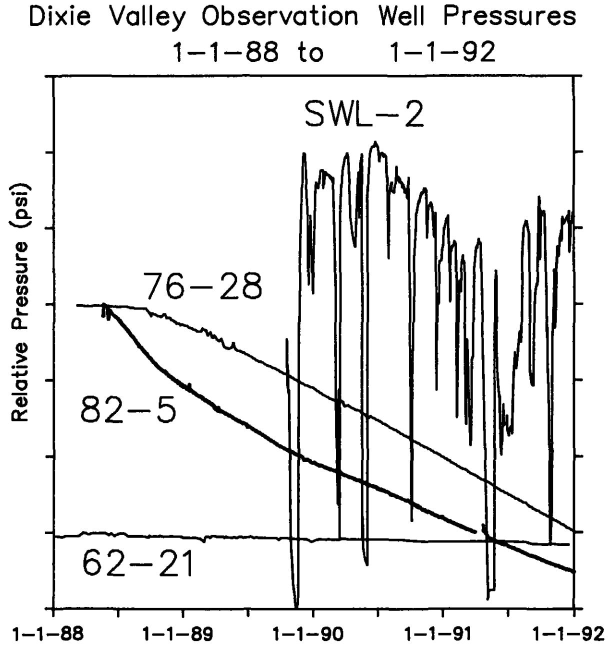

Figure 7

Pressures measured in observation well SWL-2 are dominated by pressure changes in the basalt aquifer in section 18, which in turn are dominated by the amount of injection in wells SWL-1, SWL-3 and 32-18. Very short term pressure changes of a few hundred psi are common.

The most informative observation well in the field is 82-5, a low-permeability well completed in the deep range-front fault environment a short distance southwest of the section 33 producers. The most striking difference between 82-5 and 76-28 is that the rate of pressure decline in 82-5 (which can be viewed as being generally within the reservoir) is declining while the rate in 76-28 (outside the reservoir) is remaining constant. Presumably the difference between the two responses represents either local recharge or pressure support from the injection program impacting well 82-5.

Inflection points in the 82-5 data can be correlated with changes in the northern part of the field. Injection began in September 1988 and the first major inflection, a major decline in rate, occurs three months later in early December 1988. In September 1989 injector 25-5 was placed in continuous service and four months later in January 1990 there is another large decrease in the rate. Producer 28-33 was placed in service in mid July 1991 and in early October the rate of pressure decline in 25-5 increased, a lag of 2 1/2 months. Thus observation well 82-5 is responsive to both production and injection changes with time lags of 2 1/2 to four months.

One other inflection in the 82-5 data is also striking and perplexing. In April 1991 there was a two week field shutin for plant maintenance and the pressure showed a short-term increase. This is the only apparent short term fluctuation ever noted in well 82-5. No similar increase was detected during the spring 1989 outage.

Since 1988 the pressure decline rate in 82-5 has decreased by 62 percent even though the average amount of power generated has increased by 19%.

CHLORIDE CONTENTS

The flash process concentrates conservative elements in the spent brine prior to injection. Chloride in particular, has been utilized as a long-term tracer.

Separator V-101 and associated section 33 wells showed no measurable increase in chloride until April or June 1989, 6 to 8 months after injection began (Figure 8). The initial increase in chloride was so slight that it was not recognized until many months later due to the data scatter. Since mid 1989 the rise in chloride content has been linear. By late 1991 the chloride content had increased to 350 ppm from 250 ppm. Assuming that the fluid produced by V-101 late in 1991 is a simple mixture of the original V-101 reservoir fluid (1988 composition) and the initial injectate composition in 1988, then V-101 is currently producing a maximum of 68 to 79% recycled injectate (Table 2). However, if the most recent injectate components with chlorides as high as 439 ppm are assumed then the minimum calculated fraction of injectate declines as low as 53%.

The three V-102 wells show a more diverse chemistry than the V-101 wells. Well 84-7 has shown less increase in chloride than 74-7 or 63-7 and this increase has occurred much later. The chloride content in wells 74-7 and 63-7 have increased from 300 ppm to about 360 ppm. Assuming a mixture of initial V-102 reservoir fluid and initial injectate composition the 74-7 and 63-7 fluids at the end of 1991 contained a maximum of 68 to 76 % recycled injectate while 84-7 contains 35 %. This is a major variance for wells located so close together. The most significant difference between these three wells is that the producing interval in 84-7 is several hundred feet shallower than in 63-7 or 74-7.

The two V-105 wells are also distinctive. Currently well 73-7 is producing between 23 and 32% recycled injectate. Initially 82-7 produced a fluid similar to the other deep section 7 wells but over late 1989 it shifted composition to a chemistry midway between deep section 7 and section 33. Since mid 1990 the chloride content of 82-7 has been increasing. This history makes selection of the original chloride content somewhat ambiguous. If it is assumed that the minimal chloride content of 282 ppm represents the reservoir fluid entering the wellbore then the percentage of recycled injectate produced by 82-7 is between 18 and 24 %, the lowest of all the production wells.

Well 76-7 has undergone the greatest injectate impact. In slightly less than two years the 76-7 chloride content equaled the initial injectate values. Between mid 1989 and mid 1990 well 76-7 became the only well to undergo a decline in silica content from about 485 to perhaps 450 ppm. The 76-7 fluid currently produced is basically 100% recycled injectate.

INJECTION FLOW PATHS AND VELOCITIES

The tracer testing documented only one injection flow path, from injection well 32-18 through the basalt aquifer to well 76-7. The first molecules of tracer to return had to travel at a minimum speed of 16.5 ft/hr and the speed of the tracer peak was at least 4.7 ft/hr. In the 3 1/4 years since the injection system became operational it is possible that a few molecules have made the roundtrip from 32-18 to 76-7 on the order of 120 times if the breakthrough time is utilized. If the more average peak returrn time is used some fluid has

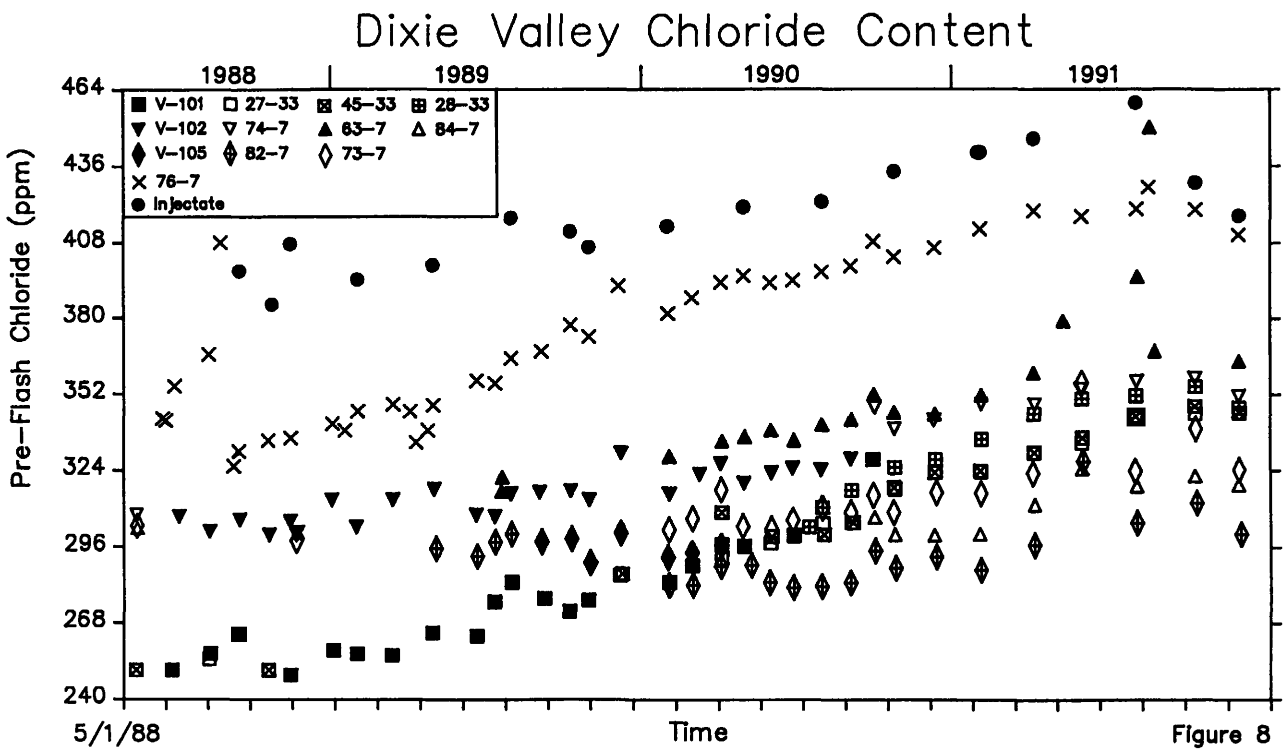

Figure 8

TABLE 2
CALCULATED PERCENTAGE OF INJECTATE RETURNING TO DIXIE VALLEY PRODUCTION WELLS

Well	Initial Preflash Cl Content (ppm)	Recent Cl Content (Feb 92) (ppm)	Initial Injectate Cl Content (ppm)	Recent Injectate Cl Content (ppm)	Current % Injectate Max	Current % Injectate Min
45-33	252	354	397	439	70.3	54.5
27-33	252	351	397	439	68.3	52.9
28-33	252*	366	397	439	78.6	60.9
82-7	282*	310	397	439	24.3	17.8
73-7	295	328	397	439	32.2	22.9
63-7	295*	373	397	439	76.4	54.1
84-7	295	331	397	439	35.2	25
74-7	295	364	397	439	67.6	47.9
76-7	308	412	397	439	116.8	79.4

* assumed

made on the order of 35 passes through the basalt aquifer. These velocities and estimated maximum numbers of round trips are probably low due to the fact that injection rates into the basalt aquifer have doubled since the tracer test.

The chloride data provide evidence for longer flow paths at greater depths. The southern deep production wells in section 7, 63-7, and 74-7, have undergone the largest increases in chloride. These wells are also closest to the deep section 18 injectors. It is logical to believe that 63-7 and 74-7 are preferentially intercepting injectate moving north from section 18. V-102 chloride values began to increase 200 to 300 days after injection commenced. The closest existing deep injector to 74-7 was 52-18, about 4000 ft away. Dividing 4000 ft by the average of 250 days indicates the injectate moved on the order of .67 ft/hour. It is not surprising that no tracer returns were recovered from well 52-18. Currently the amount of injectate delivered deep into section 18 is only a few percent higher than during the tracer test so the calculated velocity of .67 ft/hr probably remains valid.

At the north end of the field, the majority of the injectate from wells 25-5 and 45-5 is moving northward to the section 33 wells. Evidence for this comes from the southernmost production well 28-33 which was completed in mid 1990. The initial composition of 28-33 was very similar to the then-existing chemistry from wells 27-33 and 45-33 and much different from the initial chemistry of 27-33 and 45-33. The initial fluid in the vicinity of 28-33 had already been replaced by injectate prior to the completion of 28-33. Also, since 1990 well 28-33 has consistently had a slightly higher chloride content that 27-33 or 45-33.

It took about 200 days for the V-101 chloride contents to begin increasing after injection into 45-5 commenced. If it is assumed that the injectate from 45-5 flows directly down the fault to a depth of 9500 ft and then laterally to the V-101 wells this distance is 9500 ft. This gives an injectate velocity of about 1.9 ft/day which is almost 3 times the velocity calculated between 52-18 and 74-7. Since 25-5 was completed this velocity has increased.

It is unclear as to whether the relatively modest injectate component in wells 82-7 and 73-7 is coming from section 18 or section 5 injectors.

CONCLUSIONS

To date, the geothermal injection program at Dixie Valley has been one of the most successful large volume programs into fractures in the world. Initial predictions of injection capacity based on short-term tests were significantly higher than long-term sustainable rates. This, coupled with the fact that the field has been operated at rates about 20% higher than initially intended, resulted in the need to hookup four additional wells to the injection system. Injection is currently a routine operation into 8 wells at sustainable rates of 9000 gpm. Long-term injection rates into individual wells vary from 400 gpm to 3700 gpm. The initial concept of dispersing injectate into three differing geological environments has proven effective. However, certain injectors with less than 500 feet of separation from neighboring injectors are subject to large interference effects in all three environments.

Tracer testing and routine field chemistry monitoring have documented that all Dixie Valley production wells are producing significant amounts of recycled injectate. The minimum amount of injectate is being produced by well 82-7, between 18 and 24 %, while at the other extreme well 76-7 has been producing more or less pure injectate. Estimated minimum velocities of the injectate in varying parts of the reservoir ranged from about 0.7 ft/hr to over 16.5 ft/hr in 1988. With greater volumes of fluid now being injected these minimum velocities must have increased.

Downhole pressure data from dry hole 82-5 indicate that at least the northern part of the field is seeing good pressure support from injection into section 5. Injectate from the section 5 injectors appears to be primarily moving northeast to reappear in the section 33 producers. Injectate, at both shallow and deep levels, from section 18 migrates northward to reappear in the section 7 producers.

No detectable cooling of any of the 9 production wells has occurred as of spring 1991 or after 2 1/4 years of injection. This is in spite of evidence which indicates injectate can be recycled through well 76-7 in as little as 9.3 days. If well 76-7 shows no cooling with this rapid return time, it is expected that all other wells which have return times in excess of 200 days are unlikely to experience cooling in a time period of less than decades.

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