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RESERVOIR RESPONSE TO INJECTION IN THE SOUTHEAST GEYSERS

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ABSTRACT

A 20 megawatt (MW) increase in steam flow potential resulted within 5 months of the start-up of new injection wells in the Southeast Geysers. Flow rate increases were observed in 25 wells offset to the injectors, C-11 and 956A-1. This increased flow rate was sustained during 9 months of continuous injection with no measurable decrease in offset well temperature until C-11 was shut in due to wellbore bridging. The responding steam wells are located in an area of reduced reservoir steam pressure known as the Low Pressure Area (LPA). The causes of the flow rate increases were twofold: (1) an increase in static reservoir pressure and (2) a decrease in interwell communication.

Thermodynamic and microseismic evidence suggests that most of the water is boiling near the injector and migrating to offset wells located "down" the static pressure gradient. However, wells showing the largest increase in steam flowrate are not located at the heart of the pressure sink. This indicates that localized fracture distribution controls the preferred path of fluid migration from the injection well. A decrease in noncondensible gas concentrations was also observed in certain wells producing injection-derived steam within the LPA.

The LPA project has proven that steam suppliers can work together and benefit economically from joint efforts with the goal of optimizing the use of heat from The Geysers' reservoir. The sharing of costs and information led directly to the success of the project and introduces a new era of increased cooperation at The Geysers.

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BACKGROUND

Water injection into The Geysers geothermal field first began in 1969 with the start-up of well SB-1 in the area of Pacific Gas and Electric (PG&E) Units 1-6. Since 1982, throughout The Geyser field, approximately 450 billion pounds of water or 28 percent of the mass of steam produced has been reinjected, with the remainder being evaporated in the power plant cooling process. Overall, injection has proven to be an environmentally safe method of disposing of the plant effluent since the injectate is contained in the reservoir and does not contaminate surface water (Crockett and Enedy, 1990). The steam field operators have experienced both positive and negative results with water injection (Barker and others, 1989). Experience shows that water injection can lessen the rate of steam-flow decline at The Geysers.

There are few examples in the literature of beneficial long-term reservoir response to injection at The Geysers, because of the often subtle or delayed effects of injection on offset steam well flowrate. However, through the use of advanced decline curve analysis techniques, decreased rates of steam-flow decline have been determined. For example, Ripperda and Bodvarsson (1987) found a slowing of the rate of steam decline on selected Geysers' wells "probably" due to injection which began in the "immediate vicinity" just prior to the change in flow behavior. In the southeast Geysers, Enedy (this volume, b) found lower flow rate declines on producers located offset to an injector which were in part attributable to "water injection support." In both studies, type curves were used to aid in the decline curve analysis.

Further evidence that water injection can supplement steam production is based on tracer tests. Deuterium and tritium are two tracers used at The Geysers to estimate the injection derived component of steam production and to track fluid movement across the reservoir. In a 1975 tritium tracer test in well SB-1, approximately 18 percent of the injected tritium was recovered from 20 offset steam wells, demonstrating that the injectate is boiling and being produced as steam within a few weeks of injection (Gulati and others, 1978). In the southeast Geysers, a 1989 tritium test of NCPA's well Y-5 showed tritium recovery within 1 day of injection. Also, a total of 27 percent of the tritium was recovered within 7 months from 33 steam wells. Beall, Enedy and Box (this volume) demonstrated that recovery of injectate as steam peaked between 35 percent and 50 percent in the southeast Geysers. These calculations were based on the elevated deuterium content of the injection-derived steam. In a similar study for the Unocal-NEC-Thermal (U-N-T) joint venture, Gambill (this volume) stated that the mass of injectate produced as steam in 1988 was roughly equivalent to 65 percent to 80 percent of the mass of liquid injected during that year.

LOW PRESSURE AREA INJECTION PROJECT

High flow rate declines in the southeast Geysers, starting in 1986, led to studies to augment condensate injection with excess fresh water as a means to improve reservoir performance. In order to better understand the role of water injection in the southeast Geysers, a joint injection project was conceived to quantify the ability of the reservoir to support and benefit from augmented water injection.

An agreement between NCPA, Calpine, and U-N-T delineated a general study area and called for the exchange of specific reservoir, geochemical, and geologic data within the Low Pressure Area (LPA) in August, 1989. In addition, U-N-T's microseismic monitoring system was expanded into the NCPA and Calpine leaseholds. The joint study area (Southeast Geysers Study Area) encompasses approximately 2,000 acres, and includes parts of PG&E's Units 13, 16, 18 and NCPA's Plants 1 and 2 (Figure 1). The LPA was defined as the area enclosed by the 220 psig (wellhead) contour as delineated on the January 1989 isobaric map. It contains approximately 790 acres. Figure 2 shows the outline of the LPA, the wellhead location of the data trade production wells, the mid-point of steam entries on the six injection wells, and the new microseismic stations within the study area.

NCPA and Calpine Corporation agreed to jointly deliver condensate to NCPA's C-Site. Well C-11 was chosen as the joint injector because of both its location within the heart of the low pressure area near the common lease line and its reservoir characteristics, which were considered ideal to maximize the return of injectate as steam. A schematic of the joint injection system is shown in Figure 3. Note that there are currently eight wells available for injection of condensate from the combined NCPA and Unit 13 plant areas with two additional wells proposed for conversion to injection. This reflects the philosophy that water needs to be distributed throughout the reservoir and injected at relatively low rates.

STUDY AREA RESERVOIR DESCRIPTION

The two primary formations which host the geothermal reservoir within the Southeast Geysers Study Area are (1) the Franciscan greywacke, which is a metamorphosed sandstone and (2) a silicic intrusive known as the felsite, which underlies the entire study area. Greenstone segments within the greywacke are a secondary host rock and can be of importance in specific areas. The main reservoir greywacke is overlain by a heterogeneous mixture of rock types which are normally set behind casing. Matrix permeability in these rocks is very low and extensive fracturing of these rocks has resulted in a high secondary permeability. Reservoir permeability-thickness product is a direct function of the size and distribution of fractures and faults open to steam flow and ranges between 20,000 and 200,000 md-ft. Although fracturing is extensive throughout the study area (especially within the LPA), the distribution is relatively random, with large blocks of the formation containing no major steam-bearing fractures. The lower reservoir boundary appears to be gradational in nature, with fractures becoming more widely spaced with increasing depth. Producing wells offset the study area in all directions except to the southwest which is bounded by a fault zone (Thompson and Gunderson, this volume; Beall and Box, this volume; Thompson, this volume; Maney and others, this volume).

The reservoir geology of the study area is distinguished from other portions of The Geysers by the relatively shallow depth of the felsite and the felsite's role as a major reservoir rock especially in the northwest (Unit 18) area. The northwest-southeast trending felsite intrusion is shallowest within the study area where it reaches sea level in the middle of Unit 18, and deepens to approximately 4,300 feet below sea level near injection well C-11. The felsite and greywacke are in hydraulic communication due to their similar static pressure gradient.

SELECTION CRITERIA

Through an ongoing reservoir testing and monitoring program, sufficient data were gathered to evaluate the spatial distribution of reservoir and fluid properties which led to the eventual selection of the LPA as an ideal target

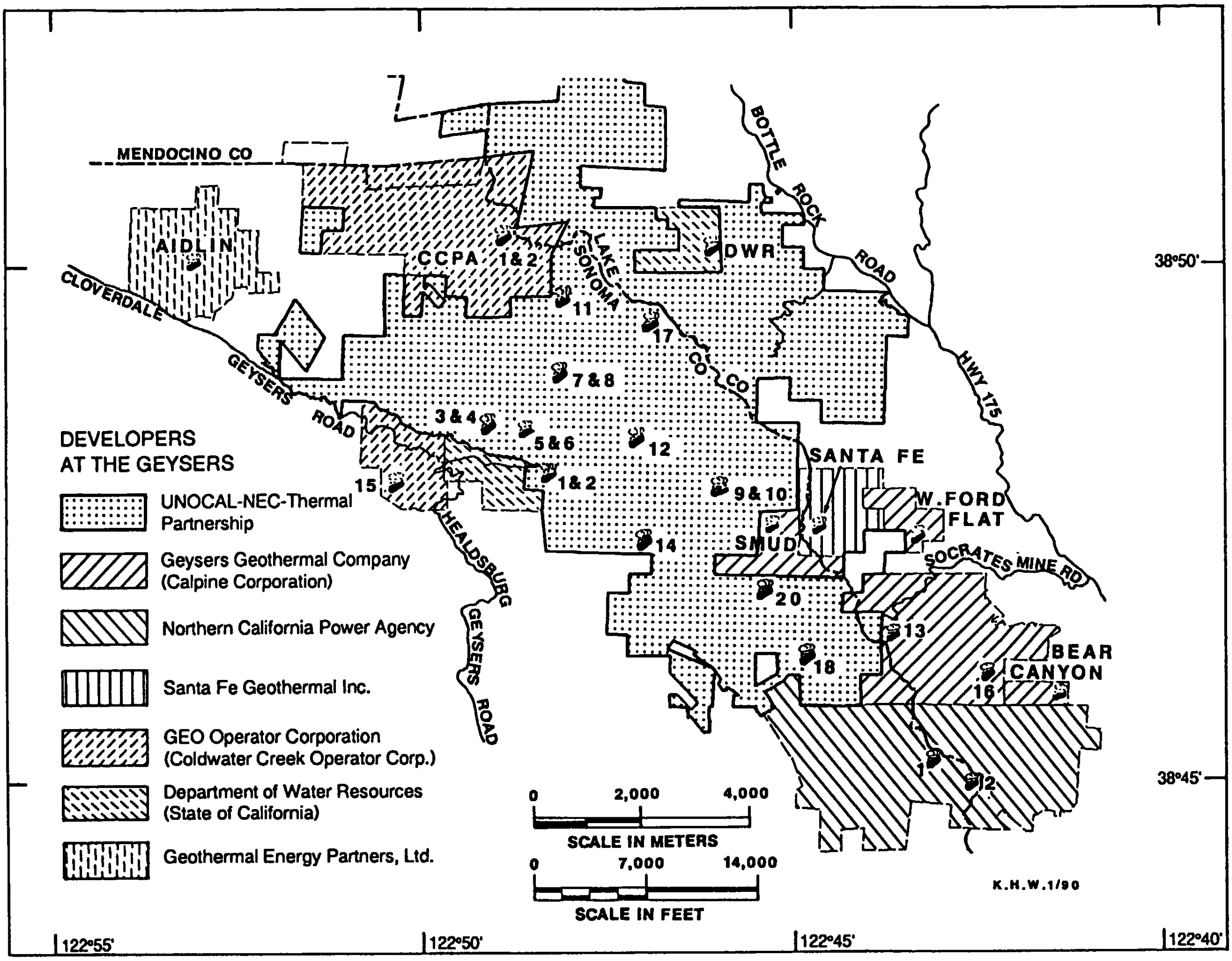

Figure 1. Geysers development map.

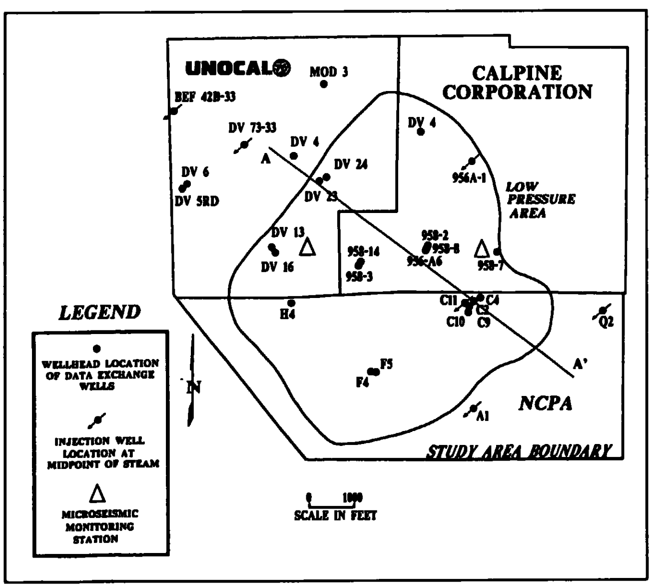

Figure 2. Southeast Geysers study area.

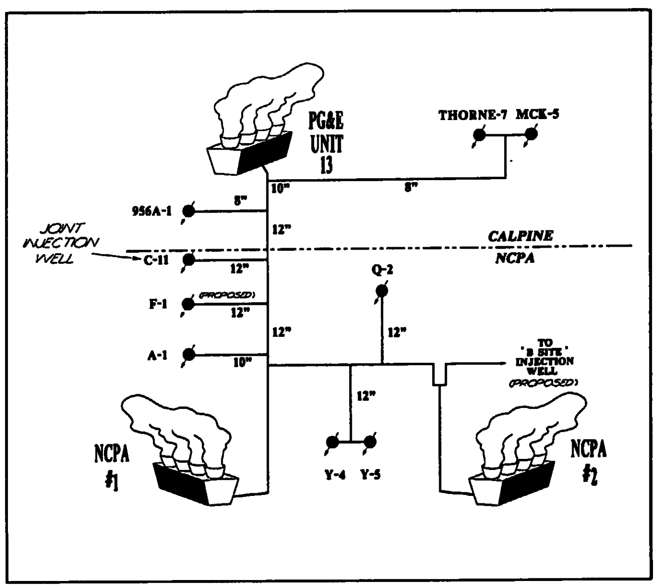

Figure 3. Injection schematic.

for water injection. C-11 was chosen as a joint injector due to both its location along the common lease boundary and the reservoir parameters listed in Table 1. These parameters are documented in papers presented in this volume (see references).

The most important criteria for selecting the LPA as an injection target was evidence of reduced or absent liquid saturation while substantial heat remained trapped in the reservoir rock. This information was supplied by a Pressure-Temperature-Spinner (P/T/S) logging program conducted over a 3 year period, which supplied a spatial and temporal evolution of both enthalpy and superheat within the LPA (Enedy, this volume, a).

Downhole superheat (SH) of up to 80°F was measured on well 956A-2 (Figure 4) in May 1988 after 8 years of production. As this well is completed in the LPA, the elevated SH indicates that the high rate of mass withdrawal is causing this portion of the reservoir to dry out. Additional evidence of reduced water saturation within the LPA was the increasing trend of downhole enthalpy with time. A modified Mollier diagram, shown in Figure 5, traces the progression of the calculated enthalpy and shows that the LPA wells range between 1,220 and 1,250 Btu/lb which is higher than the undisturbed portions of the reservoir (≈1,205 Btu/lb). Also, measured downhole temperatures of 450°F or greater indicate little or no temperature depletion. Other factors such as high flow rate decline and elevated boron concentrations also confirmed that the LPA was a prime target for liquid injection.

OPERATIONAL EXPERIENCE

During the next 9 months subsequent to September 20, 1989, approximately 2 billion pounds of condensate were injected at a nominal rate of 800 gallons per minute (gpm) Figure 6. However, C-11 was shut in on June 4, 1990 because of thermal breakdown with production well C-8.

Table 1. Parameters used to select injection targets.

Parameter	Source	Value
Reservoir Pressure	Based on PBU tests and P/T/S surveys	<220 psig-Feb89
Reservoir Temperature	Based on P/T/S surveys and geothermometers	>450°F
Reservoir Enthalpy	Based on P/T/S surveys	>1220 Btu/lbm
Fracture Distribution (Permeability)	Drilling history and P/T/S surveys	multiple entries (>5 per well)
Amount of Injection Derived Steam	Based on Deuterium concentration	<10 %
Steam Saturation	Based on gas equilibria using H_2, H_2O, CH_4, CO_2	>0.10

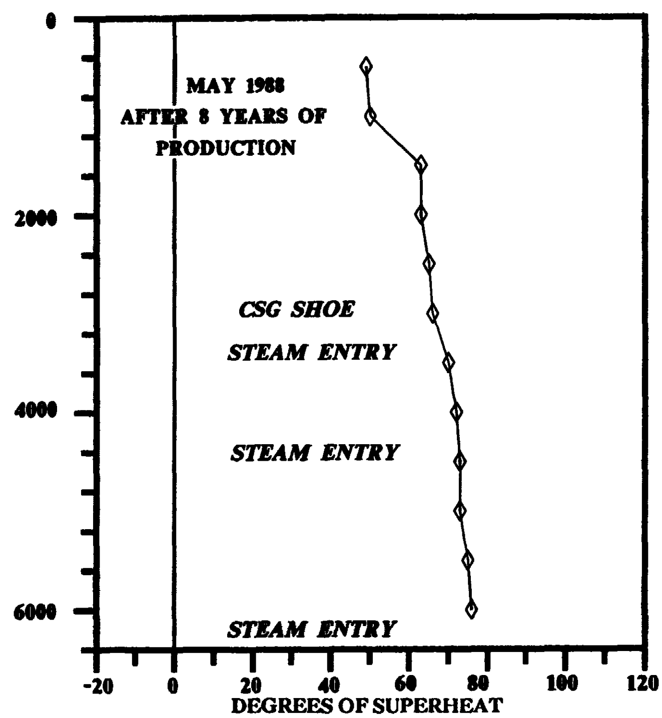

Figure 4. Superheat vs. depth (Calpine Well 956A-2).

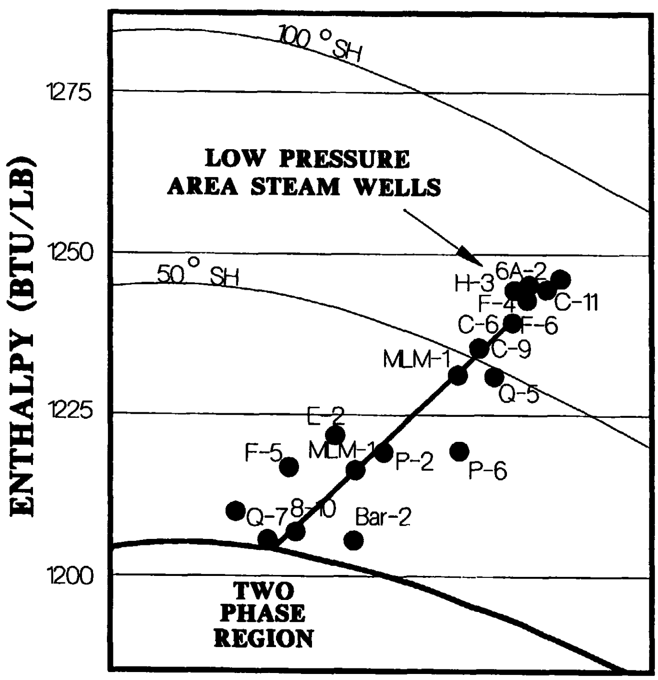

Figure 5. Modified Mollier Diagram flowing steam enthalpy southeast Geysers steam wells.

It was later found that a shallow bridge had formed in the C-11 wellbore casing condensate to flow through a shallow fracture system to offset production well. The injector remained shut in until a drilling rig cleaned out the well and a casing liner was installed. Injection resumed on August 21, 1990. However, the casing shut in until a second workover was successfully completed. Injection resumed at a nominal rate of 800 gpm on November 19, 1990.

C-11, the first joint injection well utilized at The Geysers, experienced no unusual operational problems as a result of its combined use by both Calpine and NCPA. Injection rates were held fairly constant (Figure 6), thanks to the cooperation of both the NCPA and Calpine field operators. Liquid level surveys indicated at moderate rates of 800 gpm or less, injection was confined to fractures located in the greywacke-greenstone reservoir between depths of 3,800 and 5,600 feet. Injection below that depth was limited by a bridge in the wellbore. The installation of the casing liner solved the thermal breakdown problem with offset steam well C-8.

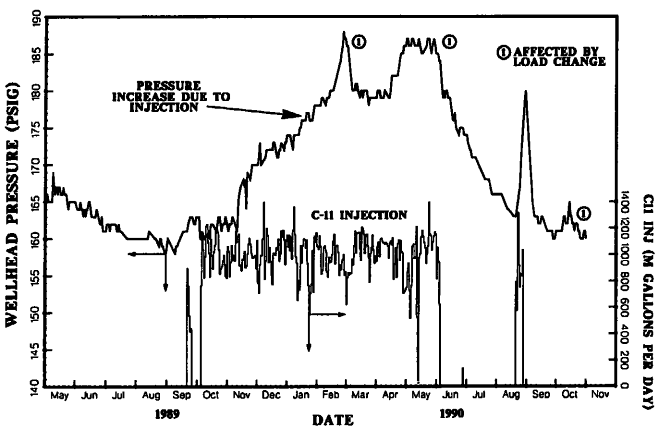

Figure 6. F-4 observation well pressures with C-11 injection rate.

RESERVOIR RESPONSE

The reservoir responses to the start-up of injection into the LPA consisted of changes in various reservoir properties including static pressures, flow rates, microearthquake response, geochemical changes, and rock temperatures.

Static Pressure Increase

The observed reservoir pressures within the LPA increased in many of the offset NCPA and Calpine production wells due to injection into C-11 and 956A-1. Reservoir pressure on observation well F-4, which is located 2,400 feet to the southwest of C-11, increased from 158 to 163 psig (+5 psi) within 10 days and to 180 psig (+22 psi or 14 percent) within 5 months (Figure 6). This higher pressure level was sustained until C-11 was shut in on June 4, 1990. The wellhead pressure then gradually declined to near the pre-injection level. Despite the 5-month shut in of injector C-11, F-4's shut in pressure of 162 psig in October 1990 was 15 psi higher than the extrapolated decline without injection. The sustained pressure support is a long-term benefit obtained from injection.

Finally, during August 1990, after only 8 days of injection, F-4's pressure increased from 165 psig to the previously observed maximum of 180 psig. The August pressure response was accelerated when contrasted with the initial pressure response. This effect most likely occurred because of a higher starting water saturation resulting from previous injection.

A second reservoir pressure response due to injection into C-11 was a decrease in interwell communication between the NCPA and Calpine steam fields. Specifically, during a 7-week overhaul of Unit 13, prior to LPA injection, the shut in pressure of F-4 increased from 168 psig or 23 psi (Figure 7). Immediately following plant start-up, the well's pressure started to decline and within 5 weeks returned to the original level. In contrast, after 7 months of continuous injection, only a 6 psi increase was measured following a 4 week Unit 13 curtailment associated with a plant cycling test. The elevated pressure level was maintained for approximately 2 weeks following the unit's start-up. Also, the preinjection outage response of 23 psi is similar to the 22 psi increase due to injection into C-11.

Analysis of the static pressure data indicates that water injection causes a change in the local reservoir boundary condition. Prior to injection, this area behaved like a closed, depleting system. Over short time periods, the post-injection behavior is like that of a constant pressure source system. The pressure support is supplied by the volumetric expansion of flashed injection water.

Individual Well Flowrate Response

Increases in individual well steam flow rate potentials ranging between 5,000 and 30,000 pounds per hour (lb/hr) were observed from 25 wells located within the LPA after 5 months of injection. The well midpoints of steam and magnitude of the increases are shown on Figure 8. Although all the wells are within the pressure sink, those

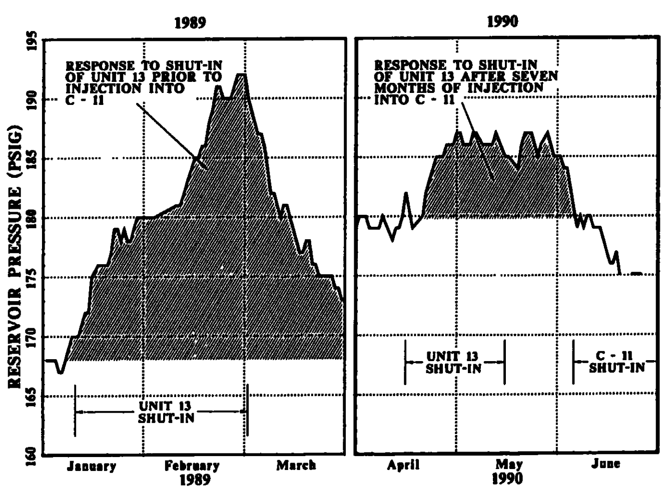

Figure 7. F-4 observation well pressure during offset unit shut down.

showing the largest increases are not in the center of the sink but are northwest and southwest of C-11. This indicates that the flow of flashed steam is controlled regionally by the static pressure distribution and locally by fracture orientation.

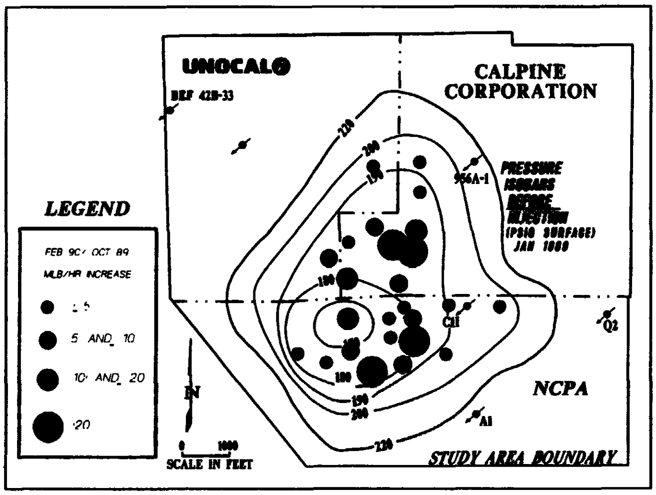

Figure 8. Location of wells with flow rate increases due to injection.

A typical flow rate decline curve for a responding well located on each of the three leases is shown on Figure 9. Calpine's 958-14 and NCPA's F-7 are both located roughly 1,800 feet from C-11, to the northwest and southwest respectively. Both wells started to increase in flow rate by late October, only 1 month after the start of injection into C-11 and continued to increase for the next 5 months at similar incline rates of 58 and 61 percent, respectively. Calpine's 958-14 increased from 95,000 to 125,000 lb/hr or 30,000 lb/hr. NCPA's F-7 increased from 22,000 to 30,000 lb/hr or 8,000 lb/hr.

U-N-T's DV-24 is located in the southeast corner of Unit 18 approximately 3,200 feet northwest of C-11. In late November 1989, DV-24 production flow rates began responding favorably to injection from C-11 (Figure 9). For 6 months prior, the production history of the well indicated a steady decline rate of 5 percent per year. From December 1989 through April 1990, production flow rates in DV-24 increased 7 percent from 81,000 lb/hr to approximately 87,000 lb/hr.

Total Flow Rate Response

An increase in total steam flow rate potential equivalent to 20 MW or 360,000 lb/hr was measured after 5 months from 23 NCPA and Calpine producers offset to the new injection wells. Figure 10 shows a plot of the combined flow rate potential increase at 140 psig for 14 NCPA wells along with the monthly production from those wells and injection into C-11. Flow rate increased at an annual exponential rate of 56 percent for 5 months. In comparison, the combined flow rate potential of seven responding

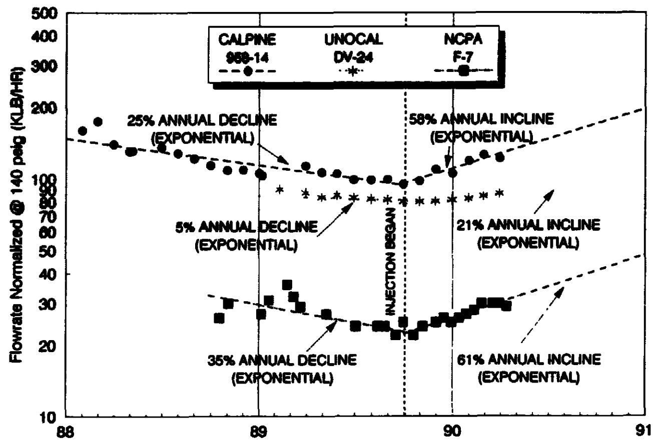

Figure 9. Historical monthly flowrate.

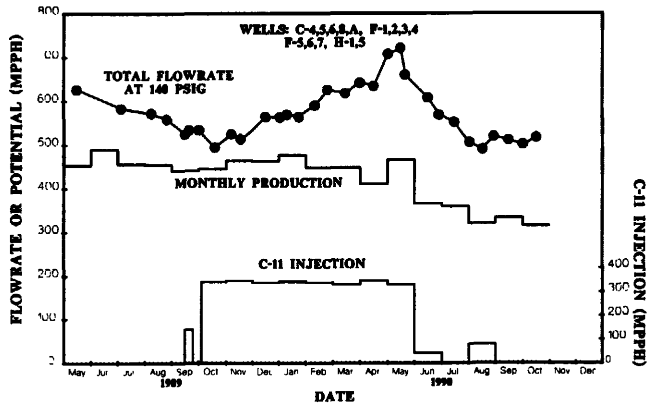

Figure 10. Total flow rate of NCPA wells, offset to injector C-11.

Calpine wells inclined at a similar 54 percent annual exponential rate (Figure 11). The overall reservoir benefit obtained from injection into C-11 and 956A-1 has been split almost evenly between the NCPA and Calpine steam fields. U-N-T has observed less injection response due to the greater distance between C-11 and U-N-T producers.

The material balance of LPA incremental injection and production indicates that injection into both C-11 and 956A-1 brought about the observed flow response. The percent contribution from each injector is not clear at this time. An increase of 2.4 billion pounds of steam was measured during the first year of injection. This was greater than the mass injected into either well and approximately 54 percent of the total injected mass into both. Following the shut-in of C-11, 956A-1's continued injection induced relatively lower production declines from offset wells (Figure 11). According to geochemical studies, these offset wells also continued to produce injection-derived steam.

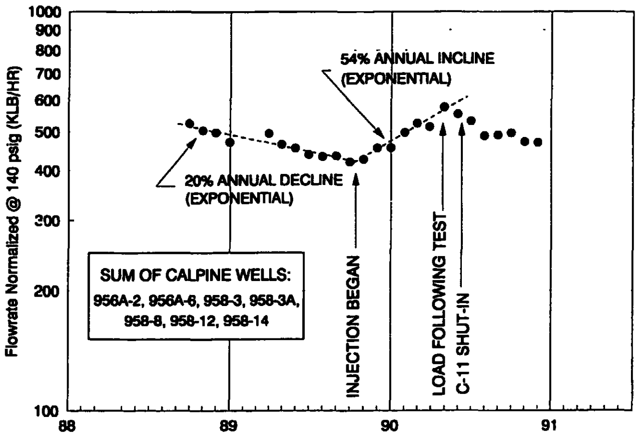

Figure 11. Total flow rate of Calpine wells, offset to injector C-11.

Microearthquake Response To C-11

The microearthquake (MEQ) cross section shown in Figure 12 was constructed on azimuth N 53° W through C-11 to show the seismic response to injection at C-11. All the MEQs located horizontally within 1,000 feet of the section line were included. The data indicate that there were very few events in the area prior to the start of extended injection in early October 1989. After the start of injection, however, a MEQ cluster formed in an area close to the wellbore of C-11 between approximately 2,600 and 4,600 feet below sea level. Stark (this volume) interpreted similar injection-related MEQ clusters on U-N-T leases as rough images of the presence of injected liquid. Therefore, Figure 12 would suggest that the injected fluids boil a short distance from the wellbore. In contrast, Stark's U-N-T examples showed MEQ clusters deeper and further away from the associated injection wellbore.

Based on the distribution of microseismicity, the majority of the liquid injected into the greywacke appears not to migrate deep into the felsite. Lower fracture density within the felsite may be the limiting factor. Although boiling appears to be primarily in the greywacke, wells completed in both zones produce injection-derived steam.

Geochemical Response

Additional evidence that injectate was boiling and being produced as steam is provided by shifts in both deuterium and noncondensible gas concentration. Figure 13 plots the deuterium values for two LPA wells and the injectate composition for C-11. NCPA's well H-4, near the edge of the LPA approximately 3,500 feet from C-11, continued to produce steam without an injection-derived-steam (IDS) component throughout the injection period. However, NCPA's well F-6, approximately 1,500 feet from C-11, produced an IDS component within 2 months of injection start-up to C-11. The IDS component ranged between 65 and 88 percent during the injection period. After the shut-in of C-11 in June 1990, IDS component returned to near pre-injection levels.

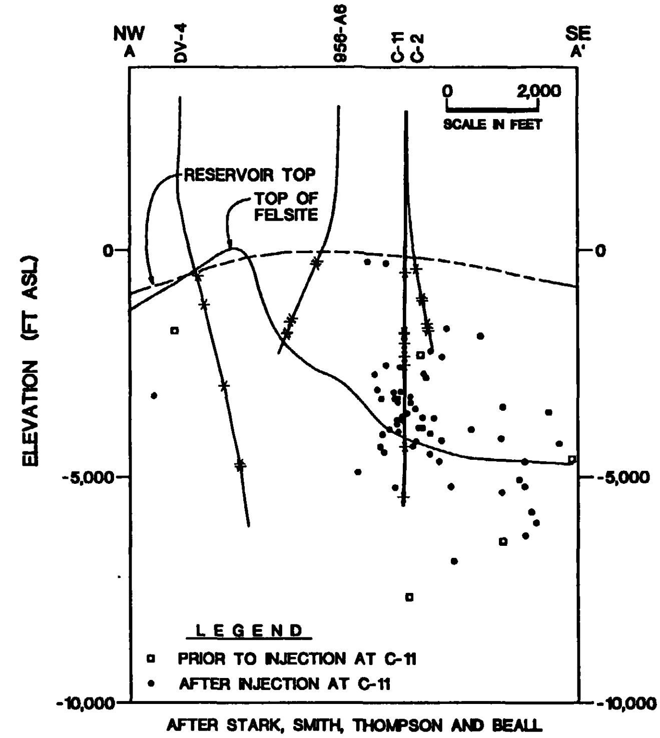

Figure 12. Microearthquake cross section, Azimuth N 53 W through C-11, September 1989-April, 1990.

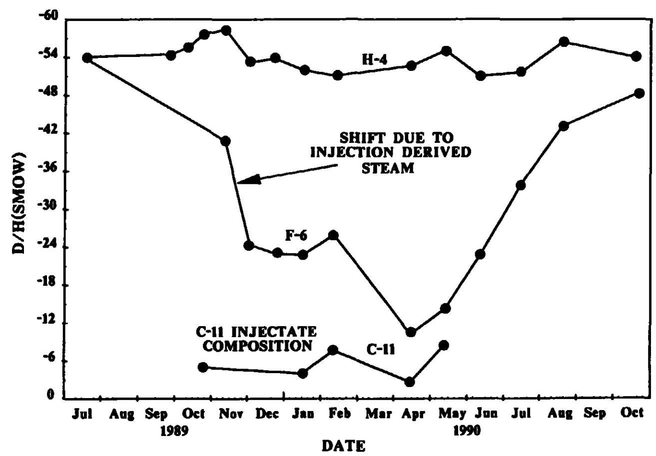

Figure 13. Deterium shifts selected wells in low pressure area.

Selected wells which produced injection-derived steam within the LPA showed a decrease in noncondensible gas (NCG) concentrations. NCG concentrations had been increasing throughout the southeast Geysers since 1986 (Maney and others, this volume). Figure 14 shows this increasing NCG trend in NCPA's well F-5 since 1986 through the start-up of C-11 in late 1989 which peaked at 1,550 ppm. Soon after injection began, NCG concentrations returned to a mid-1986 value of 590 ppm.

Steam Temperatures

No decrease in reservoir temperatures was measured on steam wells offset to the injectors during the 9-month

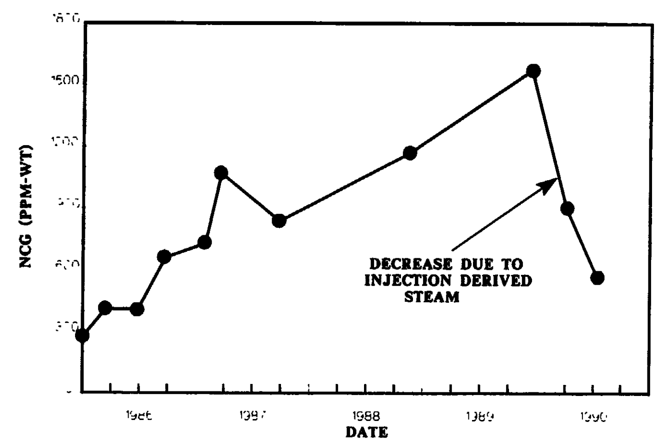

Figure 14. Well F-5, noncondensible gases vs. time.

injection period. This indicates that only a fraction of the total available heat capacity of the rock has been extracted. Figure 15 compares the downhole temperature profiles for well F-6 from pre- and post-injection P/T/S surveys. Well F-6 was stated in the previous section to have produced up to 88 percent IDS. The 1990 downhole temperatures measured 7 months after injection are essentially the same as the 1986 pre-injection temperatures.

The only measured decrease in downhole temperature occurred in the injector, C-11. Figure 16 contrasts the temperature profiles for C-11 just prior to the start of injection and 10 weeks following the C-11 shut-in. A 60°F decrease was measured at the primary greywacke injection zone between 3,800 and 6,000 feet.

CONCLUSIONS

The start up of new injection wells in the southeast Geysers resulted in a 20 MW increase in steam flow potential within 5 months from 25 wells offset to the injectors. These wells behave as if a constant pressure source has been introduced into the reservoir.

The Low Pressure Area Injection Project demonstrated that a properly planned injection project can "mine" or extract additional heat from the rock and positively impact both reservoir pressure and flowrate while minimizing thermal breakthrough to offset wells. These results suggest that further development of fresh water sources to enhance injection may well extend the life of the resource. Those injection projects found to be economically favorable would benefit the electrical consumer by increasing and extending power plant generating capacity.

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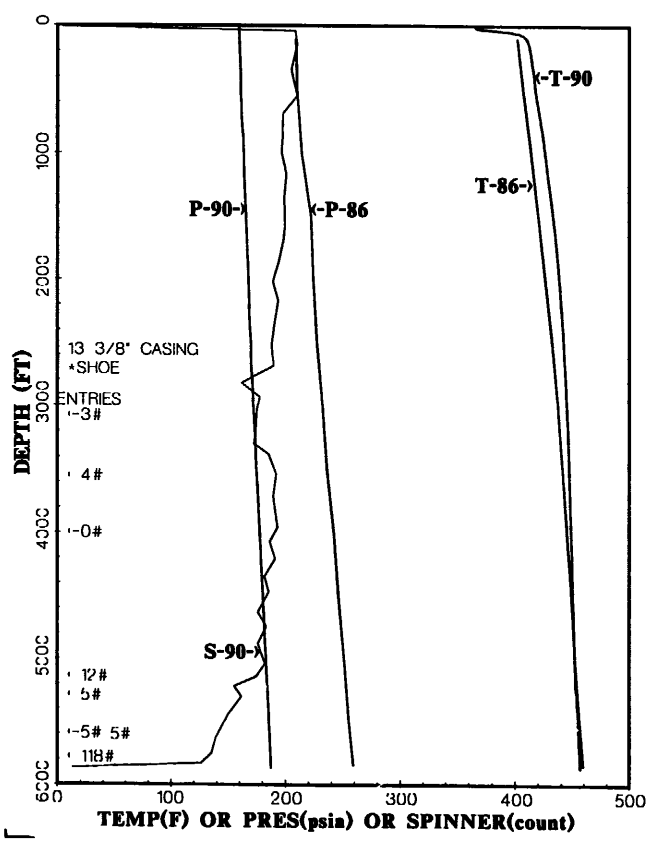

Figure 15. Pressure and temperature comparison, Well F-6, 1986 and 1990.

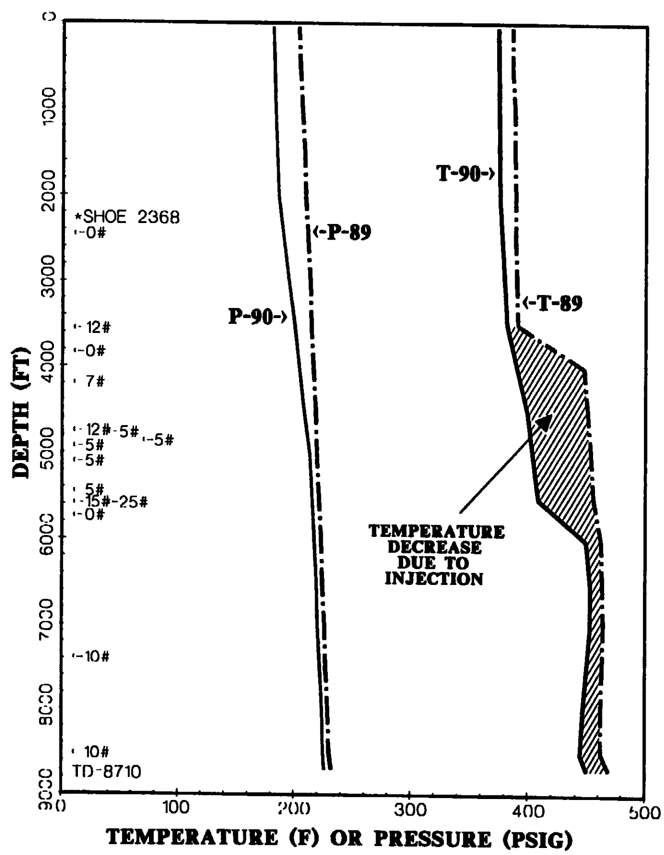

Figure 16. C-11 temperature and pressure survey on September 20, 1989 - 1/2-inch vent; survey on August 17, 1990 - 3-inch vent.

Mitch Stark, Ken Riedel, Kim Legg, Phil Molling, Debbie Wheeler; NCPA's Dick Yarter, Bill Smith, Steve Jones; Calpine's Tom Box, Joe Beall, Chris Dunkle. This paper is reproduced with permission of Stanford University.

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