INJECTION INFLUENCE ON PRODUCTION WELLS IN THE UNIT 13, UNIT 16, SMUDGEO#1, AND BEAR CANYON AREAS OF THE SOUTHEAST GEYSERS

Keshav Goyal

Calpine Corporation
Santa Rosa, California, USA

Key Words: Injection Recovery Factors, Injection Benefits, Injection, The Geysers

ABSTRACT

Steam production data from wells surrounding injection well CA 956A-1 in Unit 13, Barrows-1 in Unit 16, CA 1862-6 in SMUDGEO#1, and Davies Estate-4 in Bear Canyon were analyzed to estimate steam decline rates with and without water injection. The information was utilized to estimate annual and cumulative injectate recovery factors in these wellfields. Annual recovery factors, summarized in Table 1, range from less than 1% in SMUDGEO#1 to 73% in Unit 13. Injection benefits were observed in wellfields with low reservoir pressure (low boiling temperature), high steam enthalpy (dry reservoir with large heat contents), and high fracture density (large surface area for heat transfer). The methodology and results of this study can be helpful in designing future injection projects in vapor-dominated systems.

1. INTRODUCTION

Several steam field operators have found that water injection into the vapor dominated reservoir can be beneficial if performed properly (Goyal and Box, 1992; Enedy et al., 1991; Hanano et al., 1991; Gambill, 1990; Bertrami et al., 1985, and Cappetti et al., 1982). The positive contributions of water injection include providing reservoir pressure support, maintaining steam production rate, reducing makeup well requirements, and increasing reserves and life of the field by recovering a portion of approximately 90% of the heat which is stored in the rocks of vapor-dominated systems. Water injection can also cause a reduction in well productivity due to breakthrough in a production well or silica scale buildup in the wellbore and/or fractures.

In this paper, the effects of injection observed in four wellfields: Unit 13, Unit 16, SMUDGEO#1 and Bear Canyon (Figure 1) are presented and steam recovery due to injection in each wellfield is quantified by calculating recovery factors from the production data. The "recovery factor" is defined as the ratio of additional steam provided by injection to the amount of water injected over the same period of time. Additional steam is the steam produced at the new decline rate or improvement rate established due to injection minus the steam production calculated at a decline rate without injection.

Gambill (1990), Beall et al. (1989), and Beall (1993) have used geochemical data such as deuterium isotope and/or ammonia concentration in noncondensible gases as natural tracers to estimate the amount of injected water recovered in various parts of The Geysers geothermal field. The recovery factor defined on the basis of production data may be <u>different</u> than that defined on the basis of geochemical data if considered on a well-by-well basis. However, the combined recovery from all production wells affected by one or more injection wells should agree by both methods given sufficient time, since (i) the total amount of boiled water should appear as steam in production wells and be reflected in the production data and (ii) the steam originally to be produced from a given well but replaced by injection derived steam (IDS) should eventually be produced in other well(s).

Recovery factor calculations, similar to those presented in this paper, may not be possible under certain situations which include (i) a decrease in steam flow rate due to water breakthrough, (ii) scale deposits in the wellbore and/or fracture conduits, (iii) the fluctuating flow rate, and (iv) the completion of additional production wells in injection affected areas which impact the decline rates of nearby production wells as seen in the Unit 16 analysis. Therefore, the analysis presented in this paper is applicable <u>only</u> when the producers affected by the injection exhibit an increase in flow rate or a decrease in the decline rate or both.

2. UNIT 13 INJECTION WELL CA 956A-1

Originally a steam producer since the plant start-up in May 1980, well CA 956A-1 was converted to an injection well on October 30, 1989. This well satisfied the three criteria generally believed for an optimum injection location; (i) low pressure to initiate boiling at low temperature, (ii) high heat in a dried out area where large heat transfer can occur between **rock** and the injected water, and (iii) high permeability to provide a large surface area for heat transfer from the rock to the water. In 1989, the area southwest of CA956A-1, also called the Low Pressure Area (LPA) had a shut-in wellhead pressure lower than 210 psig, enthalpy in excess of 1230 Btu/lbm, and permeability in excess of 60,000 md-ft.

No perforated liner was installed in CA 956A-1. The majority of the injected water is believed to flow into the fractures which originally produced steam. From October 1989 to April 1993, most of Unit 13 injectate was divided between wells CA 956A-1 and an NCPA injection well C-11 (Enedy et al., 1991) with a small amount continuing to go to Thorne-7. Due to lower than expected direct benefits to Calpine, the condensate from Unit 13 being supplied to well C-11 was stopped in April 1993. All of Unit 13 steam condensate is now injected into CA 956A-1 and CA 956-2. Originally a production well, CA 956-2 was converted to an injection well in October 1993 (Figure 2).

<u>2.1 Production Wells Influenced by CA 956A-1</u>

Twelve wells surrounding injection well CA 956A-1 and shown by the smaller solid circles in Figure 2 were monitored for their flow rate and decline rate behavior. Most wells displayed a reduction in decline rate but the wells located within the dashed outline exhibited an increase in flow rate (Goyal, 1995).

The flow rate increase observed in the LPA wells suggest that most of the water injected into CA 956A-1 took a southwestern route and appeared as steam in wells located within the dashed outline (Figure 2). The pressure support to these LPA wells from C-11 was minimal as suggested by the tracer test conducted in C-11 in February 1991 (Adams et al., 1991). The tracer recovery in the LPA wells was of one order of magnitude lower compared to NCPA wells. Additionally, injection into C-11 was stopped from June to November 1990 but the improved performance of these wells continued (Figure 3). These observations suggest that recovery in the LPA wells was predominantly due to injection into CA 956A-1.

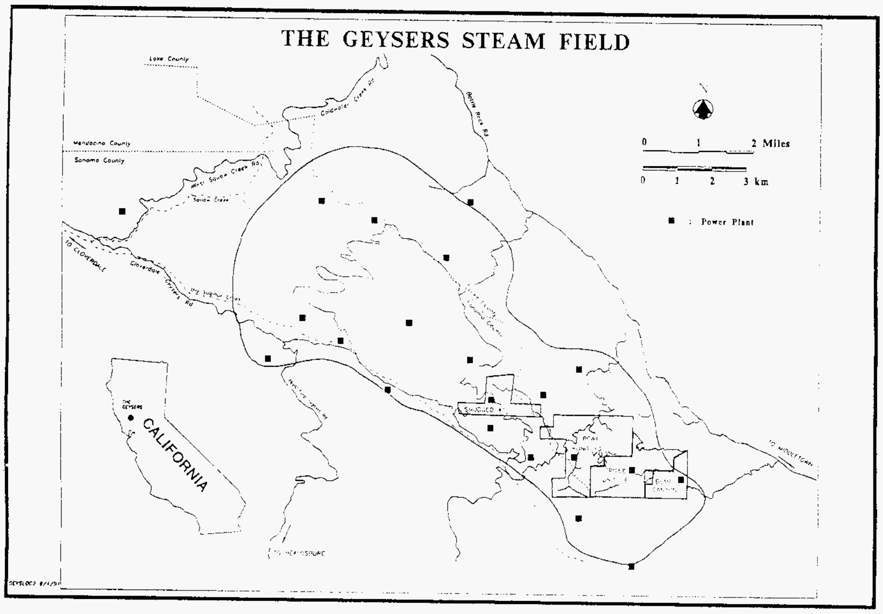

Figure 1 Location Map of the Geysers Geothermal Field and the Unit 13, Unit 16, Bear Canyon and SMUDGEO#1 Areas

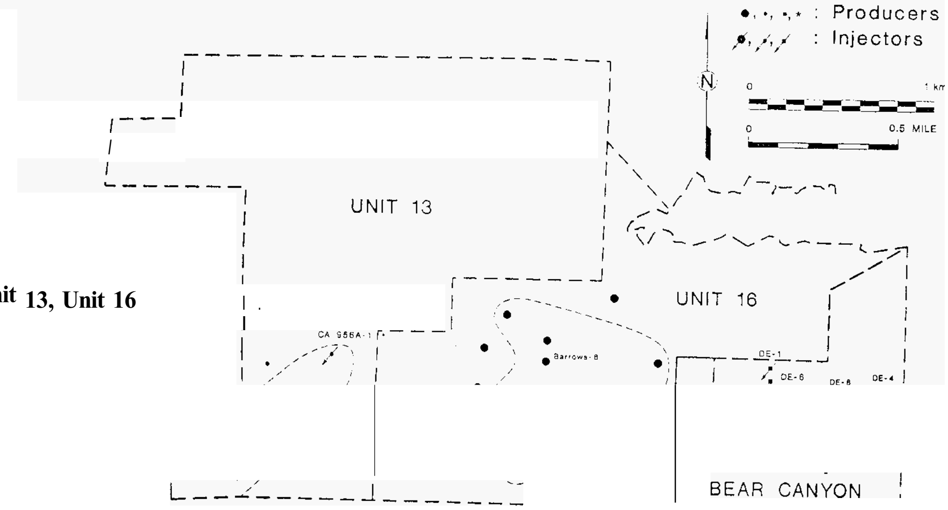

Figure 2 Study Areas in Unit 13, Unit 16 and Bear Canyon

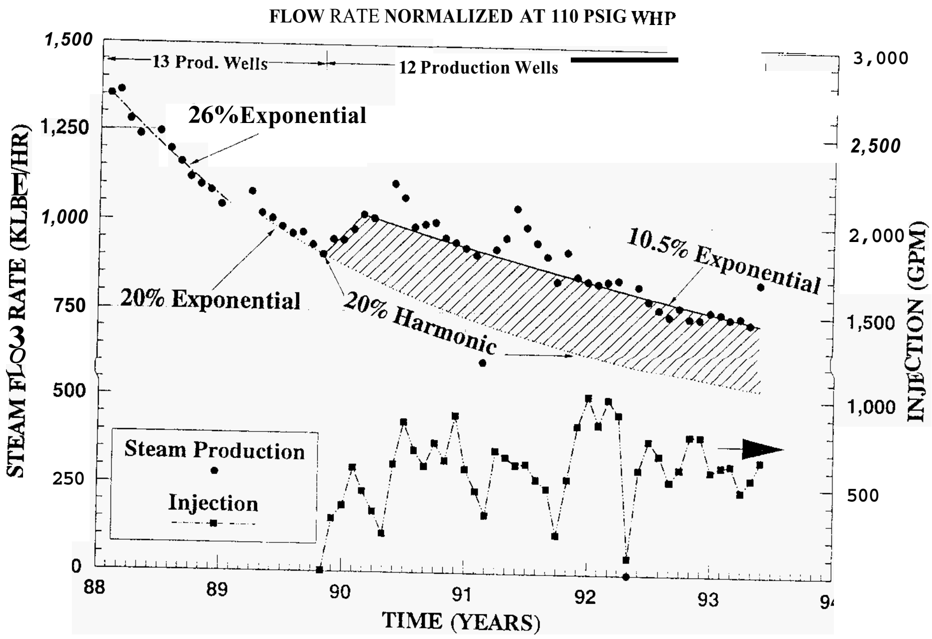

Figure 3 Effect of Injection into CA 956A-1 on Surrounding Production Wells

2.2 Recoverv Factors due to Iniection into CA 956A-1

In this study, a total of 13 production wells were considered: 8 wells located within the dashed outline showing maximum injection benefit and 5 nearby wells located outside the outline exhibiting some injection benefit (Figure 2). The combined normalized flow rate of all 13 wells at 110 psig wellhead pressure (WHP) is presented in Figure 3 from January 1986 to May 1993. Due to conversion of production well CA 956A-1 to an injection well, the flow rate of only 12 wells is plotted after October 1989.

The decline rates shown in Figure 3 are estimated by excluding the data points affected by plant outages and testing. The thirteen production wells exhibit an annual exponential decline of 26% in 1988 and 20% in 1989 before the start of injection into CA 956A-1 in October 1989. During the next four months, the flow rate of the remaining 12 wells increased by 110 klbm/hr. Subsequently, the flow rate of these wells declined but at a moderate rate of 10.5%. Injection into CA 956A-1 has helped in two ways: by providing an increase in the flow rate and by reducing decline rate (Figure 3). The monthly average injection rate (gpm) since start up in October 1989 is also shown in this figure which ranges from 300 to 800 gpm.

The hatched area in Figure 3 is the additional steam used to calculate the recovery of the injected water. In these calculations, it is assumed that the original 13 wells would have declined at a 20% harmonic rate starting October 1989. This assumption is consistent with the behavior of these wells in 1988 and 1989 (Figure 3) where a moderation in decline rate from 26% to 20% is seen as a result of a decrease in flow rate. This assumption is supported by the modeling effort of the Technical Advisory Committee appointed by the California Energy Commission (GeothermEx, 1992) where an output projection of the Geysers field matched a harmonic decline trend. Additionally, recovery factors calculated by using harmonic decline assumption will be conservative compared to those using exponential or hyperbolic trends.

Cumulative steam recovery as well as recovery factors (RF) for 3 years are shown in Figure 4. Steam recovery displays an increasing trend with time suggesting that the injected water continued to boil at an efficient rate during this time. A cumulative three year recovery factor of 61% is shown in Figure 4b. A slight decrease in the third year RF is caused by a 30% increase in the injected water in that year as presented in Table 1.

Annual recovery factors of 56%, 73% and 57% were estimated for the first, second, and third year respectively (Table 1). Reduced RF in the third year implies that increased injection did not enhance steam recovery correspondingly. It may be noted in Table 1 that steam recovered in the second and third year was almost equal, even though the annual injection in the third year was 30% higher than during the second year. This suggests that the injection rate should be kept close to 2500 million pounds per year or 600 gpm for an optimum boiling of the injected water.

The annual steam recovery presented in Table 1 can be converted in to MWh by using the Unit 13 steam usage factor of 20.5 klbm/MWh. This suggests that injection into CA 956A-1 provided 64,449 MWh (7.4 MW), 86,976 MWh (9.9 MW), and 88,498 MWh (10.1 MW) in the first, second, and third year respectively.

In summary, water injection in the southwest area of Unit 13 provided a three year cumulative recovery of about 61% and an enhanced electric generation of 239,923 MWh. This recovery may be slightly on the high side due to some pressure support provided by water injection into the NCPA well C-11. To date, no adverse injection effects such as cooling or water breakthrough have been noted in the production wells in this area as a result of the water injection into CA 956A-1.

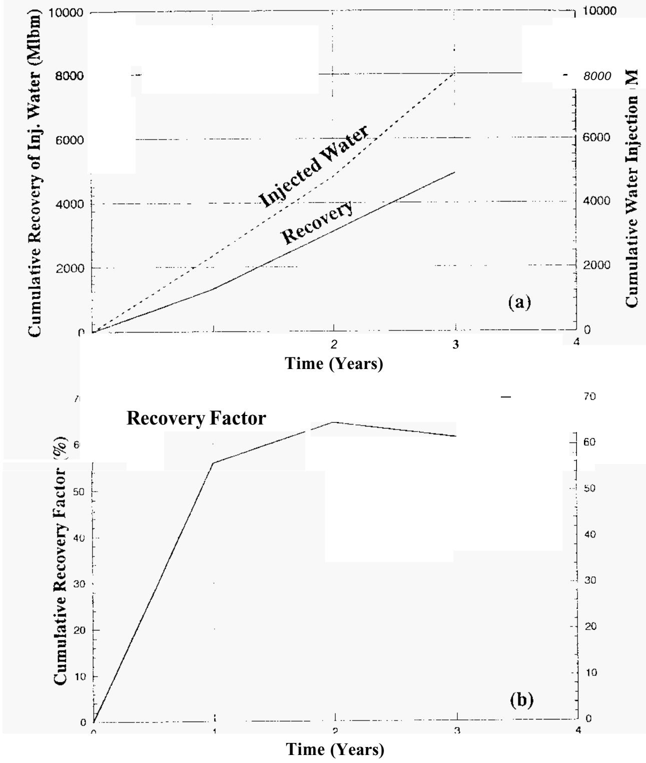

Figure 4 Cumulative Recovery Factors due to Injection into CA 956A-1

Table 1: Annual Injection Data and Recovery Factors in Various Areas of the Geysers Geothermal Field

Wellfield	Injection Well	Data	First Year	Second year	Third year
Unit 13	CA 956A−1	Injection (Mlbm)	2,363.5	2,451.1	3,190.5
		Recovery (Mlbm)	1,321.2	1,783.0	1,814.2
		or SI metric units			
		Injection (Mkg)	1,072.1	1,111.8	1,447.2
		Recovery (Mkg)	599.3	808.8	822.9
		Recovery Factor	56%	73%	57%
		Recovery (MWh)	64,449	86,976	88,498
		Recovery (av. MW)	7.4	9.9	10.1
Unit 16	Barrows−1	Injection (Mlbm)	2,658.3	2,195.5	
		Recovery (Mlbm)	540.3	1,114.8	
		or SI metric units			
		Injection (Mkg)	1,2058	9951	
		Recovery (Mkg)	245 1	505	
		Recovery Factor	20%	51%	
		Recovery (MWh)	30,017	61,93	
		Recovery (av. MW)	3.4	7.	
SMUDGEO#1	CA 1862−6	Injection (Mlbm)	2,027 9	3,375.	
		Recovery (Mlbm)	11 2	25.1	
		or SI metric units			
		Injection (Mkg)	919.9	1,530.	
		Recovery (Mkg)	5.1	11	
		Recovery Factor	0 6%	0 8%	
		Recovery (MWh)	772	1 786	
		Recovery (av MW)	0 1	0 2	
Bear Canyon	DE−4	Injection (Mlbm)	987 6		
		Recovery (Mlbni)	28 4		
		or SI metric units			
		Injection (Mkg)	448 0		
		Recovery (Mkg)	12 9		
		Recovery Factor	2 9%		
		Recovery (MWh)	1 7321		
		Recovery (av. MW)	0.2		

3. UNIT 16 INJECTION WELL BARROWS-1

A steam producer since the plant start-up in October 1985, Barrows-1 was converted to an injection well on October 1, 1990. No perforated liner was installed in this well. At that time, shut-in wellhead pressures of surrounding wells were around 230 psig and the enthalpy of the produced steam about 1230 Btu/lbm. The permeability in this area of Unit 16 ranged from 20,000 md-ft to more than 100,000 md-ft.

Water breakthrough to a nearby producer in early 1992 prompted a workover of Barrows-1. Installation of a 6-5/8" liner inside the original casing fixed the problem. Barrows-1 received a major portion of Unit 16 condensate between April 1992 and November 1993 at which time the injection rate was reduced to about 100 gpm due to water breakthrough in nearby producers.

3.1 Production Wells Surrounding Iniection Well Barrows-1

Fifteen production wells surrounding Barrows-1, shown by the larger solid circles in Figure 2, were monitored for their flow rate and decline rate changes due to injection into Barrows-1. Most wells displayed a reduction in decline rate and some wells, located within the dashed outline, even displayed a modest increase in flow rate (Goyal, 1995).

3.2 Recoverv Factors due to Water Iniection into Barrows-1

In the Unit 16 area, a total of 15 production wells were used in the analysis: 7 wells located within the dashed outline showing maximum injection benefit and 8 nearby outside wells indicating some injection benefit (Figure 2). The eastem-most well of this group belongs to the Bear Canyon project. The combined flow rate of all 15 wells normalized at 110 psig wellhead pressure is presented in Figure 5 from March 1989 to April 1993. Due to the conversion of Barrows-1, the flow rate of the remaining 14 wells is plotted after September 1990. The average monthly injection rate into Barrows-1 from October 1990 to April 1993 ranges from about 300 gpm to 700 gpm as shown in Figure 5.

All 15 wells display a combined annual exponential decline rate of 12% before the **start** of injection into Barrows-1. The shift of most of Unit 16 injection to Barrows-1 since October 1, 1990, has reduced the decline rate to 4% (Figure 5). However, an increase in flow rate, similar to that observed in the Unit 13 area (Figure 3), is not seen in the Unit 16 area (Figure 5). The post-injection decline rate of 4% increases to 20% due to increased steam flow and pressure interference by the new makeup wells: two legged CA 958-16 and a fork of McKinley-11. The converging trend of 20% exponential and 12% harmonic lines may appear to suggest that future injection benefits will diminish and even disappear after March 1993. This is **not** true because the 12% harmonic decline rate of original 15 wells should also increase due to the interference effect **of** new makeup wells. Since the increase in the decline rate of the original wells without injection into Barrows-1 is unknown, an assumption to calculate injectate recovery is made as discussed below.

1. The decline rate of the 15 wells without injection into Barrows-1 is projected as being 12% harmonic from September 1990 until March 1992. This assumption is similar to that made in Unit-13 calculations.

2. The steam recovery during the next six months after March 1992 (high decline period) is equal to that of the first six months. This assumption implies that steam recovery by injection during the 20% decline rate period has not diminished. This **is** reasonable since the increase in the decline rate is caused by 17% more steam extracted from the area by the new makeup wells. **This** increased steam withdrawal is expected to enhance the boiling rate as a result of the reduced boiling temperature associated with lower reservoir pressure. This assumption was also supported by a tracer test conducted in Barrows-1 in February 1993 where 66% of the R-13 Freon tracer (chlorotrifluoromethane) was recovered from the surrounding 10 wells within 30 days. More than 80% of the total recovered tracer came from the nearest new makeup well CA 958-16 (J. J. Beall-personal communication, 1993).

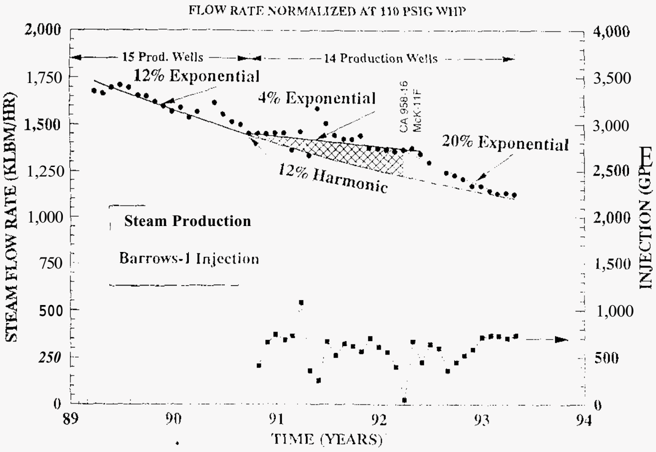

Figure 5 **Effect of Injection into Barrows-1 on Surrounding Production** Wells

3. The decline history of the 15 wells, shown in Figure 5, during 1989-90 and the 12% harmonic projection from September 1990 already takes into account the injection support provided by the water injected into CA 958-6. For 15 wells a decrease in water injection into CA 958-6 can only result in a decline rate higher than 12%. Therefore, the steam recovery shown by the hatched area in Figure 5 and the calculated recovery factors are considered conservative.

Cumulative steam recovery and water injection in Barrows-1 are presented in Figure ***6.*** Water injection into this well provided a two-year cumulative recovery factor of 34%. Annual recovery factors of 20% for the first year and 51% for the second year were achieved (Table 1). The annual steam recovery is equivalent to 30,017 MWh (3.4 MW) and 61,933 MWh (7.1 MW) in the first and second year respectively, for a Unit 16 steam usage factor of 18 klbm/MWh.

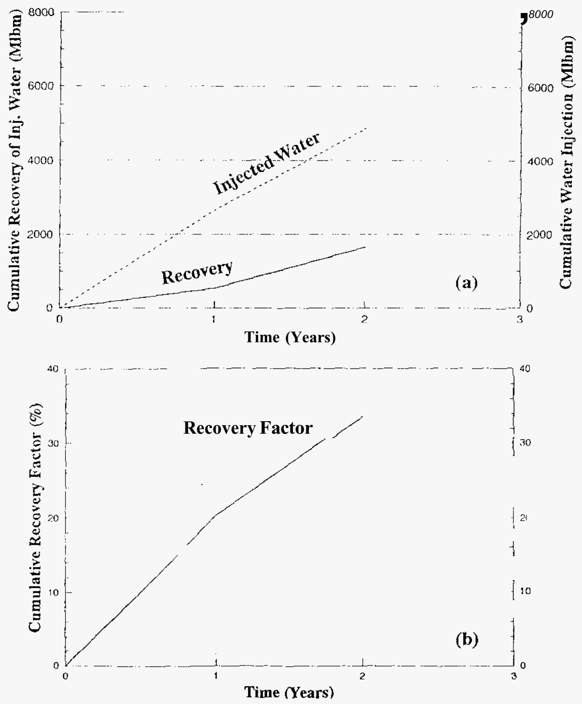

Figure 6 Cumulative **Recovery Factors due to Injection into Barrows-1**

In summary, a cumulative two year injection recovery of **34%** was realized in the Unit 16 area. This recovery is lower than the *64%* achieved in the Unit 13 area. Higher boiling temperature (higher reservoir pressure) and high fracture connectivity (water breakthrough) in the Unit 16 may be responsible for this performance. Recently, a decrease in flow rate of two nearby production wells, believed to be caused by water breakthrough from injection into Barrows-1, has been observed. As a result, the injection rate into Barrows-1 has been reduced to 100 gpm.

4. SMUDGEO#1 INJECTION WELL CA 1862-6

CA 1862-6, shown in Figure 7, has been accepting all the condensate from the SMUDGEO#1 (SMUD) plant since August 27, 1991. **No** perforated liner was installed in this well. Recently, due to an obstruction in the open section of the wellbore near the casing shoe, injectate started exiting the well at a shallow depth, affecting the nearby producers. Therefore, a workover was performed in December 1993 and a 6-5/8" liner was installed from the surface to approximately 600 feet below the casing shoe.

A tracer test was conducted in this well in December 1991 by injecting 232 pounds of R-13 Freon tracer (chlorotrifluoromethane). A total of **74%** of the tracer was recovered in 60 days, mostly from the wells in the SMUD area. In fact, 68% of the tracer was recovered from three wells: **55%** from CA 1862-18, 12% from CA 1862-19 and 1% from CA 1863-13 (J.J. Beall, personal comm., 1992). The proximity of these wells to the injection well suggests that most of the injected water benefits remained within the SMUD area (Figure **7).**

4.1 Recoverv Factors due to iniection into CA 1862-6

Consistent with tracer data, well CA 1862-18 derived the maximum benefit from this injection. Its decline rate decreased from 20% exponential in 1989-90 to 15% harmonic after injection into CA 1862-6 commenced in August 1991 (Figure **8).** The effect on other nearby wells was insignificant. The overall impact of the injection on the flow rate and the decline rate of the nearby wells was minimal as shown in Figure 9.

A flow rate increase in 1991, as shown in Figures 8 and 9, was caused by high header pressure (– 100 psig) operation of the surrounding power plants resulting in reduced steam withdrawal from the reservoir offsetting the SMUD area (TAC Consortium, 1992). Therefore, the flow rate just before the start of the injection is used as the initial condition to evaluate injection benefits in the SMUD area.

The combined normalized flow rate of wells CA 1862-18, CA 1862-19 and CA 1862-13 displays an annual exponential decline rate of 20% during 1989-90 (Figure 9). The decline rate reduced to an exponential rate of 6% for about 8 months after the start up of injection into CA 1862-6. Thereafter, the decline rate increased substantially. The flow rate data from August 1991 to August 1993 suggest an overall decline rate of 20% harmonic. Using the methodology discussed earlier, the net gain in these three wells due to injection is zero. It should be mentioned, however, that an injection rate above 500 gpm has a positive impact on the flow rate behavior of these wells as shown in Figure 9.

Using the hatched area in Figure 8 for CA 1862-18, annual recovery factors of 0.6% for the first year and 0.8% for the second year were calculated (Table 1). A two-year cumulative recovery factor of **0.7%** was also computed. These translate into a two-year generation of 2,558 MWh at a steam usage factor of 14,500 pounds per MWh. The injection recovery in the SMUD area is very poor though the wells produce superheated steam and the reservoir pressure is very low. It appears that the heat transfer characteristics (or the heat transfer area) in this region do not contribute to efficient boiling of the injectate.

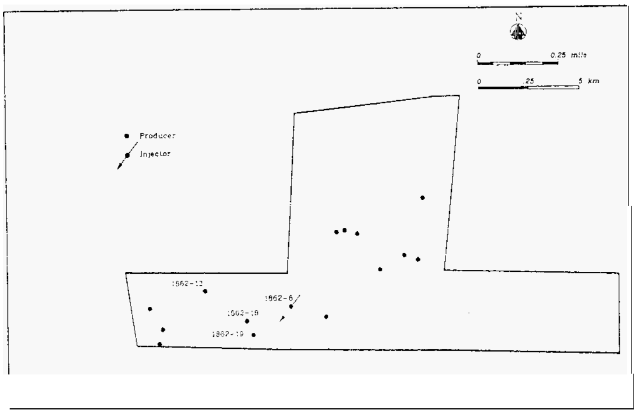

Figure **7** Injection Well **CA** 1862-6 **and** the Surrounding Production Wells in the **SMUD** Area

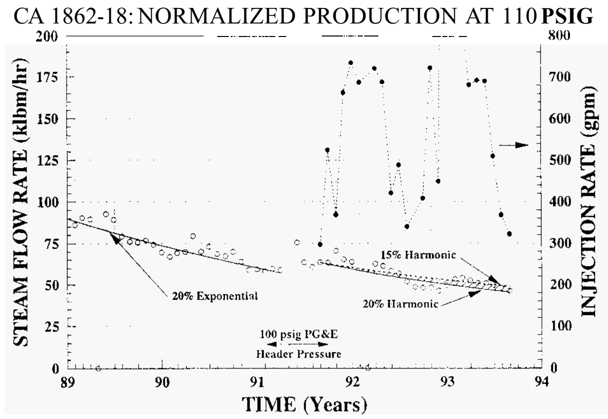

Figure **8** Effect **of** Injection into **CA** 1862-6 **on** the Production Well **CA** 1862-18

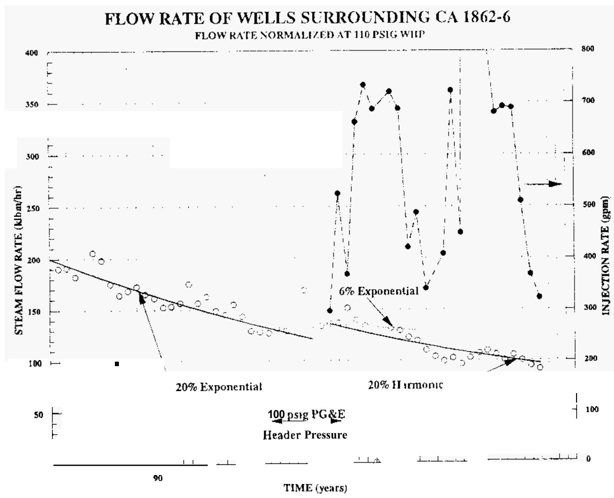

Figure 9 Effect **of** Injection into **CA** 1862-6 on the Surrounding Production Wells

5. BEAR CANYON INJECTION WELL DAVIES ESTATE-4

Davies Estate-4 (DE-4) has been accepting all the water from the Bear Canyon plant since its start up in September 1988 However, the original location of DE-4 was such that it resulted in water being injected to the east of the project without obvious benefits to the production wells. Therefore, the original leg of DE-4 was plugged and a new leg was drilled towards the producing area in July 1992. The new leg has been accepting all the water from the plant since August 1992. **No** adverse injection impact has been observed to date.

A tracer test was conducted in April 1993 by injecting 160 pounds of R-13 Freon tracer to evaluate the potential benefits derived from this well. The tracer was not seen in any of the wells for the first 13 days. Subsequently, a small amount was recovered from DE-9 followed by Davies State 5206-4 (DS-4), DE-7, DE-8 and DS-1 (J. J. Beall, Personal Communication 1993). The maximum tracer recovery was measured in wells DE-9 and DE-8. The cumulative tracer recovery in the Bear Canyon area was less than 1% even 110 days after the test, suggesting a slow boiling process of the injected water in this area. High reservoir pressures (higher than 260 psig wellhead pressure) and low fracture density (small heat transfer area) appear to be responsible for the slow boiling.

5.1 Recovery Factors due to injection into DE-4

The tracer test indicated a maximum recovery in wells DE-8 and DE-9. However, the effect of injection on the flow rate of these wells was too small to analyze. Only the data from DE-7 could be analyzed. The normalized flow rate of DE-7 from January 1991 to November 1993 is shown in Figure 10. The injection into DE-4 from August 1992 is also indicated in this figure.

DE-7 displays a 13% harmonic decline rate in 1991-92 until the start up of injection into DE-4 in August 1992 (Figure 10). Since then, its flow rate has shown an improvement at a harmonic rate of 11%. A recovery of the injected water is shown by the hatched area in this figure. On the basis of this area, a first-year recovery of 28.4 million pounds is calculated (Table 1). This amounts to a first-year recovery factor of 2.9% for an annual water injection of 987.6 million pounds. This steam recovery equates to 1732 MWh (0.2 MW) for a steam usage factor of 16.4 klbm per MWh.

6. CONCLUSIONS

Annual injection recovery factors of 56%, 73%, and 57% were estimated for the southwest area of Unit 13 for the first, second, and third year, respectively. A cumulative three-year recovery factor of 61% was obtained. Low reservoir pressure (or low boiling temperature) and large heat transfer area (high fracture density) are thought to be responsible for the efficient boiling of the injectate in this area. Unit 13 recovery factors may be slightly on the high side due to pressure support provided by water injected into NCPA well C-11. An injection rate of 600 gpm into CA 956A-1 is suggested for optimum boiling. To date, no adverse effects to injection such as cooling or water breakthrough have been noted by the injection into CA 956A-1.

Injection into Barrows-1 provided an annual recovery factor of 20% for the first year and 51% for the second year. The two-year cumulative recovery factor was 34%. Higher reservoir pressure and higher fracture connectivity between production and injection wells in the Unit 16 area compared to those in the southwest area of Unit 13 are believed to result in lower injection recovery factors. The injection in the Unit 16 area has not been trouble free. Water breakthrough problems do appear from time to time requiring workover of the injection wells.

Injection into the SMUD well CA 1862-6 has provided minimal benefits. One well CA 1862-18 did exhibit a reduction in the decline rate from 20% exponential to 15% harmonic. However, the annual and cumulative recovery factors were less than 1%. The injection recovery in the SMUD area is very poor though the wells produce superheated steam and the reservoir pressure is about the lowest in all four wellfields discussed in this paper. The poor heat transfer characteristics (poor fracture density) in this area prevent efficient boiling of the injectate. Problems related to water breakthrough and injection well workover were also encountered in the SMUD wellfield.

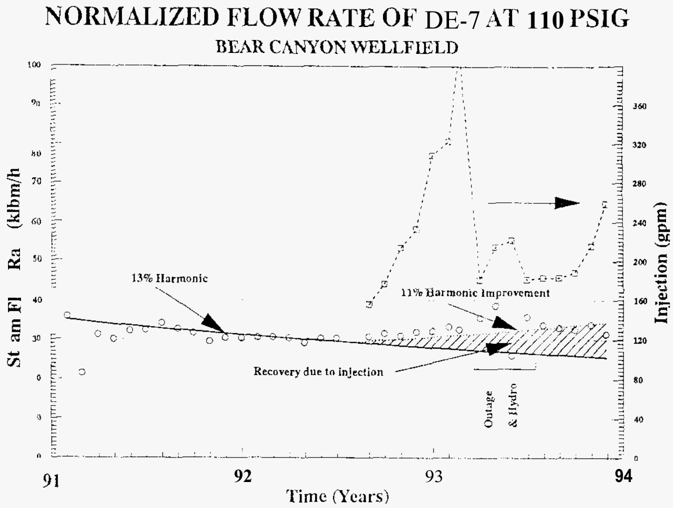

Figure 10 Effect of Injection into DE-4 on the Flow Rate of DE-7

In spite of slow boiling, injection has been helpful in the Bear Canyon area. Well DE-7 displays a continuous increase in its flow rate since the redrill of well DE-4. The production data of DE-7 suggests a first-year recovery factor of 2.9% and an enhanced electric generation of 1732 MWh. No adverse impact has been observed by injection into DE-4.

In general, large injection benefit is found in areas where heat transfer from the rock to the water is efficient. The characteristics of such areas are: low pressure (low boiling temperature), high steam enthalpy (dry reservoir with large heat content), and high fracture density (large surface area for heat transfer). Areas with high reservoir pressures and low fracture density result in poor heat transfer between the rock and fluid and small recovery of the injectate. High permeability, on the other hand, is found to result in water breakthrough and steam production loss.

ACKNOWLEDGEMENTS:

I would like to thank Tom Box and Charlene Wardlow for their helpful comments and Calpine Corporation and Santa Fe Geothermal Inc. for permission to publish this paper.

REFERENCES:

Adams, M.C., Beall, J.J., Enedy, S.L., and Hirtz, P. (1991). The Application of Halogenated Alkanes as Vapor-Phase Tracers: A Field Test in the Southeast Geysers. ***Geothermal Resources Council Transactions,*** Vol. 15, October 1991, pp. 457-463.

Beall, J. J. (1993). The history of injection recovery in the units 13 and 16 area of the Geysers Steamfield. ***Geothermal Resources Council,*** Transactions, v. 17, pp. 211-214.

Beall, J.J., Enedy, S. L., and Box, W. T. Jr. (1989). Recovery of injected condensate as steam in the south Geysers field. ***Geothermal Resources Council,*** Transactions, v. 13, pp. 351-358.

Bertrami, R., Calore, C., Cappetti, G., Celati, R. and D'Amore, F. (1985). A three year recharge test by reinjection in the central area of Larderello field: analysis of production data. ***Trans. Geotherm. Resour. Counc.*** **9(II)**, 293 298.

Cappetti, G., Giovannoni, A., Ruffilli, C., Calore, C. and Celati, R. (1982). Reinjection in the Larderello geothermal field. ***International Conference on geothermal energy,*** Florence Italy, May 11-14, 1982, Paper F1.

Enedy S., Enedy K., and Maney J. (1991). Reservoir Response to Injection in the Southeast Geysers. ***Proc. 16th Workshop on Geothermal Reservoir Engineering. Stanford University,*** pp. 75-82.

Gambill, D. T. (1990). The Recovery of Injected Water as Steam at The Geysers. ***Geothermal Resources Council Transactions,*** Vol 14, Part II, August 1990, pp. 1655-1660.

GeothermEx Inc. (1992). ***Fieldwide reservoir modeling of the Geysers Geothermal field, California,*** prepared for Lake and Sonoma Counties under a grant from the California Energy Commission, August 1992.

Goyal, K. P. (1995). Injection Recovery Factors in Various Areas of the Southeast Geysers, California, *Geothermics,* **24(2)** - In Press

Goyal, K. P. and **Box,** W. T. Jr. (1992). Injection recovery based on production data in unit 13 and unit 16 areas of the Geysers field. ***Proc. 17th Workshop on Geothermal Reservoir Engineering, Stanford University,*** pp. 103-109.

Hanano, M., Ohmiya, T. and Sato, K. (1991). Reinjection experiment at the Matsukawa vapor-dominated geothermal field: Increase in steam production and secondary heat recovery from the reservoir, ***Geothemics,*** **20(5/6)**, 279-289.

TAC Consortium (1992). ***Progress Report*** on ***Implementation of the Coordinated Resource Management Plan for The Geysers.*** Prepared by Calpine Corporation, Unocal Corp., NCPA, PG&E, SMUD and Russian River Energy Company, 41 p.

SI Metric Conversion Factors:

Btu/lbm	x 2.326	= kJ/kg
ft	x 0.3048	= m
gpm	x 0.0631	= l/s
inch	x 2.54	= cm
klbm	x 0.4536	= t or tonne
klbm/hr	x 0.4536	= tonne/hr or t/h
lbm	x 0.4536	= kg
md-ft	x 3.008×10^{-16}	= m^3
psi	x 6.894151	= kPa