

INJECTION RELATED COOLING IN THE UNIT 13 AREA OF THE SOUTHEAST GEYSERS

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ABSTRACT

The effect of eight-year water injection into well CA 956A-1 on wellhead temperature and enthalpy of the twelve nearby producers has been studied. Injection has been beneficial and without any water breakthrough to production wells. Producers with maximum injection benefit did not show any wellhead temperature or enthalpy degradation for approximately five years. Production wells, which showed no obvious injection effect, did not exhibit any thermodynamic degradation for up to six years. Some producers were not affected by injection at all. The thermal front appears to grow towards the southwest and east of the injection well. Upon the arrival of the thermal front, a drop of 1.3-5.7°F (0.7-3.2°C) per year in wellhead temperature and 0.3-2.3 Btu/lbm (0.7-5.3 kJ/kg) per year in wellhead enthalpy has been observed. The arrival of the thermal front signifies a slowing down in boiling rate and therefore, the recovery rate of the injected water.

INTRODUCTION

Water re-injection into geothermal reservoirs is a well-established practice throughout the world as discussed in the summary paper by Stefansson (1997). Fifteen years of re-injection in the Larderello-Valle Secolo area has not substantially modified the wellhead temperature of the surrounding five wells (Cappetti et al., 1995). In general, water injection is expected to provide pressure support as well as to cool the reservoir to some degree depending up on the duration of injection and the connecting fracture network. In this paper, the effect of eight years of injection on wellhead temperature and enthalpy of the nearby twelve producers located in the southeast Geysers is discussed.

Water injection into CA 956A-1 (Figure 1) started on October 30, 1989. No perforated liner was installed

in this well and the water was allowed to exit through the open-hole section of the wellbore below the 9-5/8" (0.244 m) casing shoe at 3008 feet (917 m) depth. The majority of the injected water is believed to flow into the fractures that originally produced steam. In 1989, the reservoir pressure in this area was below 260 psia (18 bars) at mean sea level. As of October 31, 1997, CA 956A-1 has accepted approximately 75 million barrels (12 billion liters) of water at 65-115°F (18-46°C) and zero wellhead pressure. Continuous boiling of this water by heat from the reservoir rock has provided pressure support along with increased steam flow rates and reduced decline rates to the surrounding wells as discussed by Goyal (1995). Positive results of CA 956A-1 prompted the conversion of CA 956A-2 to injection status effective October 15, 1993. Water breakthrough to two nearby production wells occurred as a result. Therefore, injection into CA 956A-2 was stopped on September 15, 1995. The well was placed back on production on October 20, 1995. Continuous steam production from the wells surrounding CA 956A-1 has caused the reservoir pressure to drop to below 170 psia (11.7 bars) at mean sea level even with the pressure support provided by eight years of injection.

Continuous water injection is expected to result in a plume moving away from the injection well. The injected water flows in the direction of a high hydraulic pressure gradient and good fracture permeability. The temperature difference between hot reservoir rock (-470°F or 243°C) and the relatively cold injection water (65-115°F or 18-46°C) causes a heat transfer from the rock to water which then boils and is converted into steam. The saturated steam moves in the direction of a high vapor pressure gradient and is expected to become superheated by gaining more heat from the hot dry rock while travelling to the production wells. It is not necessary that the direction of the hydraulic and vapor pressure gradients be the same.

Heat transfer mainly depends on surface area and the temperature difference between the rock and fluid (water or steam). It also depends on the travel time (velocity) because the longer the rock remains in contact with the fluid the more heat can be transferred. As the injection plume grows in size, the distance between the front of the plume and production wells (or the heat transfer area) decreases. In addition, the heat-supplying ability of the reservoir rock that has already cooled during the last eight years is reduced. Both of these mechanisms cause lower heat transfer from the rock, which in turn produces steam with lower enthalpy and lower temperature.

In the absence of downhole data, wellhead data for temperature and enthalpy of the produced steam are used to evaluate the effect of injection in this area. No attempt is made to convert the wellhead data to downhole conditions because of several uncertainties. The wellhead data are influenced by heat loss to the formation and to the atmosphere. Heat loss to the formation depends on flow rate, thermal conductivity of the rocks, wellbore radius, temperature gradient between the wellbore and the formation and a time function (Kanev et al., 1997). The latter two are unknown and can vary from well to well and therefore can not be accurately modeled. The heat loss at the surface depends on ambient conditions that vary all the time. Therefore, conversion to reservoir conditions would not significantly add to the data quality.

Continuous steam production causes a deficit in mass and a resulting drop in reservoir pressure. This drop, in turn, causes a decrease in the wellhead pressure in an un-throttled well. The Unit 13 wellfield has been producing with wide-open valves since 1988. A drop of approximately 5-psi (0.34 bar) per year is observed in the wellhead pressure of most of the producers given in Table 1. All wells, except CA 956A-2, produce superheated steam with a superheat ranging from 47°F (26°C) in CA 958-8 to 90°F (50°C) in CA 956A-6.

The effect of injection on wellhead temperature and enthalpy trends of various producers is summarized in Table 1. In general, the minimum thermal decrease, observed in wells CA 958-12 (1.3°F or 0.7°C/year, 0.25 Btu/lbm or 0.6 kJ/kg-year) and CA 958-3 (1.7°F or 1°C/year, 0.4 Btu/lbm or 0.9 kJ/kg-year), can be attributed to the excellent heat transfer characteristics in the area, the large distance from the injector and the high steam flow rate. The maximum decrease was observed in wells CA 958-3A (5.7°F or

3.2°C/year, 1.7 Btu/lbm or 4 kJ/kg-year) and CA 958-2 (5°F or 2.8°C/year, 2.3 Btu/lbm or 5.3 kJ/kg-year). These wells are low flow rate wells and, therefore, are expected to have high wellbore heat loss compared to high flow rate wells. Well D&V-2 and to some extent D&V-4 do not exhibit any temperature or enthalpy decrease and, therefore, are unaffected by water injection into CA 956A-1 so far. This observation suggests that the thermal front is not expanding towards the northwest of CA 956A-1.

Water injection into CA 956A-2 led to water breakthrough in wells CA 958-14 and CA 958-8. This caused a temperature and enthalpy drop of approximately 16°F (9°C) and 6 Btu/lbm (14 kJ/kg) respectively between pre- and post-injection values in these two wells (Table 1).

The remaining three wells, CA 956A-4, CA 956A-6 and CA 958-7 display temperature and enthalpy decrease in-between the minimum and maximum limits discussed above.

TEMPERATURE AND ENTHALPY DECREASE AFTER 5 YEARS OF INJECTION

As discussed by Goyal (1995), wells located within the dashed outline in Figure 1 received the maximum injection benefit. Out of seven wells, three wells (CA 956A-6, CA 958-3A and CA 958-3) were not affected by the adverse impact of injection into CA 956A-2. The injection induced thermal front from CA 956A-1 arrived at CA 956A-6 and CA 958-3 after five years of continuous injection. It took a year longer for this front to reach CA 958-3A (Table 1). The flow rate, temperature and enthalpy behavior of one representative well is presented below.

CA 958-3 This is the western most well of Unit 13 and located at the farthest distance from both injection wells as shown in Figure 1. The flow rate behavior of this well since 1987 is presented in Figure 2. Before the start-up of injection into CA 956A-1, it was declining at an annual exponential rate of 22%. It responded to water injection into CA 956A-1 and CA 956A-2 by exhibiting a flow rate increase of 20 and 7 klbm/hr respectively (Figure 2). The steam decline rate for the next 5 years remained almost zero. Thereafter, the steam flow declined at a 19% exponential rate as shown in Figure 2. This increase in decline rate coincides with the arrival of thermal front as indicated in Figure 3. The highest injection benefit was realized by CA 958-3 for the five years after the start-up of injection into CA 956A-1 as shown in Figure 2.

The wellhead temperature in CA 958-3 remained almost constant up to late 1994 as shown in Figure 3. Subsequently, a decrease of 1.7°F (1°C) per year in wellhead temperature and 0.4 Btu/lbm (0.9 kJ/kg) per year in wellhead enthalpy occurred signifying the arrival of the thermal front. At these rates, wellhead temperature and enthalpy dropped by approximately 5.5°F (3°C) and 1.3 Btu/lbm (3 kJ/kg) respectively by December 1997. Being at the farthest distance from the injector may have helped to reduce the effect of thermal degradation in this well.

TEMPERATURE AND ENTHALPY DECREASE AFTER 6 YEARS OF INJECTION

Five wells located outside the area of maximum injection benefit did not exhibit any noticeable increase in flow rate due to injection into CA 956A-1. Out of this group, only three wells (CA 958-2, CA 958-7 and CA 956A-4) display a decrease in enthalpy and temperature after six years of continuous injection into CA 956A-1. The flow rate, temperature and enthalpy behavior of one representative well is discussed below.

CA 958-7 This well is located south-southeast of CA 956A-1 as shown in Figure 1. The effect of injection into CA 956A-1 and CA 956A-2 on its flow rate is not noticeable as shown in Figure 4. For the most part of its production history, CA 958-7 underwent an annual exponential decline rate of 14%. The temperature data in Figure 5 suggest a constant wellhead temperature until mid-1995. A subsequent annual decrease of 2.5°F (1.4°C) in wellhead temperature and 1.4 Btu/lbm (3.2 kJ/kg) in wellhead enthalpy signifies the arrival of the thermal front. This suggests that wells, located outside the primary injection benefit area, did not encounter the thermal front for almost a year later than those within and that the thermal front is progressing in a southeasterly direction from CA 956A-1. Based on the decline trends shown in Figure 5, the wellhead temperature and enthalpy in CA 958-7 dropped by 6.3°F (3.5°C) and 3.5 Btu/lbm (8.1 kJ/kg) respectively by December 1997.

UNCHANGED TEMPERATURE AND ENTHALPY AFTER 8 YEARS OF INJECTION

Wells D&V-2 and D&V-4, located north of the area of maximum injection benefit shown in Figure 1, do not exhibit any wellhead temperature and enthalpy decrease due to injection. The effect of injection on the flow rate of these two wells was not clearly identifiable. Based on ammonia concentration, D&V-2 did not receive any injection benefit while

D&V-4 appears to have some benefit up to mid-1994 (J. J. Beall-personal communication, 1998). The wellhead temperature and enthalpy behavior of D&V-2 is shown in Figure 6. The wellhead enthalpy and temperature display a constant trend suggesting no thermal degradation during eight years of water injection into CA 956A-1 (Figure 6). These observations suggest that the thermal front is not expanding towards this area.

In summary, injection is primarily affecting the area southwest and east of injection well CA 956A-1. After five years of continuous injection, the temperature and enthalpy decrease were mostly confined to wells that benefited the most from the injection. This decrease was also experienced a year later by wells located southeast of CA 956A-1. Water injection resulted in a wellhead temperature and enthalpy drop of 5-8°F (2.8-4.5°C) and 1.5-4.5 Btu/lbm (3.5-10.5 kJ/kg) respectively by December 1997. Wells located to the northwest of CA 956A-1 do not exhibit any change in their thermal behavior suggesting no effect of injection in that area.

INJECTION WATER BREAKTHROUGH

Injection into CA 956A-2 led to water breakthrough to production wells CA 958-14 and CA 958-8 but not to a nearby producer CA 958-12 (Figure 1) suggesting a fracture dominated steam flow. The behavior of CA 958-14 and CA 958-12 is discussed below.

CA 958-14 The flow rate behavior of this well is shown in Figure 7. Its flow rate increased by approximately 30 klbm/hr (13.6 t/h) and 25 klbm/hr (11.3 t/h) following injection into wells CA 956A-1 and CA 956A-2 respectively. Wellhead enthalpy and temperature data of this well are shown in Figure 8. The temperature exhibited an increasing trend up to October 1993 suggesting a continuous drying-out of the reservoir even with the injection into CA 956A-1 for the last four years. This situation changed with the injection into CA 956A-2 where a drop in temperature as well as in enthalpy occurred as shown in Figure 8 suggesting water breakthrough to this well.

During the first two months of injection, steam flow rate increased by 25 klb/dhr (11.3 t/h) and wellhead temperature dropped by 66°F (36.7°C) as presented in Figures 7 and 8 respectively. During 1994, a significant drop in the flow rate (58 klbm/hr or 26.3 t/h) was observed as shown in Figure 7. A further drop in wellhead temperature was avoided by reducing the injection rate from 500 to 250 gpm (31.5

to 15.8 l/s) into CA 956A-2 and cleaning the scale deposits in the wellbore by a bridgebuster tool. In fact, the wellhead temperature was brought back to within 8°F (4.5°C) of the initial temperature by August 1994 (Figure 8). A pressure, temperature, and spinner survey run in November 1994 confirmed a water entry at a 5280-foot (1609 m) depth. The steam flow rate continued to drop and underwent another loss of 40 klbm/hr (18 t/h) in 1995 (Figure 7). The wellhead temperature dropped again by 74°F (41°C) in early 1995 and could not be fully recovered by cleaning the wellbore by bridgebuster or by blowing out the well to the atmosphere (figure 8). Therefore, the water injection into CA 956A-2 was stopped September 15, 1995. Since then, CA 958-14 has been drying up as indicated by a rise in both enthalpy and temperature (Figure 8). A bridgebuster or a rig cleanout is needed to recover the lost steam in this well.

CA 958-12 This well exhibited a flow rate response similar to that of CA 958-14 until December 1993 as presented in Figure 9; but quite a different response for wellhead enthalpy and temperature as shown in Figure 10. No water breakthrough occurred in CA 958-12 though it is located close to CA 958-14 (Figure 1). Well CA 958-12 also underwent a drying out from 1989 to October 1993 (Figure 10). A gradual decline of wellhead temperature (1.3°F or 0.7°C/year) and enthalpy (0.25 Btu/lbm or 0.6 kJ/kg-year) in this well coincides with a startup of injection into CA 956A-2 in October 1993 as shown in Figure 10. However, an increase in temperature, as expected after ceasing the injection into CA 956A-2, did not occur (Figure 10). These observations suggest that the thermal front to CA 958-12 was affected but not dominated by injection into CA 956A-2. In other words, the thermal front from CA 956A-1 and heat loss to the formation and ambient were mainly responsible for the minimal thermal degradation in CA 958-12. Similar to CA 958-3 (Figure 2), the highest injection benefits were realized by this well for the five years after the start-up of injection into CA 956A-1 as shown in Figure 9. High decline rate, coinciding with the arrival of thermal front, suggests a slowing down in boiling rate and the recovery rate of the injected water.

COMBINED ENTHALPY BEHAVIOR

The flow rate weighted average enthalpy behavior of all wells, except three, is shown in Figure 11. Three wells that underwent thermal breakthrough, CA 956A-2, CA 958-14 and CA 958-8, are excluded from this plot. This figure shows a constant enthalpy trend up to the third quarter of 1994, suggesting no

thermal degradation due to injection for the first five years. Afterwards, enthalpy declines at a rate of 0.3 Btu/lbm (0.7 kJ/kg) per year as indicated in this figure due to the expanding thermal front. This small decrease in enthalpy is the result of steam flow dominated by wells that exhibited little or no decrease in enthalpy. The flow rate of these wells accounted for approximately 60% of the total flow rate of nine wells.

COMBINED FLOW RATE BEHAVIOR

Figure 12 shows a plot of combined flow rate versus time for all wells considered to be influenced by injection into CA 956A-1. The combined flow rate of twelve production wells shows an increase in decline rate from 10.5% to 13% exponential starting in late 1994. This observation is consistent with a decrease in boiling efficiency of the injected water due to the arrival of the thermal front. A comparison of Figures 11 and 12 confirms the efficiency decrease starting in late 1994. A further increase in steam decline rate can also be observed in 1996 and 1997. Besides thermal front, some of the decrease in steam flow rate, shown in Figure 12, can also be attributed to the changes created by scale deposits in fractures and changes in NCPA operations starting in early 1996.

HEAT TRANSFER IN A HOMOGENEOUS POROUS RESERVOIR

By the time of the arrival of thermal front in September 1994, injection wells CA 956A-1 and CA 956A-2 accepted a combined water volume of 44.4 million barrels (7 billion liters) at a wellhead temperature of 65-115°F (18-46°C). This amount affected producers located within the dashed outline that covers an area of approximately 106 acres (0.43 square km). At that time, steam had a wellhead enthalpy of approximately 1233 Btu/lbm (2868 kJ/kg) as shown in Figure 3. A downhole enthalpy of 1261 Btu/lbm (2933 kJ/kg) can be estimated allowing for a wellbore heat loss of 28 Btu/lbm (65 kJ/kg) as observed in the downhole P/T/S survey of CA 956A-6 in December 1993.

For an average 50% recovery, the injected water needs to extract 9.3 trillion Btu (9.8 trillion kJ) of heat from rocks to convert it from 90°F (32°C) water to a superheated steam at 1261 Btu/lbm (2933 kJ/kg). The remaining 50% of the injectate is assumed to extract heat until it boils at the present reservoir pressure of 170 psia. This conversion to boiling water will extract additional 2.2 trillion Btu (2.3 trillion kJ) of heat from the rock. To lose the total

heat of 11.5 trillion Btu (12.1 trillion kJ), the rocks with 6% porosity covering an area of 106 acres (0.43 square km) should drop in temperature by approximately 15°F(8°C).

For a fracture-dominated reservoir, such as The Geysers, the area for heat transfer should be less than that used in this example of a homogeneous system. Assuming that only a 30% of the rock comes in contact with the injected water, the rock temperature should then drop by approximately 45°F (25°C). Such high drop in the rock temperature is expected to reduce boiling efficiency to some extent. Additionally, the obstructions created by the scaling in reservoir fractures and wellbores are also expected to reduce steam flow rate.

Considering trouble free high heat recovery from the injection in CA 956A-1 for 5 years, a cumulative injection of 45 million barrels (7 billion liters) of water in a given area should be used as a guide to move the injection to another location or to reduce the injection rate.

CONCLUSIONS

Injection into CA 956A-1 continues after eight years without water breakthrough to nearby production wells. Most of the injection benefit has been derived by production wells located within the dashed outline shown in Figure 1. These wells display no wellhead temperature or enthalpy decrease for approximately five years after the start of injection into CA 956A-1. The highest injection benefit was realized during these five years.

For producers located outside the dashed outline, temperatures remained constant for approximately six years before a decrease was observed. Injection benefits in these wells were so small that they could not be clearly identified by their flow rate behavior. The wellhead temperature and enthalpy data suggest that the thermal front grows towards the southwest and east of injection well CA 956A-1.

The lowest rate of decrease in wellhead enthalpy and temperature is observed in high flow rate wells CA 958-12 and CA 958-3 both located at a far distance from the injector. The highest rate of decrease is observed in small flow rate wells CA 958-3A and CA 958-2. Well D&V-2 does not exhibit any

temperature or enthalpy decrease suggesting no injection influence towards this area thus far.

Water injection has contributed to a wellhead temperature drop of 5-8°F (2.8-4.5°C) in producers between late 1994 and December 1997.

Two-year injection into CA 956A-2 resulted in water breakthrough to production wells CA 958-14 and CA 958-8 but not to nearby producer CA 958-12, suggesting a fracture dominated steam flow in the field.

Arrival of the thermal front signifies a slowing down in the boiling rate and therefore, the recovery rate of the injected water. Flow rate decrease appears to be caused by both scaling as well as a drop in the rock temperature.

As a general guide to obtain a high recovery rate, injection water should be moved to another location in the southeast Geysers or the injection rate be reduced if the cumulative amount exceeds 45 million barrels (7 billion liters).

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No.	Well name	Flow Rate	Flow Rate or M (klbm/hr) Behavior	Enthalpy or H (Btu/lbm) Behavior	Temperature or T (°F) Behavior
1	CA 956A-2	13	Flow increase due to injection into CA 956A-1. Flow drop (23 klbm/hr) due to setting a downhole plug.	H dropped from 1228 to 1186 due to injection in this well. Constant enthalpy (H) trend.	T dropped by 84°F due to injection into this well. Constant T behavior thereafter
2	CA 956A-4	41	No obvious injection effect from either well.	Drying out up to mid-YS and drops thereafter at 1.8 Btu/lbm-yr. Wellhead H drop = 4.5 Btu/lbm.	T behavior consistent with H and drops at 3.3°F/yr. Wellhead T drop = 8.3°F
3	CA 956A-6	52	Flow increase due to both wells & high decline starting from late 1994.	Drying out up to 8/94 and drops at 0.8 Btu/lbm per yr thereafter. Wellhead H drop = 2.6 Btu/lbm	T behavior consistent with H and drops at 1.8°F/yr. Wellhead T drop = 5.9°F
4	CA 958-2	17	Small flow increase (?) from either well. A small flow rate well.	Drying out up to mid-95 and drops at 2.3 Btu/lbm-yr thereafter. High heat loss at low M.	T consistent with H & drops at 5°F/yr. High heat loss at low M
5	CA 958-3	46	Flow increase due to both wells & high decline starting from late 1994	H drops from late 1994 at 0.4 Btu/lbm-yr. Wellhead H drop = 1.3 Btu/lbm	T constant up to 8/94 and drops at 1.7°F per year thereafter. Wellhead T drop = 5.6°F
6	CA 958-3A	28	High increase from CA 956A-1 and small increase from CA 956A-2.	H constant up to late-YS & drops at 1.7 Btu/lbm-yr. High heat loss at low M	T constant up to mid-95 and drops at 5.7°F/year thereafter
7	CA 958-7	38	No obvious injection effect from either well	Drying out up to mid-95 and drops at 1.4 Btu/lbm-yr thereafter. Wellhead H drop = 3.5 Btu/lbm	T behavior consistent with H and drops at 2.5°F/yr. Wellhead T drop = 6.2°F
8	CA 958-8	29	Flow increase in both cases. Water breakthrough from CA 956A-2	Water breakthrough. H lower by 6 Btu/lbm compared to value before 10/93 injection start-up.	T constant until inj. into A-2. Temperature dropped by 17°F & remained constant
9	CA 958-12	83	Flow increase by injection in both wells	No water breakthrough. Initial drying up. H drops at 0.25 Btu/lbm-yr. Wellhead H drop = 1 Btu/lbm	T behavior consistent with H and drops at 1.3°F/yr. Wellhead T drop = 5.5°F
10	CA 958-14	70	Flow increase in both cases. Water breakthrough from CA 956A-2.	Drying-up until water breakthrough. H continues to be lower by 6 Btu/lbm. Drying up.	T constant until injection into CA 956A-2. Wellhead T dropped by 15°F.
11	D & V-2	58	No obvious injection effect from either well.	H constant throughout	T constant. Slight drop - 4°F
12	D & V-4	62	No obvious injection effect from either well.	Scattered data. Constant H.	Scattered data. Constant T.

Table 1: Low Pressure Area: Effect on Injection into CA 956A-1 and CA 956A

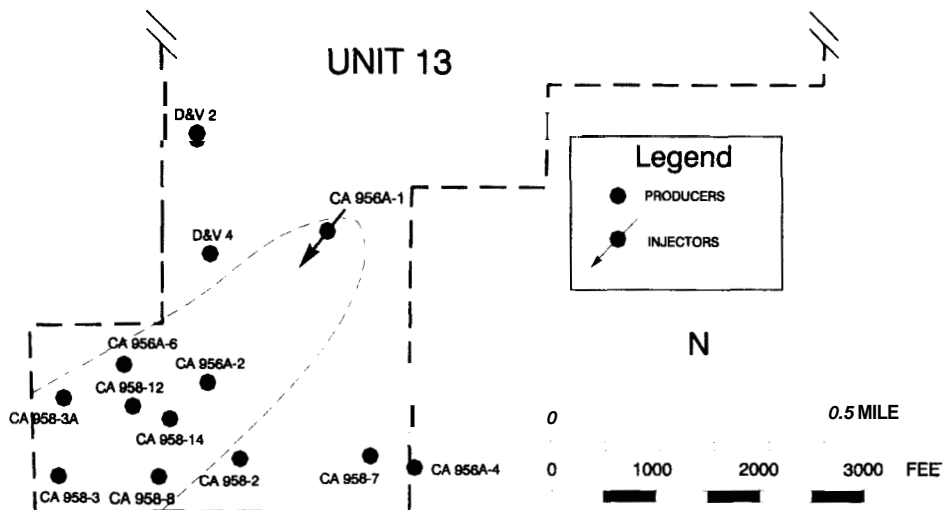


FIG. 1: Study Area in Unit 13

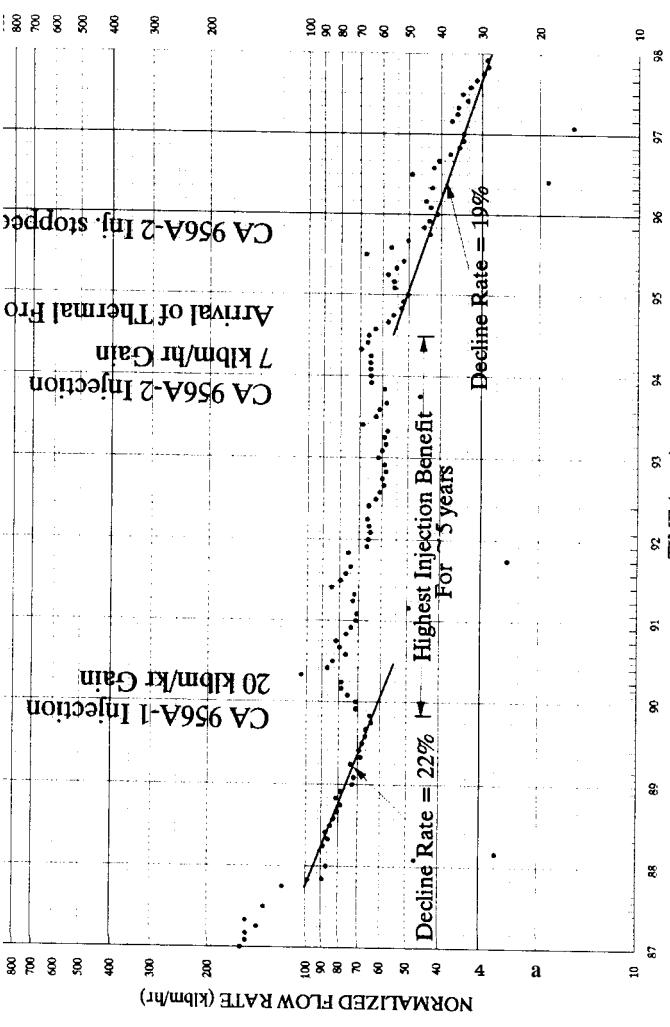


Figure 2. Normalized flow of CA 958-3 at 110 psig wellhead pressure versus time

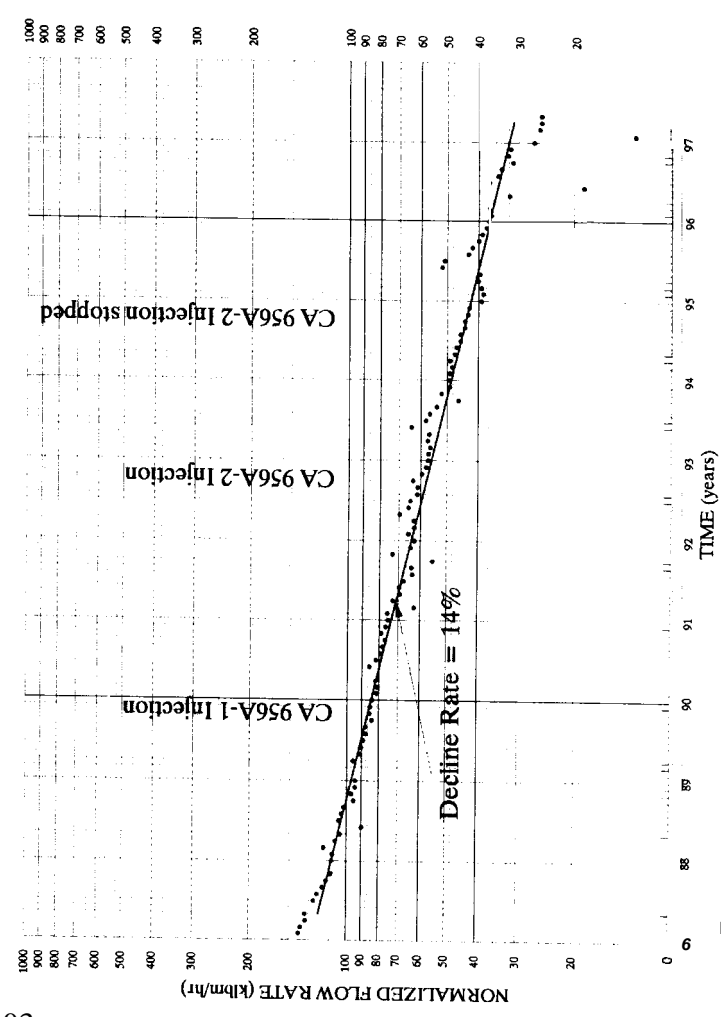


Figure 4. Normalized flow of CA 958-7 at 110 psig wellhead pressure versus time

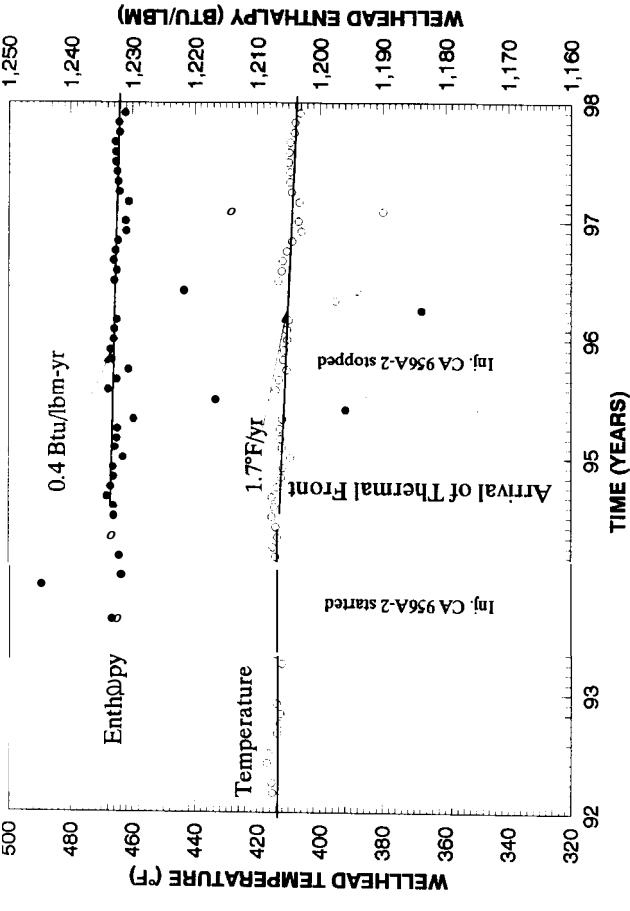


Figure 3. Temporal variation in wellhead temperature and enthalpy for CA 958-3

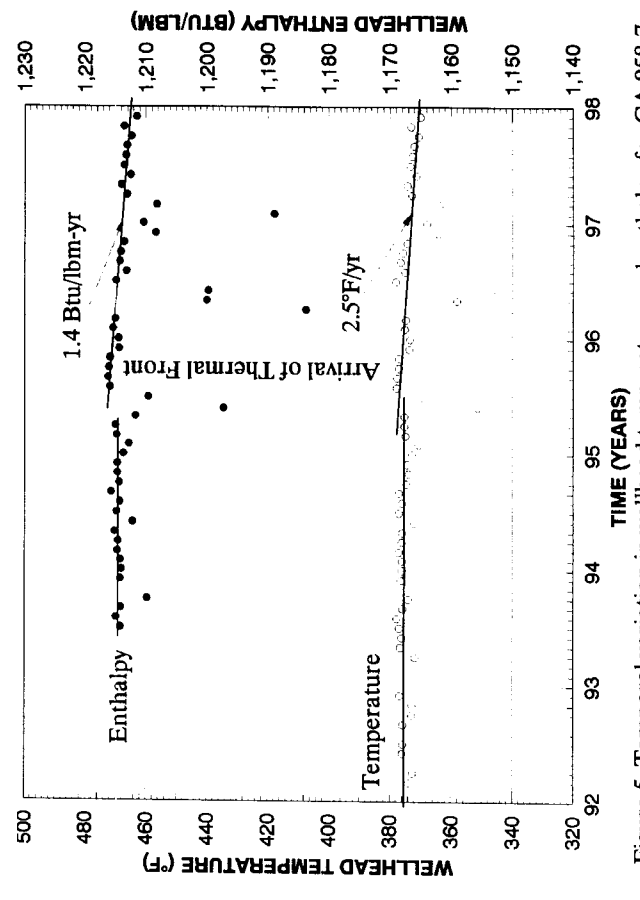


Figure 5. Temporal variation in wellhead temperature and enthalpy for CA 958-7

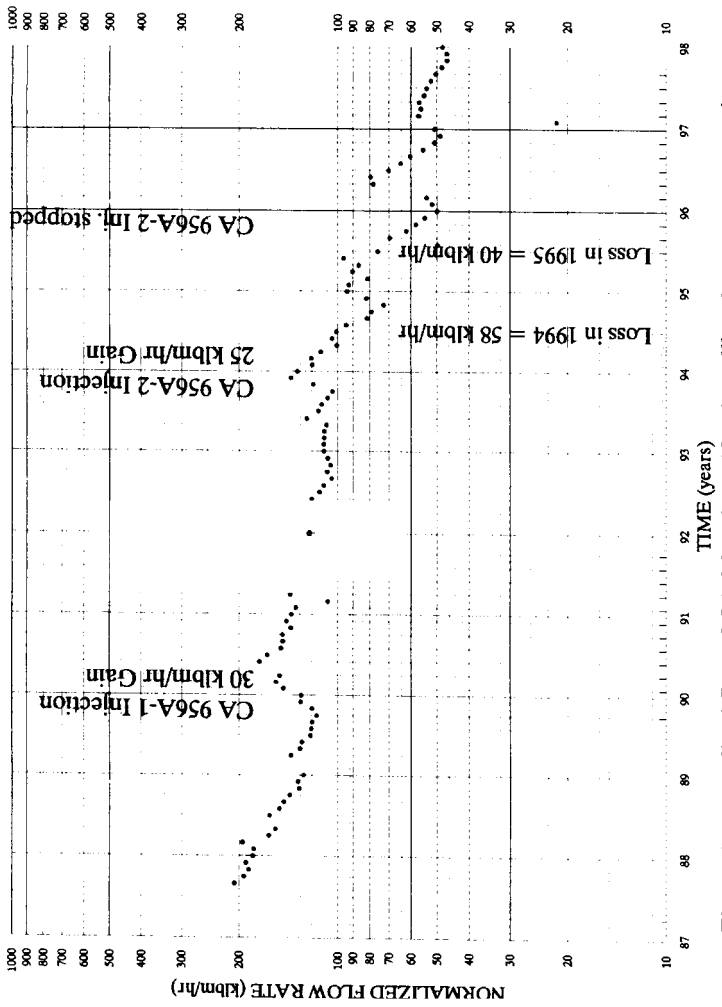


Figure 7. Normalized flow of CA 958-14 at 110 psig wellhead pressure versus time

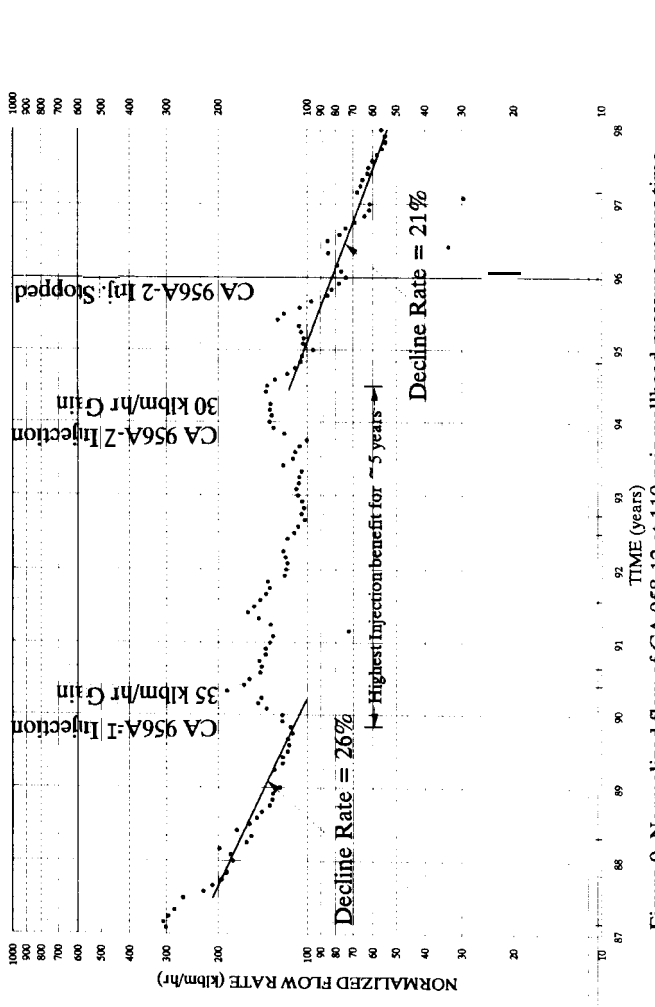


Figure 9. Normalized flow of CA 958-12 at 110 psig wellhead pressure versus time

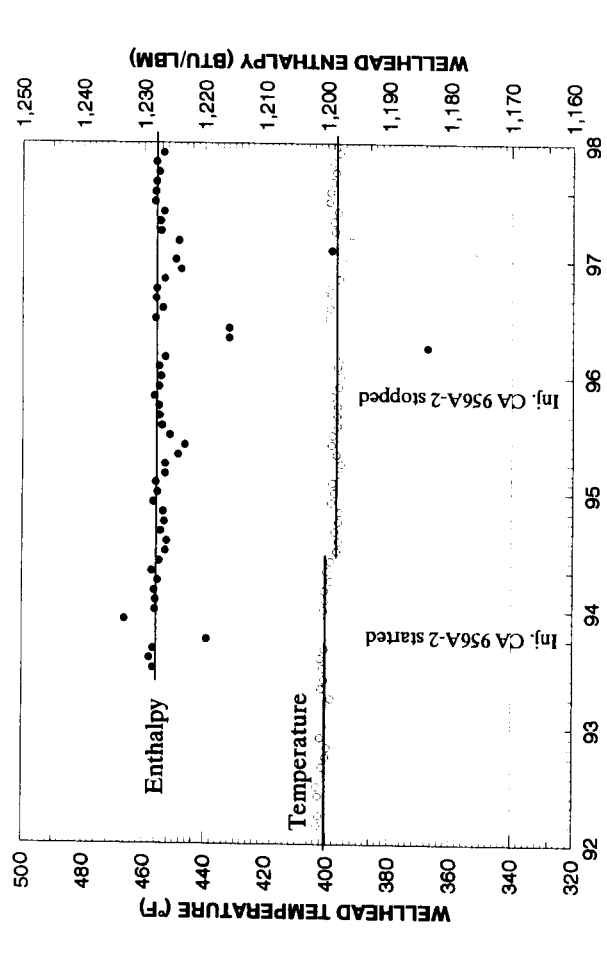


Figure 6. Temporal variation in wellhead temperature and enthalpy for D&V-2

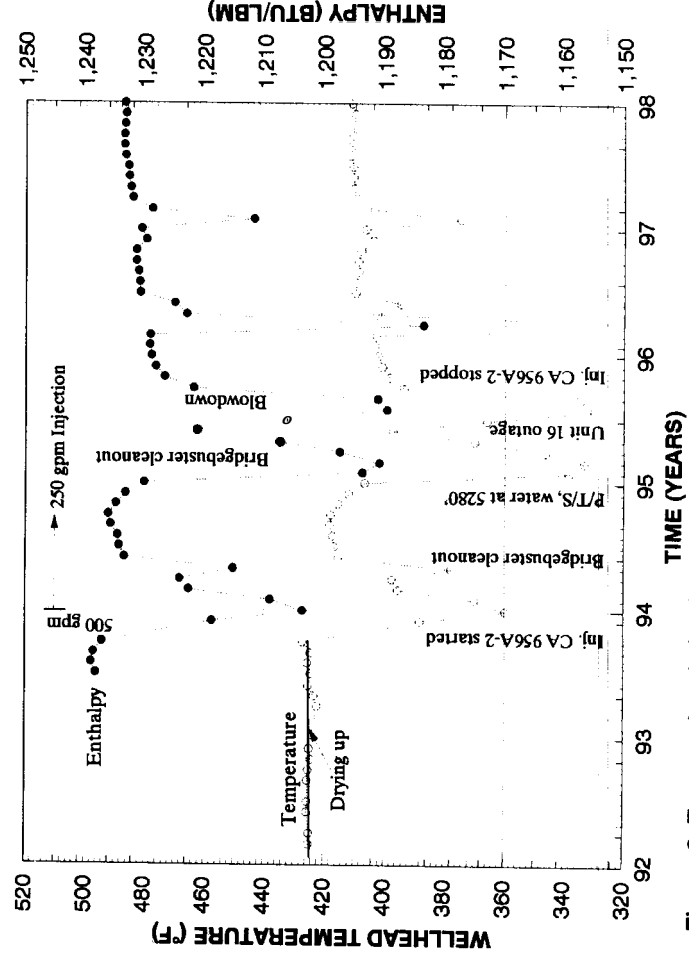


Figure 8. Temporal variation in wellhead temperature and enthalpy for CA 958-14

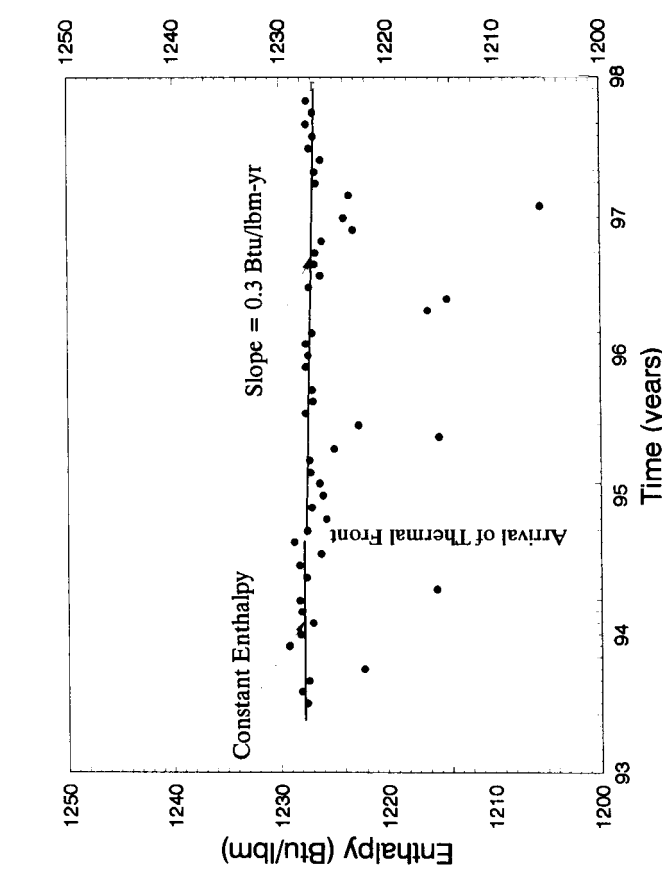


Figure 11. Effect of CA 956A-1 injection on the enthalpy of nine nearby wells

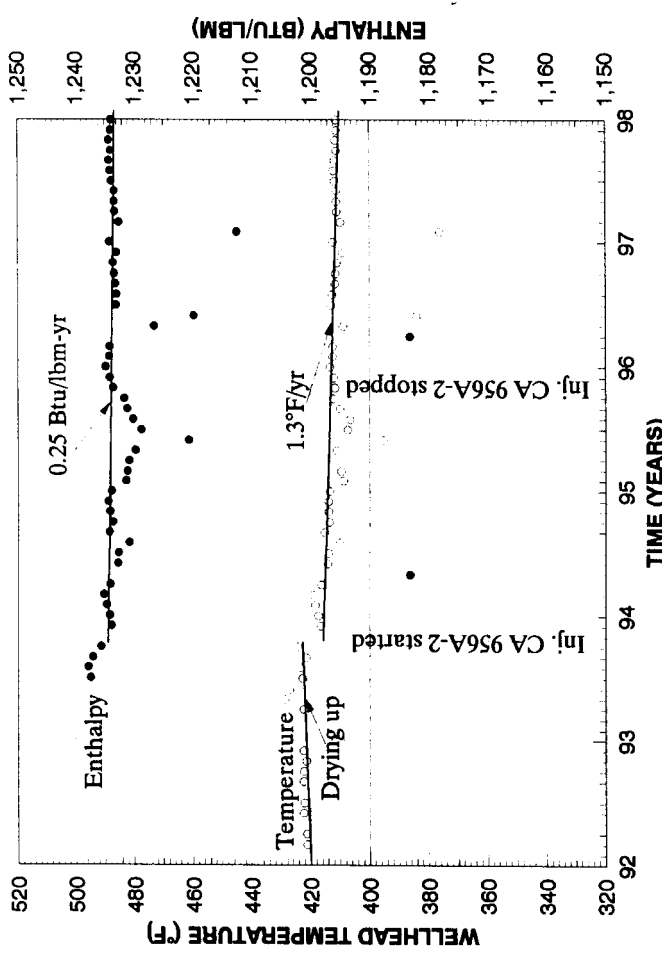


Figure 10. Temporal variation in wellhead temperature and enthalpy for CA 958-12

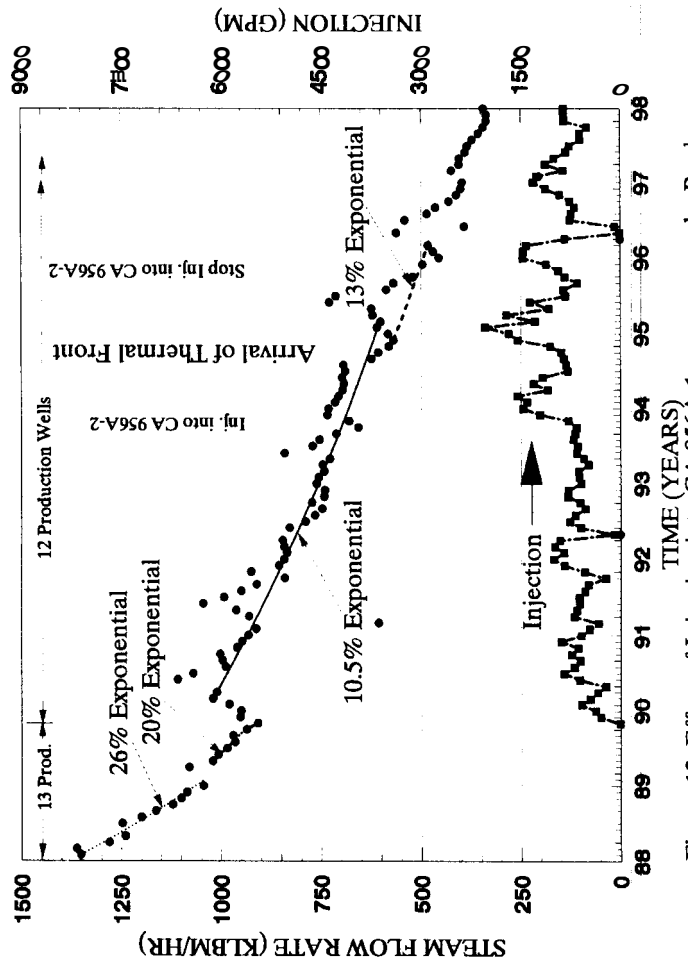


Figure 12. Effect of Injection into CA 956A-1 on some nearby Producers