FOSSIL ENERGY

DOE/SF/10761-3

FIELD DEMONSTRATION OF THE CONVENTIONAL STEAM DRIVE PROCESS WITH ANCILLARY MATERIALS

Final Report

Work Performed for the Department of Energy
Under Contract No. DE-FC03-79SF10761

Date Published—June 1983

CLD Group, Inc.
Ventura, California

U. S. DEPARTMENT OF ENERGY

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Final Report

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Section 1

CONTRACT PERFORMANCE, LABORATORY AND FIELD TESTS

I. INTRODUCTION

CLD Group, Inc. entered into a contract with the U. S. Department of Energy in October 1979, to test additives with steam drive. The project was comprised of basic laboratory R&D supplemented by five field tests. The purpose of this research sponsored by the U.S. Department of Energy and three industrial partners -- Santa Fe Energy, Texaco, and Conoco -- was to evaluate the potential of chemicals for increasing the sweep of steam drive and displacement of oil. The project was conducted in four phases:

- PHASE 1: Preparation and Laboratory Work. The first phase involved laboratory work on chemical screening, foam system development (which was thought to be important in achieving the objective), and bench testing of alternate emplacement techniques.

- PHASE 2: Field Tests. The second phase consisted of four small field tests using various embodiments of the process in different reservoir settings.

- PHASE 3: Verification Field Test. The third phase was a longer term verification field test to assess the process under standard field operating conditions.

- PHASE 4: Data Collection and Analyses. The results of the laboratory and field tests were reported regularly in U.S. Department of Energy reports and other technical publications.

The first year of the contract was spent screening surfactants for their ability to produced stabilized foams at elevated temperatures, conducting injection tests in the laboratory, and preparing for the field tests.

This laboratory work was reported in SPE/DOE Paper 9777 (April 1981), in the First Annual Repoort to the Department of Energy (1980), DOE/SF 10761-1, and in the Journal of Petroleum Technology (July 1982).

The next two years were spent on five field tests in California. The field test locations were chosen to address two major technical problems encountered in steam drive operations; namely, the excessive channeling of steam through "thief" zones, and the progressive increase in steam flow through oil-depleted, already swept zones.

The second year involved the completion of two field tests; one in the Midway-Sunset Field, and one in the Cat Canyon field. This field work was reported in the Second Annual Report to the Department of Energy (1981), DOE/SF 1076-2.

The third year was spent completing the remaining three field tests -- two in the San Ardo Field, and the verification test in the Midway-Sunset Field.

This Final Report completes the analysis of the two initial field tests and discusses the remaining three tests. The report consists of two parts. The first part summarizes the result of laboratory tests and presents the five field tests and their results. The second part analyzes the combined performance of the two tests at the Midway-Sunset Field.

II. BACKGROUND

Two generic problems lower the efficiency of steam drive, the most widely used enhanced recovery process for heavy oils. First, as the oil in the steam zone is depleted, the pressure gradient decreases, assuming the same mass flow of steam is maintained. Despite adequate heat transfer, the production of oil progressively decreases, the oil-steam ratio increases, and the economics deteriorate. Second, because of major differences in the kinematic viscosities of steam and the heated crude, the injected steam vapor is an inherently inefficient carrier or displacement agent for crude oil.

In problem reservoirs, the steam may break through to the producing wells through a streak of high permeability, a zone of high water saturation, or fractures isolated from the oil column by lithology. The oil-steam ratio then decreases because much of the injected steam merely circulates through the thief zone.

The purpose of injecting ancillary materials is to lower the steam mobility in the depleted oil zone, or in the thief zone, both of which are highly receptive to steam, and to improve the capacity of the flowing steam to carry crude oil. Because of the wide variety of reservoir settings, a large number of tests are required to demonstrate the applicability of the process in different lithologies and under different operating practices.

III. LABORATORY TESTING

The initial task under this contract consisted of screening chemical additives in the laboratory using a five-step procedure:

Step 1. Static Foam Tests. Commercially available chemicals were screened to evaluate their foaming ability using the Chevron blender test and the Stanford refluxing test.

Step 2. Laboratory Sandpack Tests. Selected chemicals from Step 1 were laboratory tested in a short sandpack at ambient temperatures to examine their effectiveness at reducing permeability.

Step 3. Corrosion Inhibitor Studies. Chevron type stirrer tests were undertaken to determine the effects of oxygen corrosion inhibitors on the stability of the selected chemicals.

Step 4. Laboratory Scale Steam Sandpack Tests. A series of high temperature sandpack tests were run to establish the ability of the chemical systems to develop resistance to flow at elevated temperatures, and the most effective injection method of chemicals, steam, and noncondensible gas.

Step 5. 16-Foot Sandpack Tests. Finally, the systems were tested using a high pressure, sandpacked 16-foot core connected to a field-operated steam generator.

These laboratory tests led to selection of chemical and the initial design of the chemical system to be used in the five field tests.

In addition, the laboratory work led to a significant revision in the process. The original concept of the process was based on emplacing a foam of sufficient stability and resistance to completely block the steam channel. However, it was established that if this occurred, the displacement of oil would cease, since permissible injection pressures would not allow the frontal displacement of heavy oil. Thus, the concept was revised to allow only partial blocking and thereby increase the efficiency of the steam in a mature steam drive.

The laboratory tests also showed that the additives had to contain non-condensable gas, which must be co-injected or injected alternating with steam.

The five field tests and their results are discussed individually in the next chapter.

IV. FIELD TESTS

A. INTRODUCTION AND SUMMARY

Five field tests were designed to extend the laboratory-derived results under instrumented and controlled conditions. Radioactive tracers, casing head gas analyses, temperature surveys, and water cuts were used to provide analytic support to the interpretation of the field tests. The five tests also examined the use of steam with additives under different reservoir settings.

- Field Test #1 was a low concentration chemical slug with air injection test in the Midway-Sunset Field; the purpose of the test was to determine whether the additives could increase the oil-steam ratio and oil production from a massive reservoir sand in which the oil-steam ratio had reached an uneconomic limit and the oil recovery efficiency had approached 50%. A significant incremental oil recovery (65,000 barrels) and improvements in the oil-steam ratio was obtained.

- Field Test #2 was a combination slug and continuous chemical injection test in the Cat Canyon Field; the purpose of this test was to examine the capacity of the chemical and nitrogen additive system to block a massive steam channel in a deep, hot, and highly viscous reservoir. Although incremental recovery was minor, the test succeeded in decreasing the water cut in the key well.

- Field Test #3 was a verification test involving the injection of higher concentrated additives and air to re-establish oil production and achieve a major increase in recovery efficiency in the same pattern as used for Field Test #1. The eight month test was very successful and recovered an additional 46,000 barrels of oil.

- Field Test #4 was a slug test using nitrogen as the inert spreader-gas in the San Ardo Field; the purpose of this test was to determine the effectiveness of the additive system in a reservoir from which over 60% of the crude had been recovered and a clearly defined large zone of depletion had been established at the top of the reservoir. Although the additional oil recovery was minor at 3,500 barrels, a definite response was measured in the oil-steam ratio and in the diversion of steam.

- Field Test #5 was an expansion of Test #4 using continuous injection of chemical and nitrogen. This test succeeded in receiving an additional 21,500 barrels of oil.

The results from each of these five field tests are presented below. Additional discussion of the two Midway-Sunset tests analyzed together are provided in Section 2 of this report.

B. TEST #1. MIDWAY-SUNSET FIELD

A 12-month pilot test of steam with additives was completed in October 1981 in a heavy oil field, the Midway-Sunset Field, Kern County, California, on a lease belonging to Santa Fe Energy. The pilot pattern is 590-21N, located in T31S R22E, Section 21, as shown on Figure 1-1. Additional detail on Section 21 and the surrounding area is provided on Figure 1-2.

The purpose of the test was to determine whether chemical additives could revive a steam drive pattern at the end of its economic life. Injection of a high temperature resistant chemical and compressed air started in November 1980 and continued through April 1981. Monitoring of performance continued through October 1981.

Figure 1-1

LOCATION MAP: MIDWAY-SUNSET OIL FIELD

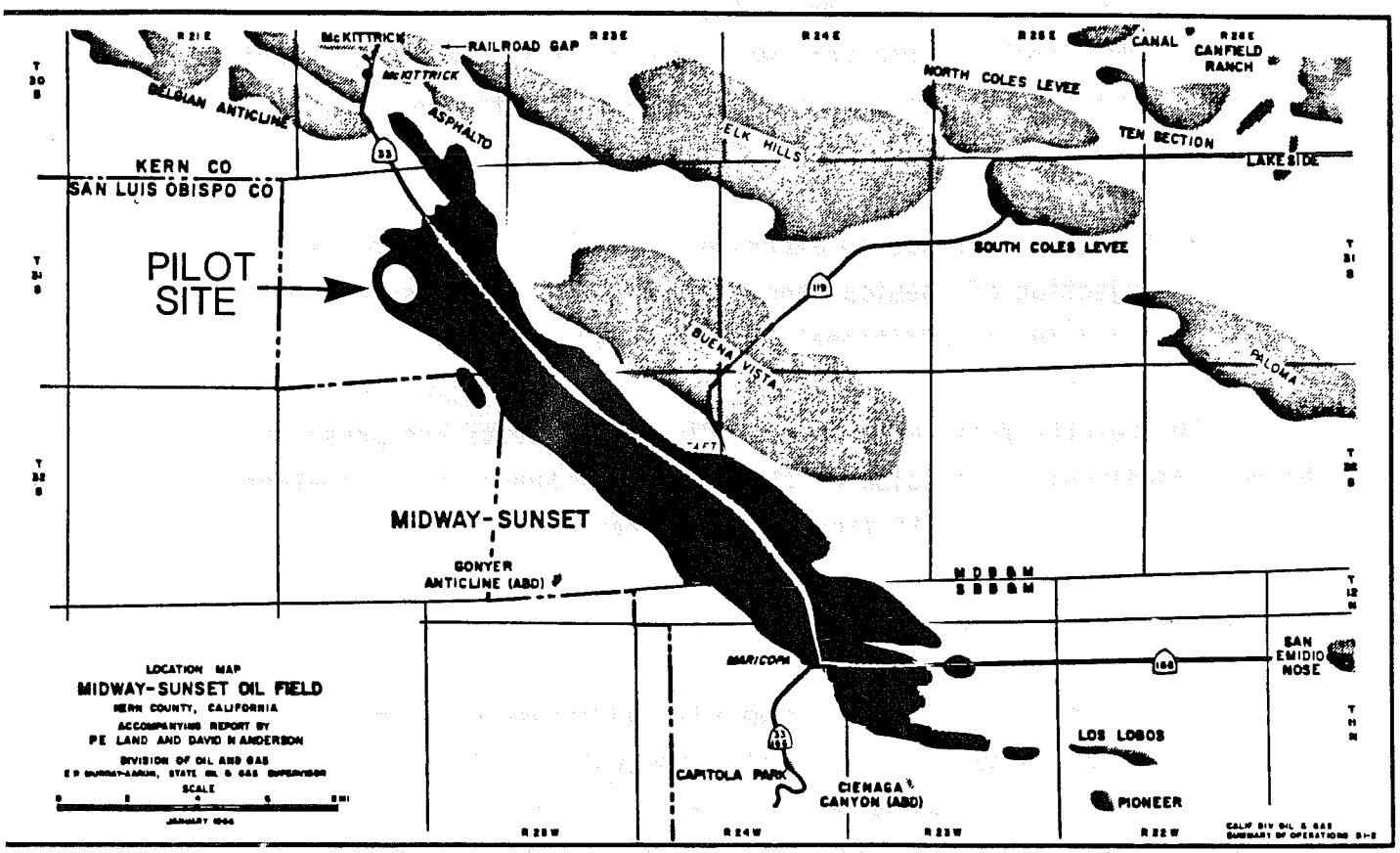
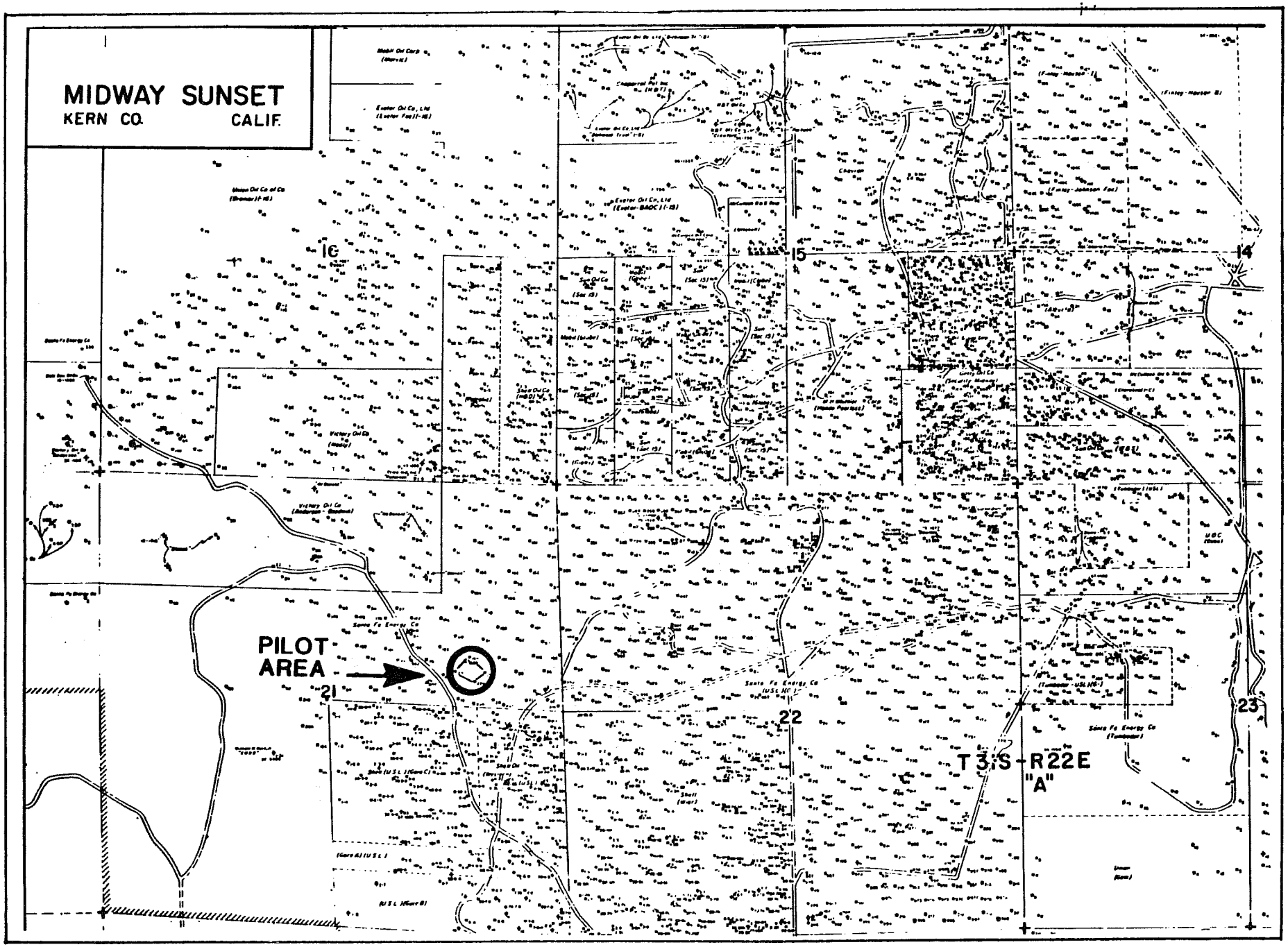


Figure 1-2

SITE OF PILOT: MIDWAY-SUNSET FIELD



ADAPTED FROM: CALIFORNIA DIVISION OF OIL AND GAS MAP

A plan view of the primary test area, injection well 590 and the four pattern producers are shown on Figure 1-3. The target formation, the "O" and "P" sands of the Spellacy formation, and the considerable reservoir dip are shown on the cross-section on Figure 1-4.

Steam soak was initiated in the pattern in late 1970 and a steam drive in 1972. The pattern had reached its economic limit by 1979, when CLD and Santa Fe concluded an agreement to conduct a steam with additives pilot test. The history of oil production, steam injection, and the oil-steam ratio in Pattern 590-21 are shown on Figures 1-5 and 1-6. The reservoir properties of this pattern are shown on Table 1-1.

The chemical and gas injection procedure in Pattern 590-21 is summarized below. This injection method is based on the prior laboratory and field testing and the equipment capacity.

- A slug of ten to twenty barrels of diluted 13% by volume (6% active) surfactant solution was injected into the flowing steam;

- The steam injection was stopped and air was injected at a rate of 17,000 scf/hr (maximum rate of compressor), for a period of one to two hours;

- Steam injection was then resumed for about four days.

The above injection of chemical and air was repeated until injection was terminated. However, initial operating problems and the irregular availability of steam reduced the amount of chemical and air injected during the first three months.

During the test, a total of 22,000 pounds of high temperature resistant chemical (Thermofoam BW-D), 2,000,000 Scf of air, and 180,000 barrels of steam were injected.

Figure 1-3

STEAM DRIVE PATTERN 590-21 WELLS

(MIDWAY-SUNSET OIL FIELD)

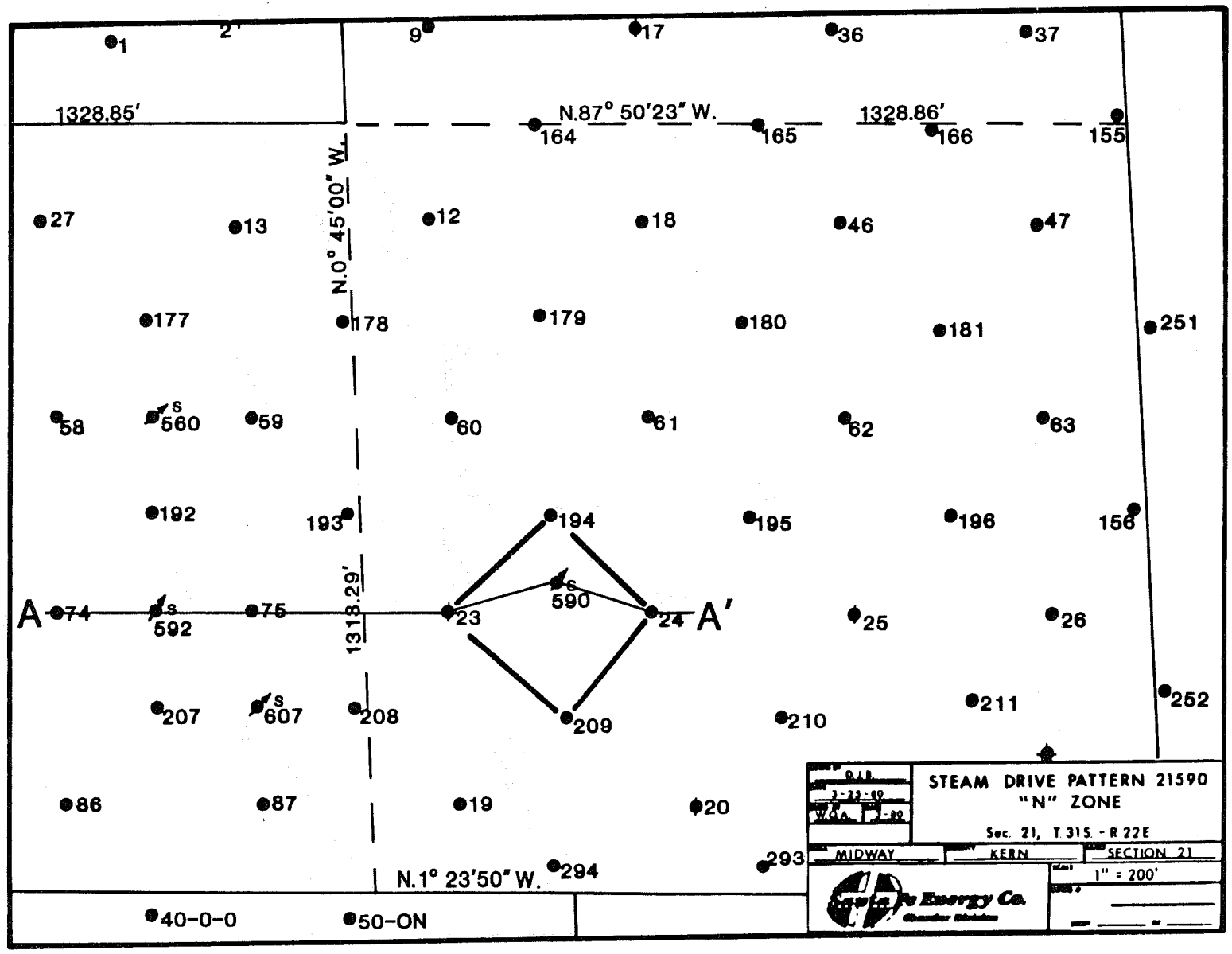


Figure 1-4
CROSS-SECTION OF PATTERN 590-21

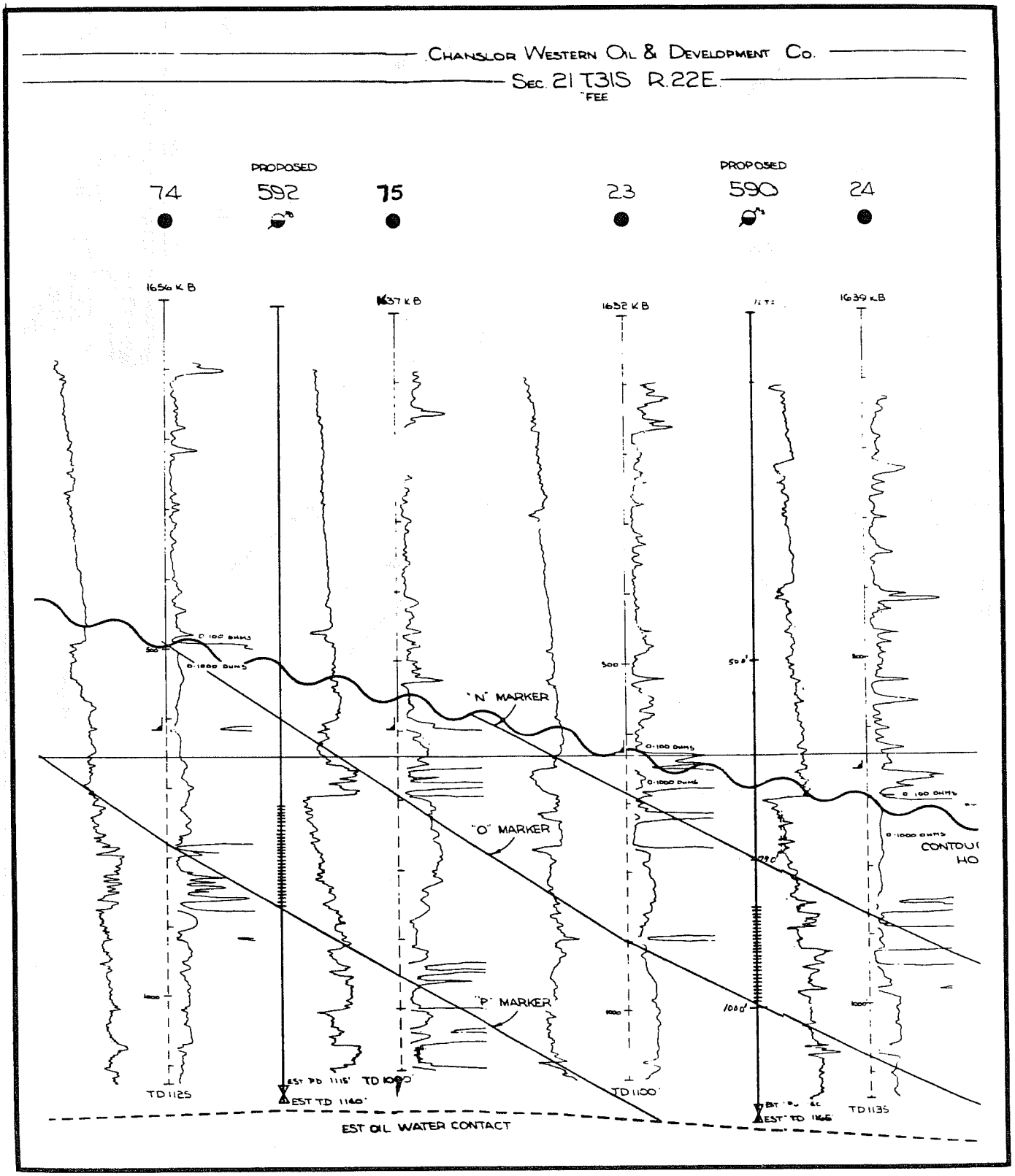
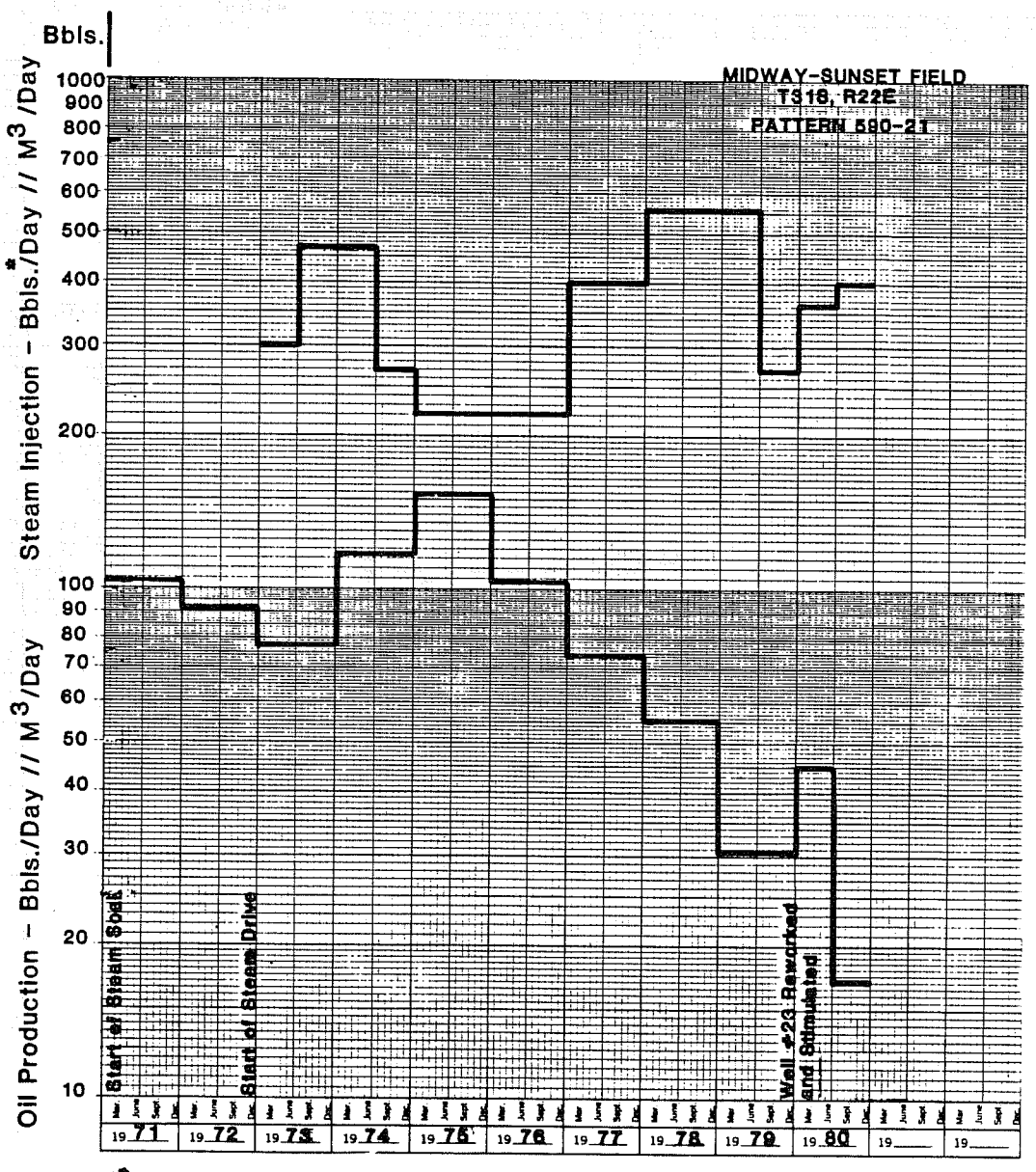


Figure 1-5

HISTORY OF OIL PRODUCTION AND STEAM INJECTION

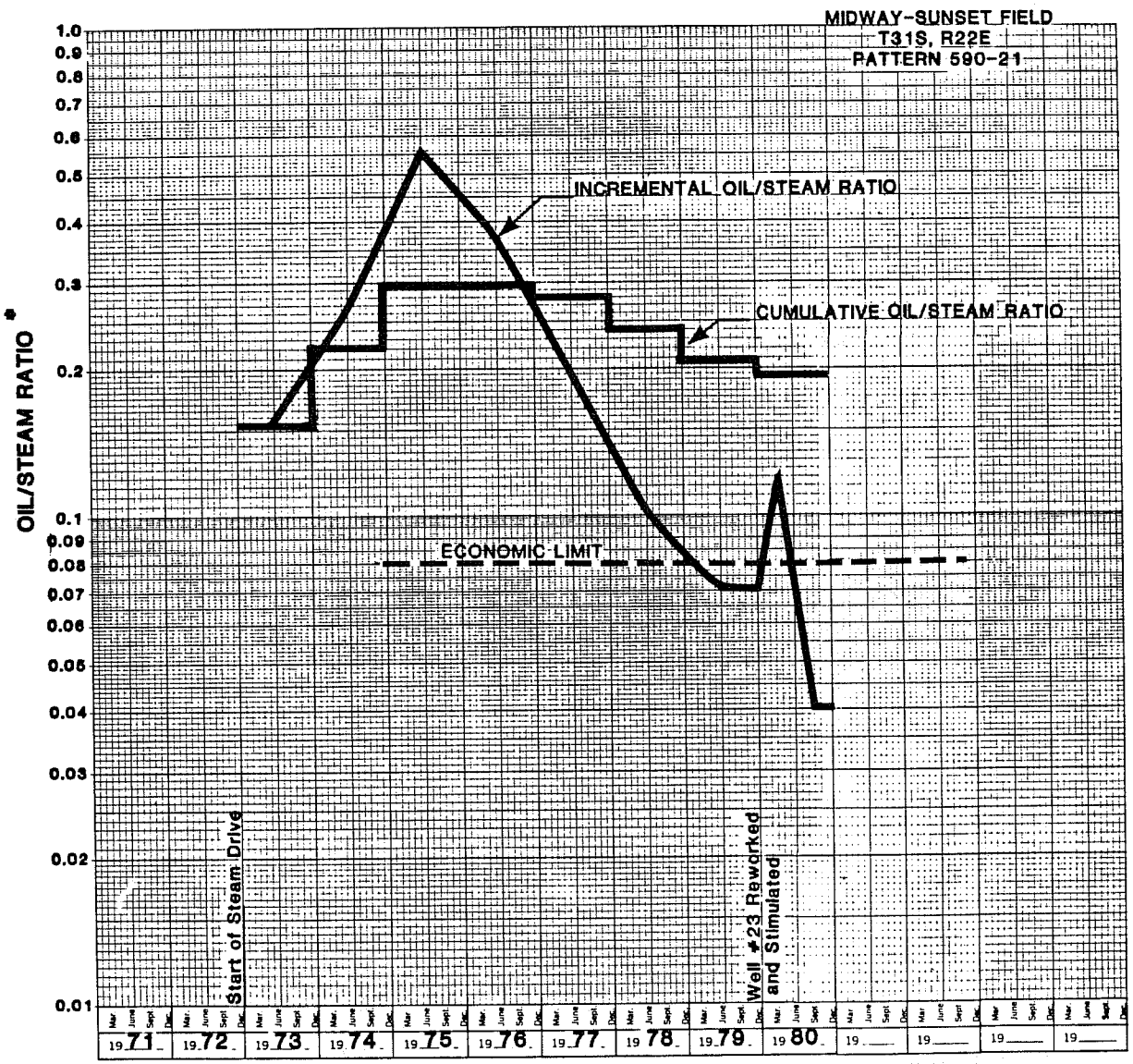
(PATTERN 590-21)



* PLUS FROM 50 TO 80 BARRELS PER DAY OF STEAM SOAK THROUGH 1976

Figure 1-6

INCREMENTAL AND CUMULATIVE OIL-STEAM RATIO
(PATTERN 590-21)



* OIL/STEAM RATIO INCLUDES STIMULATION STARTING IN 1973

Table 1-1

BASIC DATA FOR PATTERN 590-21

MIDWAY-SUNSET OIL FIELD

	ENGLISH UNITS	METRIC UNITS
DEPTH	1,000 FEET	305 M
OIL GRAVITY	11° API	0.993 G/CM^3
AREA	1.50 ACRES	6.070 M^2
GROSS PAY	500 FEET	152 M
NET PAY	400 FEET	122 M
POROSITY	28%	
ORIGINAL OIL SATURATION	53%	
ORIGINAL OIL CONTENT	1,100 B/AF	0.14 M^3/M^2
FORMATION VOLUME FACTOR	1.05	
PERMEABILITY	2,000 MD.	
ORIGINAL OIL IN PLACE	660,000 BARRELS	104,933 M^3
PRIOR OIL RECOVERY:		
- PRIMARY DEPLETION	22,000 BBLS. (EST.)	3,498 M^3
- STEAM SOAK/DRIVE	308,000 BBLS.*	48,969 M^3
- % RECOVERY	~50%	
OIL REMAINING IN PATTERN AT START OF TEST	330,000 BARRELS	52,466 M^3

* SOME PORTION OF THIS OIL MAY BE DUE TO DRAINAGE FROM OUTSIDE OF THE PATTERN AREA

A significant improvement in performance occurred during the test. The three-month moving average of oil and water production and the oil-steam ratio from Pattern 590-21 through the first test are shown on Figure 1-7. The pattern started responding in February 1981, three months after injection of air and chemicals started. After the injection was terminated in April 1981, the three-month average pattern performance continued to show a response through October 1981, when the test was stopped.

The improvement in performance is summarized below:

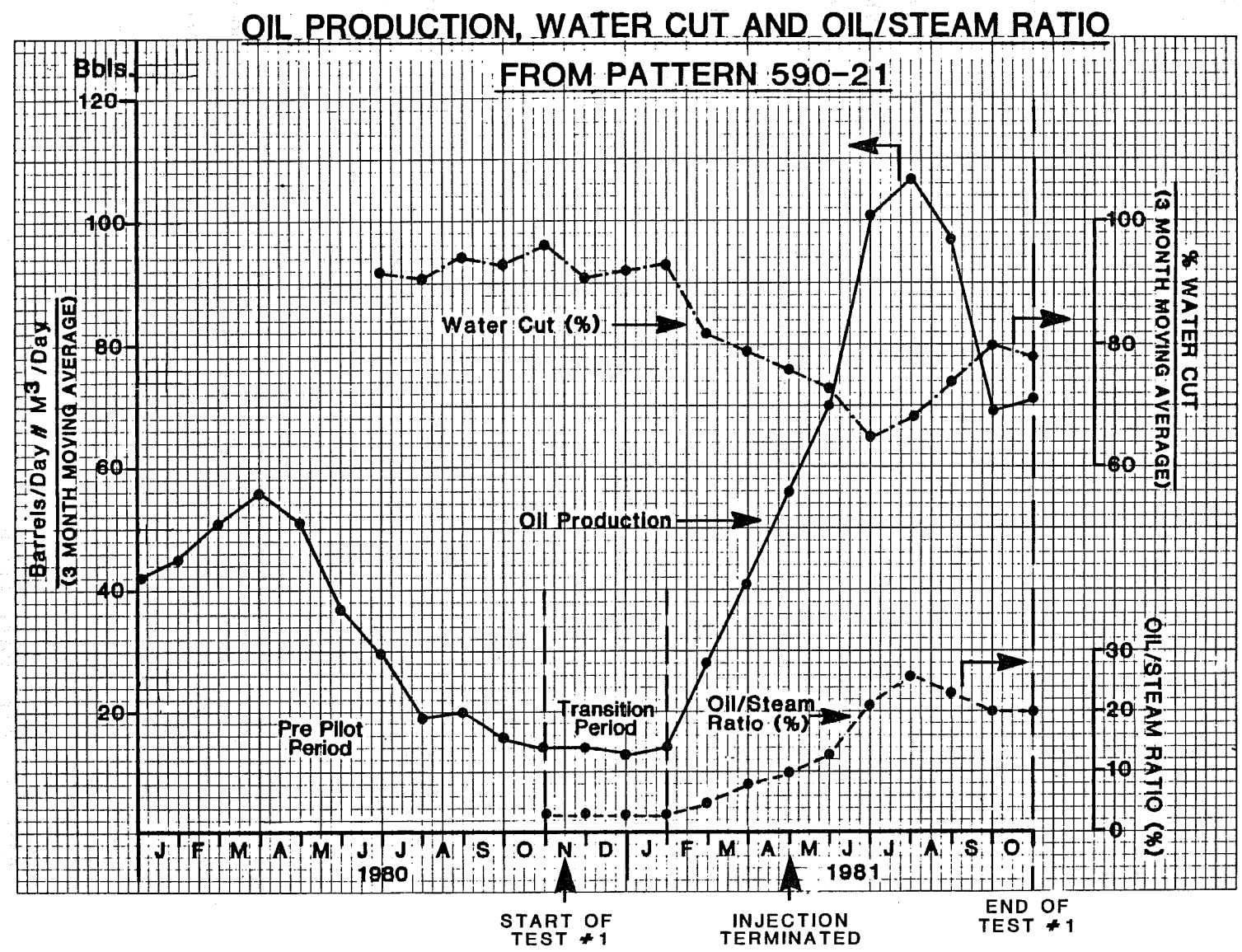
- Oil production in the pilot area increased four-fold, from a six-month average of 18 barrels per day prior to the test in 1980, to an average of 72 barrels per day from February through October 1981; recovery reached a peak of 144 barrels per day in July 1981. During the 9-month period, February through October, a total of 20,000 barrels of oil were produced from Pattern 590-21.

- The oil-steam ratio, the key measure of economic performance, increased five-fold from a base of 0.04 in the last six months of 1980 (the pre-test base year) to over 0.20 for the last six months of the test (May-October, 1981). Overall, the oil-steam ratio, for continuous steam injection into Pattern 590-21, averaged 0.13 for February through October, 1981.

- The oil-cut in Pattern 590-21, an important measure of steam efficiency in an unconfined pattern, improved steadily from a base of 6% (for the last six months of 1980) to 25% for February through October, 1981.

- Deterioration in the pattern performance was first observed in August 1981, three months after injection of chemical and air were terminated; oil production in October 1981, at the end of the pilot test, was 60 barrels per day.

Figure 1-7


OIL PRODUCTION, WATER CUT AND OIL/STEAM RATIO
FROM PATTERN 590-21
Bbls.
Barrels/Day // M3/Day
(3 MONTH MOVING AVERAGE)
120
100
80
60
40
20
Water Cut (%)
Oil Production
Pre Pilot Period
Transition Period
Oil/Steam Ratio (%)
% WATER CUT
(3 MONTH MOVING AVERAGE)
100
80
60
OIL/STEAM RATIO (%)
30
20
10
0
J F M A M J J A S O N D J F M A M J J A S O
1980
1981
START OF TEST #1
INJECTION TERMINATED
END OF TEST #1

The main pattern (Pattern 590-21) and the surrounding second and third ring wells involved in the field test are shown on Figure 1-8. The wells that responded to the test are circled.

Eight second ring and six third ring wells had improvements in the oil-steam ratio and the water cut, as well as the rate of oil production, as shown on Table 1-2 and summarized on the following page.

- The oil-steam ratio for the eight second ring wells increased from 0.27 in 1980 to 0.70 (February-October); similarly, the oil-steam ratio for the six affected third ring wells increased from 0.74 in 1980 to 0.85 (February-October).

- Oil production in the affected second ring of wells increased by 29,000 barrels and in the six third ring of wells by 16,000 (February-October) over the established historical decline curve. The improvement in oil recovery for the second and third ring wells is shown in Figures 1-9 and 1-10.

Overall, approximately 63,000 barrels of incremental oil was produced (February-October, 1981) from Pattern 590-21 and the affected second and third ring wells. On average, 0.35 pound of chemical, 32 scf of air, and 3 barrels of steam were injected per barrel of additional oil produced.

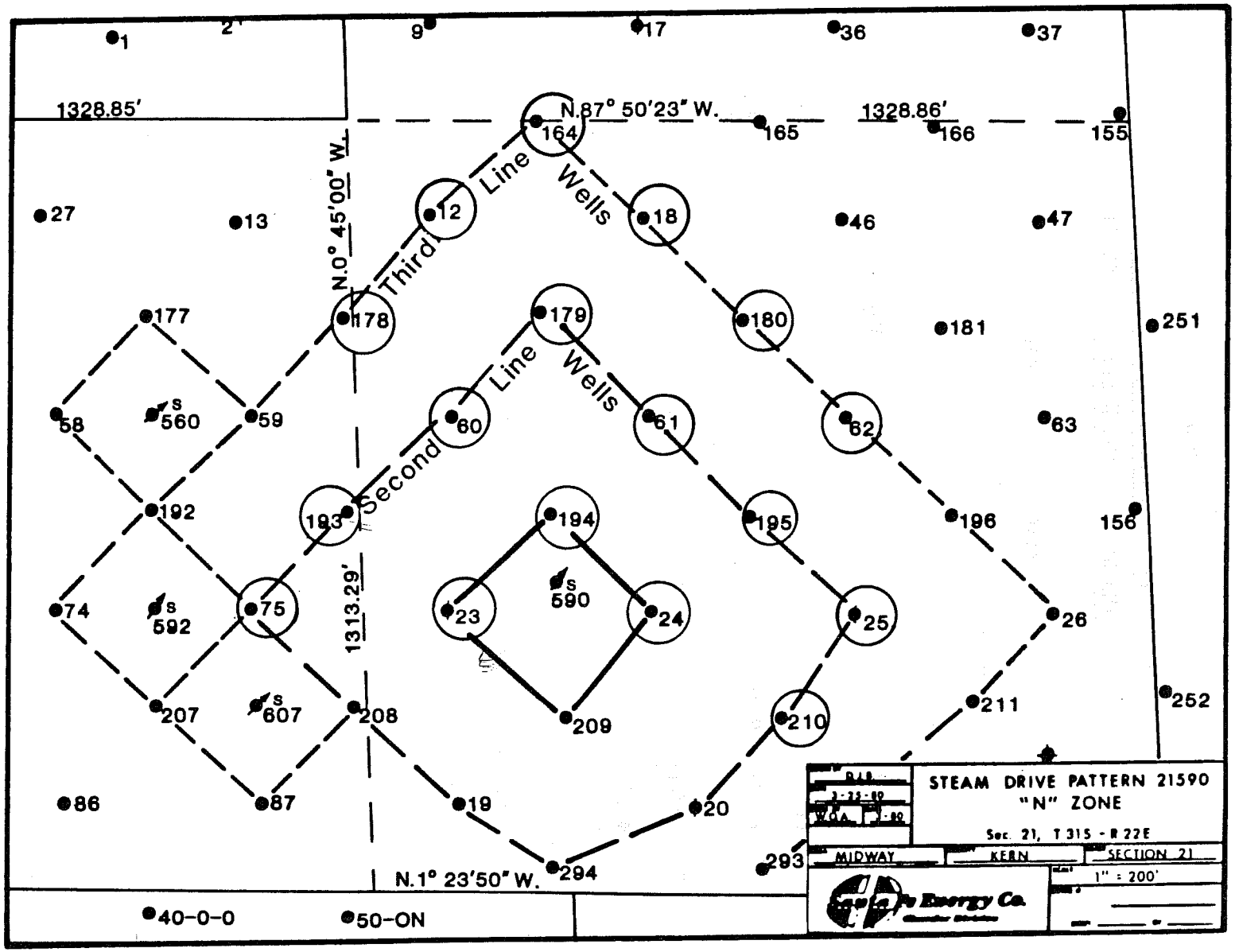
Temperature surveys taken in the key updip well (Well 23) showed a progressively widening steam profile, Figure 1-11. Prior to the test, the steam swept zone was 50 feet in September 1980. During the test, the zone increased to more than 250 feet by the end of the test in August 1981.

C. TEST #2. CAT CANYON FIELD

The second test was a six-week injection test in a deep, hot formation of the Cat Canyon Field with very viscous oil. The location of

Figure 1-8

STEAM DRIVE PATTERN 590-21 "N" ZONE



164 Wells with Response to Steam with Additives.

TABLE 1-2

PERFORMANCE OF PATTERN 590-21

AND SURROUNDING WELLS - FIRST TEST

	Pattern 590-21	2nd Ring Wells	3rd Ring Wells
No. of Affected Wells	4	8	6
Oil-Steam Ratio, v/v			
• 1980* Base	0.04	0.27	0.74
• 1981**	0.13	0.70	0.85
Oil Cut, %			
• 1980* Base	6	15	52
• 1981**	25	27	32
Oil Production Rate, B/D			
• 1980* Base	18	49	49
• 1981**	72	147	110

*July-December, 1980

**February-October, 1981

Figure 1-9

OIL PRODUCTION - 2nd RING WELLS

(PATTERN 590-21)

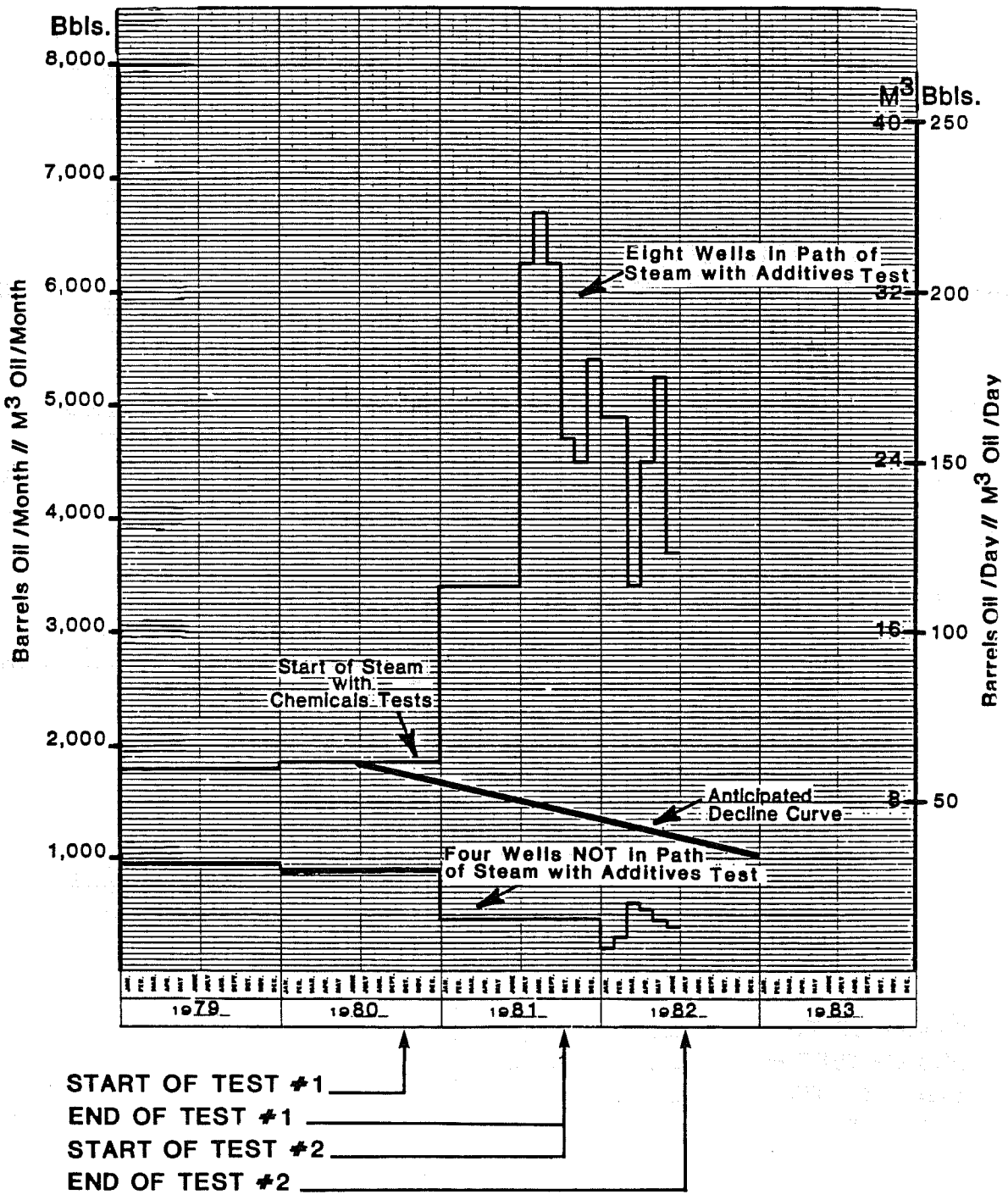


Figure 1-10

OIL PRODUCTION - 3rd RING WELLS

(PATTERN 590-21)

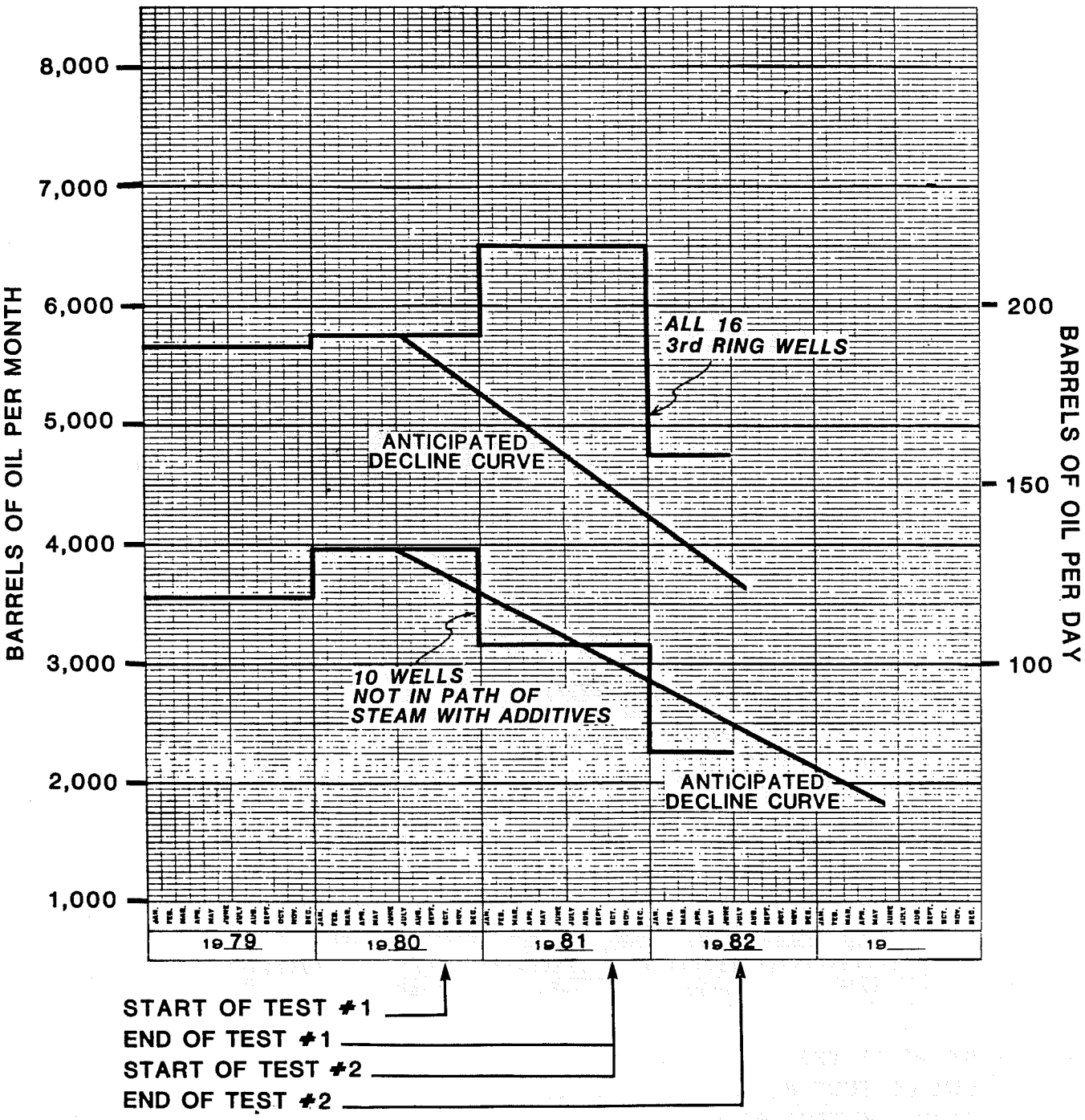


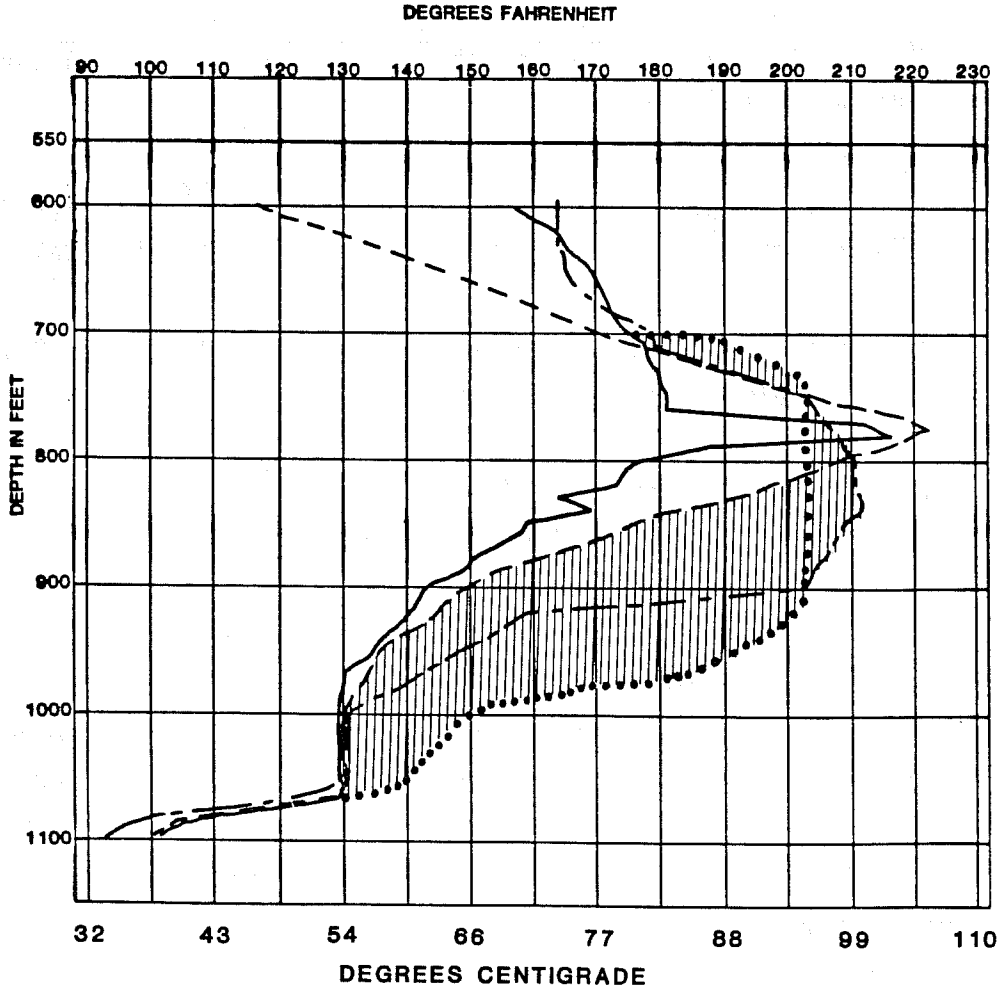
Figure 1-11

TEMPERATURE PROFILE IN PATTERN WELL

(PATTERN 590-21 THROUGH FIRST TEST)

WELL NO: 23-21N
CASING 624
LINER: 607-1100
PERFS: 613-1100
PUMP SHOE DEPTH 1049 KB
BBLS. INJECTED: 5721
GENERATOR NO.: 41
ZERO POINT: K.B.=10
CYCLE NO.: 6

LEGEND
10-19-79
9-30-80
3-19-81
8-10-81



the field and the pilot test site are shown on Figures 1-12 and 1-13. The pilot pattern configuration and cross-sections are shown on Figures 1-14 and 1-15.

The purpose of the test was to determine whether the additives could plug a wide, high permeability channel that provides a direct communication between the injection well and Well 38, the nearest updip production well, Figure 1-14. Radioactive tracer tests indicated that 90% to 95% of the 300 barrels per day of injected steam was going directly to this nearest producer.

This field test represented the most extreme technical limits for using additives with steam drive:

- The steam temperature and pressure were 460°F and 450 to 500 psia, thus testing the thermal limits of the chemical.

- The oil viscosity in the formation was higher, over 25,000 cp at original reservoir conditions.

- The high permeability, "hot region" channel, was estimated to be approximately 30 feet thick and approximately 100 feet above the main oil sand.

The field test was initially scheduled to last four weeks. It was subsequently extended to six weeks between May 1st and mid-June of 1981. During the first three weeks, alternating slugs of chemical and nitrogen were injected. During the next three weeks, chemicals and nitrogen were injected at lower rates, but for a longer time (chemical was injected all night and nitrogen all day).

Figure 1-12

LOCATION MAP: CAT CANYON OIL FIELD

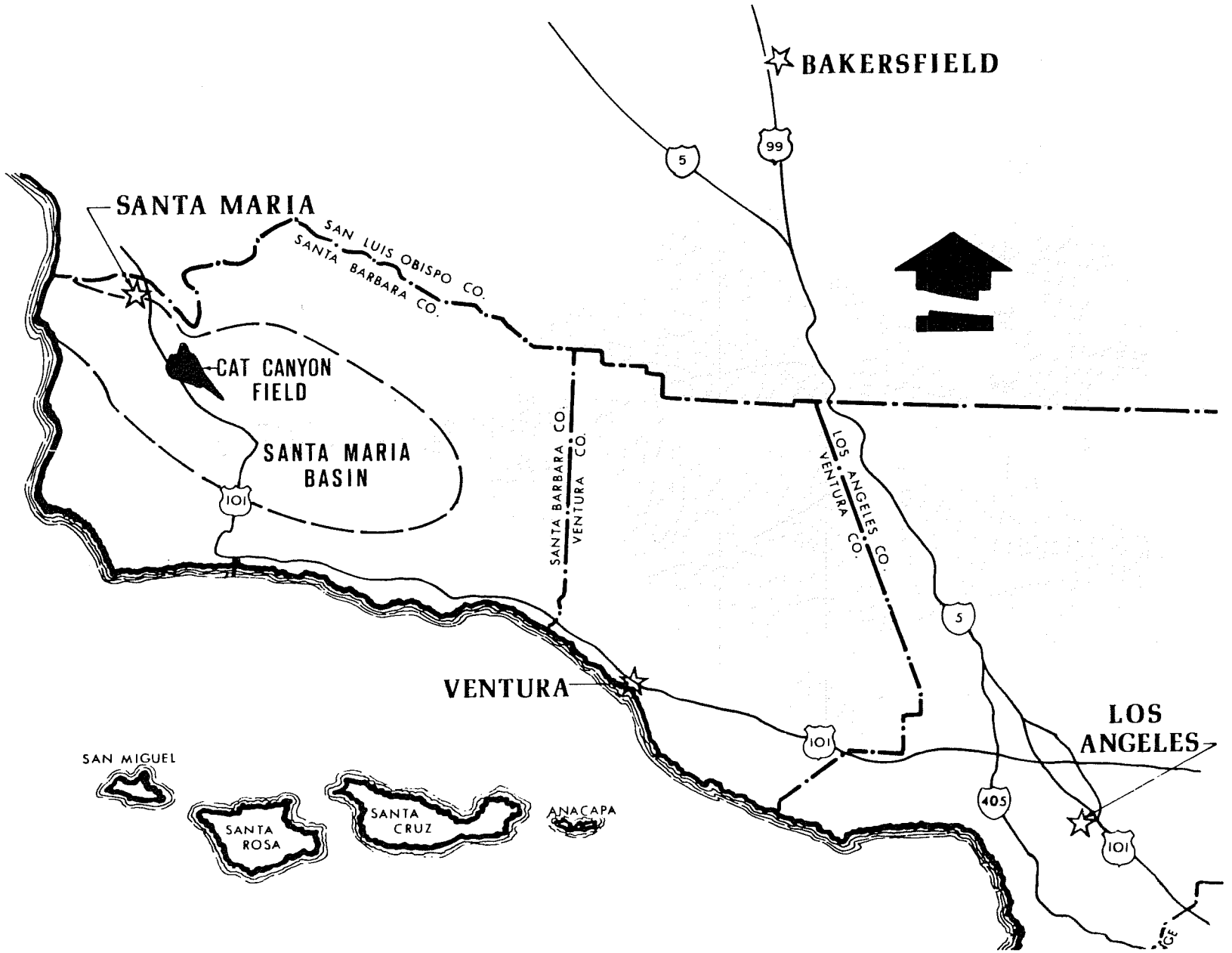
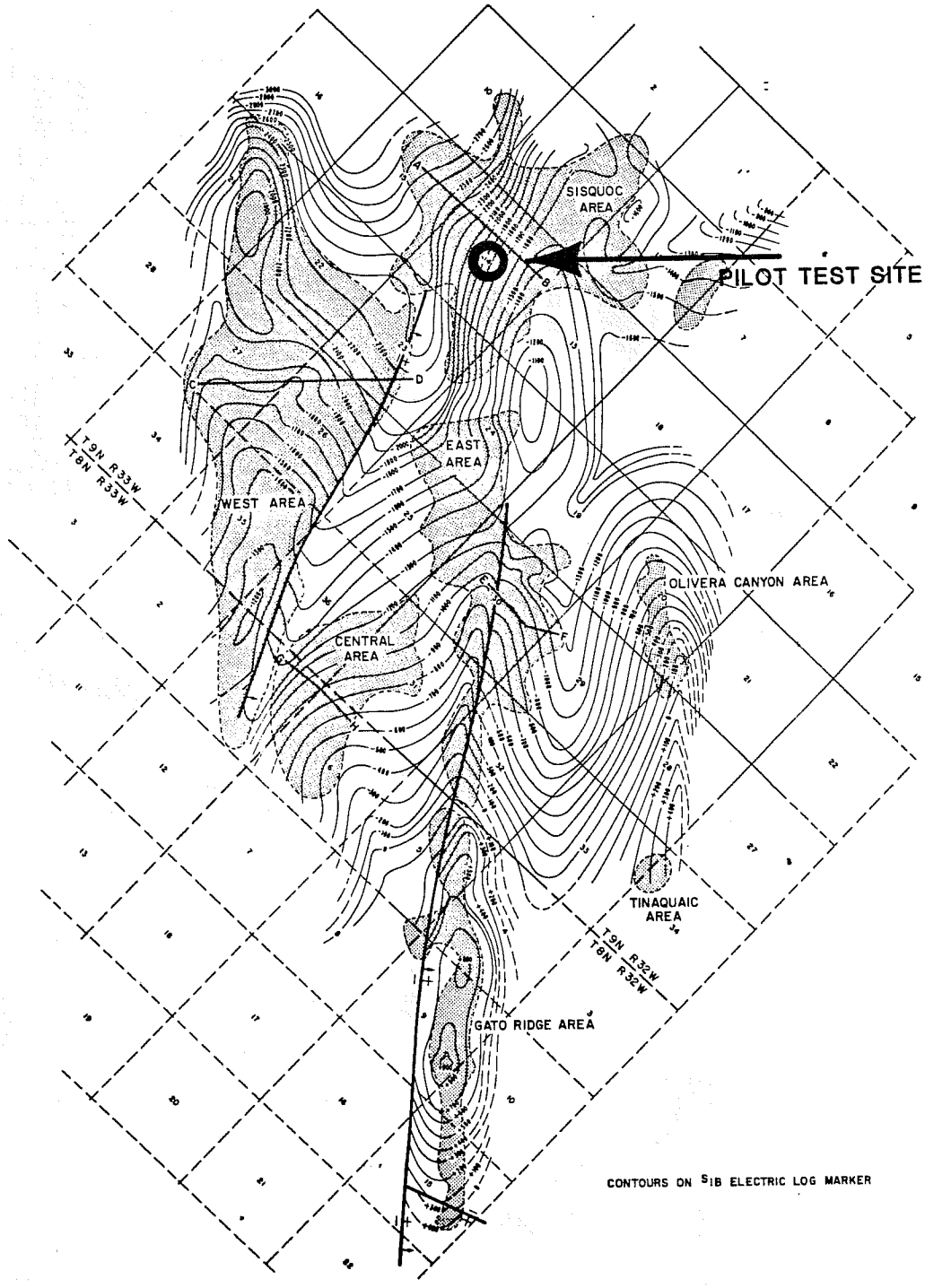


Figure 1-13

STRUCTURE MAP: CAT CANYON OIL FIELD



SOURCE: CALIFORNIA DIVISION OF OIL AND GAS.

Figure 1-14

TEST PATTERN FOR CONOCO FIELD TEST

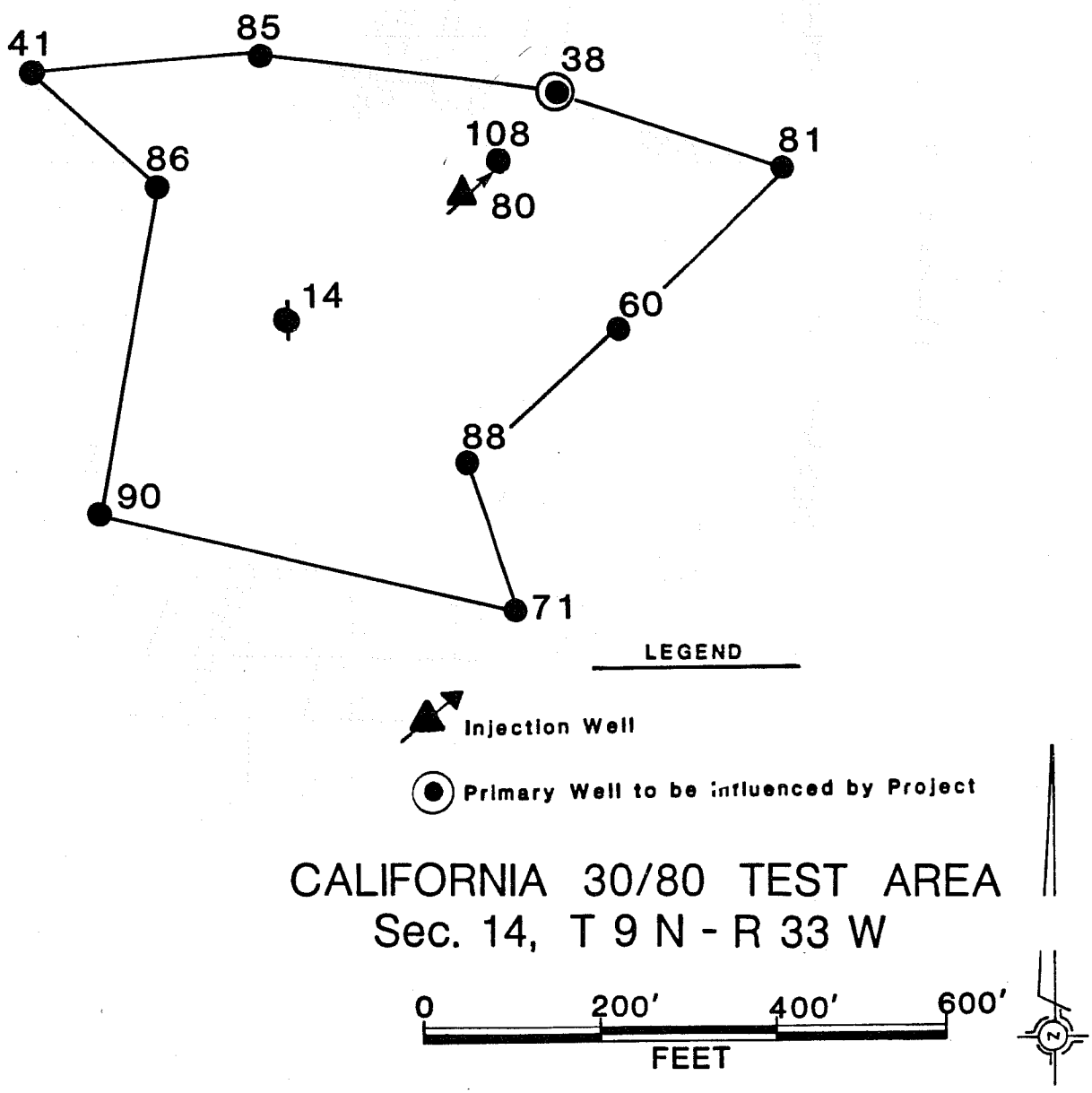
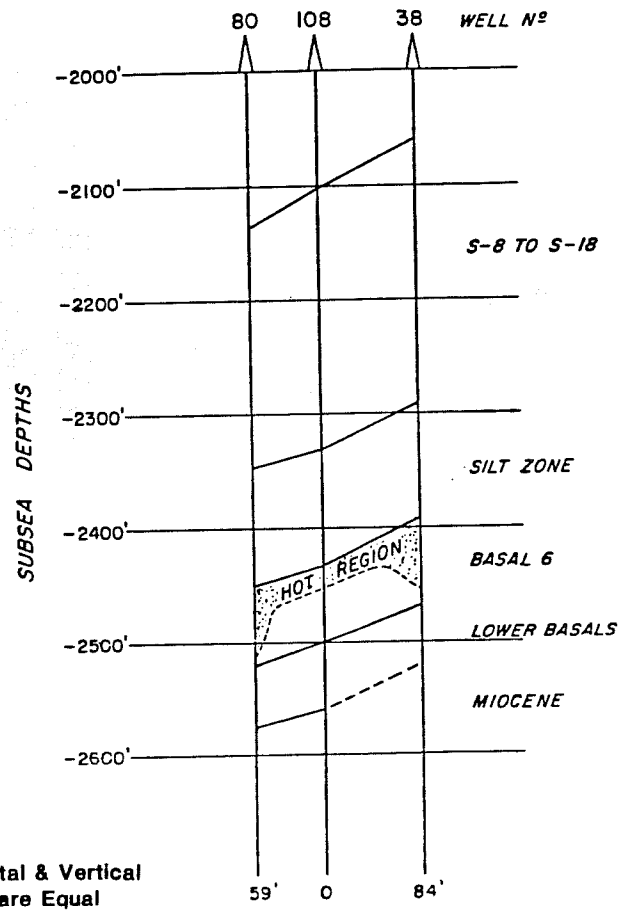


Figure 1-15

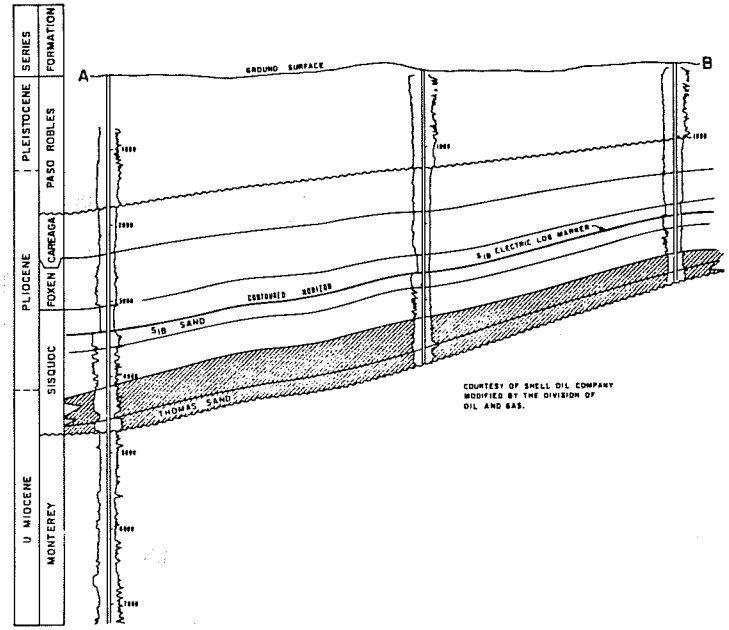
CALIFORNIA 38/80 PROFILE SHOWING HOT ZONE



Horizontal & Vertical Scales are Equal

CROSS-SECTION: CAT CANYON OIL FIELD

(SISQUOC AREA AND WEST AREA)



SOURCE: CALIFORNIA DIVISION OF OIL AND GAS.

The detailed log of chemical and nitrogen injection rate is shown on Table 1-3. For the first two weeks of the test, an average of about 500 pounds of 42% active chemical and 10,000 scf of nitrogen were injected per day as a slug, followed by steam at 300 barrels per day plus 15,000 to 25,000 scf of nitrogen per day. In the third week, the slug of nitrogen was dispensed with and the amount of chemical injected was increased. During the last 3 weeks, chemical injection was increased to about 700 pounds per day, injected at a lower rate, with nitrogen injection fluctuating between 10,000 and 25,000 Scf per day. Overall, a total of 26,900 pounds of chemical and 870 Mcf of nitrogen were injected.

Several changes in the performance of the pattern were measured that indicate some positive response for the test:

- The water cuts in some pattern wells declined over time, as shown in Table 1-4 and Table 1-5. There was a significant change of 12% in the water cut of the key well, California 38; changes in the water cuts of the other wells may have been due to shut-in of offset steam soaks.

- Initial data indicated an increase in the injection pressure, from 440 to about 550 psig during the six-week injection period, while the steam injection rate was maintained at 300 B/D. Since temperature data did not corroborate this change in pressure, the observed changes in pressure may have been due to faulty pressure gauges.

Overall, in spite of certain positive indications, it does not appear that the injection of the chemical and inert gas was able to effectively block the large steam channel above the oil column.

D. TEST #3. MIDWAY-SUNSET FIELD

The purpose of the third test was to determine whether the effectiveness of the additive system could be re-established and the

TABLE 1-3

CAT CANYON FOAM CHEMICAL AND NITROGEN INJECTION DATA

DATE 1981	CHEMICAL Conc. %v/v	CHEMICAL Dil. Vol.,/lbs	BW-D Vol., lbs	INJECTION Rate, gpm	NITROGEN Slug Vol. SCF	NITROGEN Rate SCF	INJECTION Continuous Vol. SCF	INJECTION Continuous Rate SCFM
5/1	10	4,900	490	18	6,500	176	14,700	64
5/2	10	4,900	490	47	6,200	154	17,100	94
5/3	10	4,900	490	33	6,200	192	17,500	64
5/4	10	4,900	490	25	-	-	10,600	86
5/5	-	-		-	-	-	-	-
5/6	10	4,900	490	46	13,200	152	20,700	78
5/7	10	4,900	490	28	11,300	134	23,000	103
5/8	10	4,900	490	31	10,800	135	23,000	81
5/9	10	4,900	490	28	11,600	145	23,600	87
5/10	10	4,900	490	43	10,400	139	26,200	65
5/11	10	4,900	490	28	6,300	141	24,80	91
5/12	10	4,900	490	43	6,600	154	26,400	97
5/13	10	4,900	490	47	6,700	129	22,200	77
5/14	36	2,500	900	29	-	-	21,500	69
5/15	36	1,684	606	27	-	-	20,500	71
5/16	17	2,359	401	27	-	-	20,500	46
5/17	17	3,671	624	17	-	-	12,100	44
5/18	NO INJECTION: RADIOACTIVE TRACER TESTING							
5/19	17	2,518	428	20	-	-	12,600	94
5/20	20	2,495	499	20	-	-	11,700	37
5/21	-	-	-	-	-	-	-	-
5/22	20	4,230	846	0.39	-	-	-	-
5/23a.m.	20	1,605	321	0.43	-	-	21,400	49
p.m.	20	4,275	855	0.50	-	-	-	-
5/24	20	2,585	517	0.30	-	-	17,000	38
5/25	20	1,070	214	0.21	-	-	19,500	41
5/26	20	1,870	374	0.21	-	-	30,600	74
5/27	20	3,430	686	0.51	-	-	15,100	36
5/28	20	3,295	659	0.49	-	-	16,100	41
5/29	20	5,570	1,114	0.64	-	-	18,900	42
5/30	20	4,765	953	0.57	-	-	21,900	48
5/31	20	5,525	1,105	0.65	-	-	22,400	47
6/1	20	3,520	704	0.42	-	-	28,200	59
6/2	20	1,070	214	0.44	-	-	21,600	49
6/3	20	3,830	766	31 (slug)	-	-	15,600	52
6/4 a.m.	20	5,125	1,025	30 (slug)	-	-	9,900	50
p.m.	20	3,830	766	0.46	-	-	-	-
6/5	20	5,880	1,176	0.66	-	-	14,300	29
6/6	20	2,450	490	0.29	-	-	16,200	41
6/7	20	6,195	1,239	0.75		-	22,000	46
6/8	20	4,055	811	0.50	-	-	18,600	38
6/9	20	4,590	918	0.55	-	-	18,200	37
6/10	20	3,965	793	0.48	-	-	8,100	39
6/11	20	1,605	321	0.18	-	-	9,200	22
6/12	20	1,605	321	0.19	-	-	10,100	26
6/13	20	1,695	339	0.20	-	-	14,300	38
6/14		-	-				14,330	38
TOTALS		161,662	26,865		95,800		776,000	
				TOTAL OF NITROGEN		871,800		

TABLE 1-4

CAT CANYON WELLHEAD DATA

CALIFORNIA LEASE

	38		41		60		71		81		85		86		88		90	
	TEMP °F	WATER %	TEMP °F	WATER %	TEMP °F	WATER %	TEMP °F	WATER %	TEMP °F	WATER %	TEMP °F	WATER %	TEMP °F	WATER %	TEMP °F	WATER %	TEMP °F	WATER %
BACKGROUND 4/23-4/30	229	96	121	95	119	82	107	87	113	85	75	46	86	42	82	58	78	47
1ST WEEK 5/1-5/7	250	90	118	86	109	84	87	62	106	84	75	70	78	46	72	46	76	48
2ND WEEK 5/8-5/14	250	89	120	83	129	83	94	76	105	82	70	62	78	48	72	45	73	40
3RD WEEK 5/15-5/21	248	87	115	80	121	77	97	68	103	76	73	53	77	45	75	46	70	37
4TH WEEK 5/22-5/28	237	88	116	73	119	72	91	63	104	76	77	48	77	43	72	43	69	22
5TH WEEK 5/29-6/4	233	87	115	70	119	73	89	60	105	80	73	47	77	43	72	49	70	11
6TH WEEK 6/5-6/13	238	84	108	78	120	77	83	64	103	81	74	46	78	38	75	45	70	11

Table 1-5

PRE-AND POST-TEST WATER CUTS

(CAT CANYON - PATTERN CAL 80)

WELLS, #	AT START OF TEST (%) (4-30-81)	AT END OF TEST (%) (6-13-81)	CHANGE IN WATER CUT (%)
38	96	84	(12)
41	95	78	(17)
60	82	77	(5)
71	87	64	(23)
81	85	81	(4)
85	46	46	-
86	42	38	(4)
88	58	45	(13)
90	47	11	(36)

increased oil production replicated in the same pattern as the first test. In addition, the test involved:

- A higher concentration and larger volumes of chemicals,
- Achieving a better distribution of steam throughout the test pattern, and
- Testing the technical viability of using the additive system on a routine operating basis.

Injection of chemical and inert gas started in late September 1981, following a steam soak in three of the four production wells and one of the second pattern wells. The injection schedule of chemical and air is shown on Table 1-6. Chemical was injected 3 days per week as a slug with the steam, while compressed air was injected each day. Air injection was discontinued while the chemical was being injected. In total, 21,315 pounds of chemical, 1.7 MMscf of air, and 150,000 barrels of steam were injected.

This second test in the same pattern was a successful verification test as the performance of the pattern improved substantially; oil production reached a peak of 108 barrels per day in December 1981. Chemical injection was then terminated and the steam injection rate reduced by one half. Oil production consequently declined, reaching 40 barrels per day in June 1982. Figure 1-16 summarizes the three-month moving average for oil production, oil cut, and oil-steam ratio for both of the tests in Pattern 590-21.

Incremental oil production was 46,000 barrels; 6,000 barrels from the pattern, 28,000 barrels from the second ring and 12,000 barrels from the third ring. Thus, 0.46 pounds of chemical, 37 scf of air and 3 barrels of steam were injected per barrel of incremental oil produced.

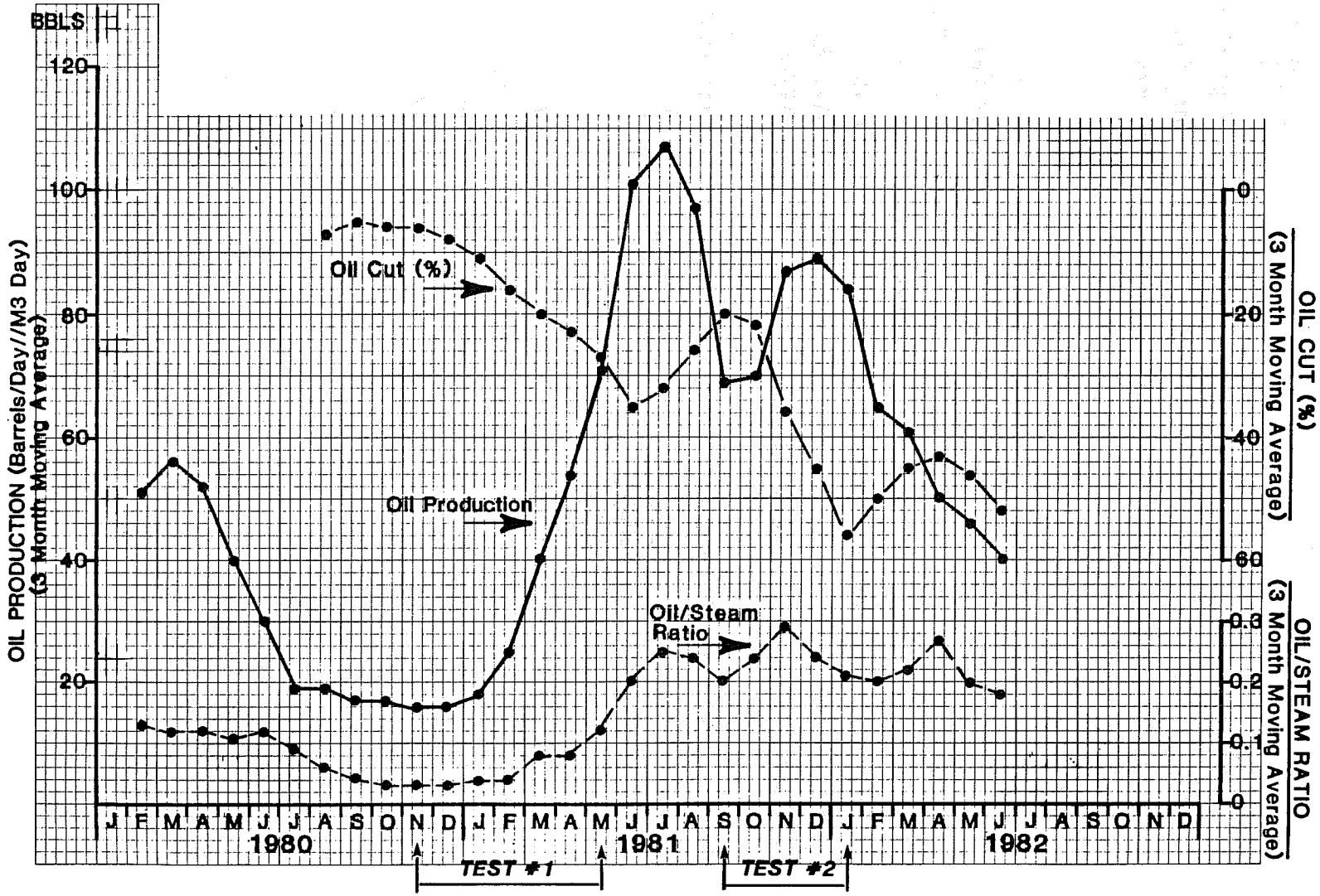
TABLE 1-6

SCHEDULE OF CHEMICAL AND AIR INJECTION
MIDWAY-SUNSET FIELD, CALIFORNIA
FOAM DIVERSION TEST #3

	CHEMICAL INJECTION					AIR INJECTION	
Date 1981	Chemical (Lbs)	Dilute Volume (gallons)	% Volume	% Active Volume	Injection Rate (GPM)	Total (SCF)	Rate (SCFM)
9/17	490	1,100	15	6.3	22	26,900	225
9/18						25,600	215
9/22	490	1,100	15	6.3	39	29,100	230
9/23						22,600	215
9/25	490	1,100	15	6.3	25	26,500	215
9/28						28,600	215
10/1	490	1,100	15	6.3	24	19,300	215
10/5	490	1,100	15	6.3	34	12,000	200
10/6						26,500	220
10/7	490	1,100	15	6.3	31	30,900	225
10/8						26,000	230
10/9	490	1,100	15	6.3	37	26,100	220
10/12	490	1,100	15	6.3	22	26,500	220
11/2	490	1,100	15	6.3	29	26,700	235
11/3						44,300	245
11/4	490	1,100	15	6.3	28	41,300	230
11/5						65,100	225
11/6	490	1,100	15	6.3	32	73,100	265
11/9	490	1,100	15	6.3			
11/13	490	1,100	15	6.3			
11/16	490	660	25	10.5	39	57,400	240
11/17	-	-	-	-			
11/18	490	1,100	15	6.3		46,600	240
11/19	-	-	-	-	-	39,800	220
11/20	490	1,100	15	6.3	37	57,600	240
11/23	490	1,100	15	6.3	35	40,800	230
11/24	-	-	-	-	-	18,300	230
11/25	490	1,100	15	6.3	22	48,200	240
11/30	490	1,100	15	6.3	34	57,900	240
12/1	490	1,100	15	6.3	33	41,900	240
12/2	490	1,100	15	6.3	26	53,700	225
12/3	-	-	-	-	-	44,500	230
12/4	490	1,100	15	6.3	33	71,400	230
12/7	490	1,100	15	6.3	34	52,700	225
12/8	-	-	-	-	-	51,900	245
12/9	490	1,100	15	6.3	39	30,600	225
12/10	-	-	-	-	-	66,100	230
12/11	490	1,100	15	6.3	34	57,200	240
12/14	490	1,100	15	6.3	37	32,500	235
12/15	-	-	-	-	-	53,000	235
12/16	490	1,100	15	6.3	24	71,600	240
12/17	-	-	-	-	-	6,600	75
12/18	490	1,100	15	6.3	24	52,900	235
12/21	490	1,100	15	6.3	31	41,000	235

Figure 1-16

OIL PRODUCTION, OIL CUT, and OIL/STEAM RATIO FROM PATTERN 590-21



The oil-steam ratio, the key economic measure of performance, averaged 0.22 (November 1981 through June 1982). In addition, the oil cut remained highly favorable, averaging 46% during the test. The month-to-month key performance data for the second test are provided on Table 1-7.

Oil production and the oil-steam ratios were also favorable in the surrounding second and third ring wells. At the end of the test in mid-1982, incremental oil was being recovered at about 5,000 barrels per month, as shown previously in Figures 1-9 and 1-10. In the first half of 1982, the oil-steam ratio was 1.16 and 0.59, respectively, for the second and third ring wells affected by the test, as shown on Table 1-8.

Temperature surveys of Well 23 (the key updip well) showed that the steam zone continued to increase and extended over the entire interval at the end of the test, Figure 1-17.

The four pattern production wells showed a much more balanced flow of fluid and production of oil during the second test. Figure 1-18 compares the oil volumetric flow for Pattern 590-12 before the injection of chemicals, during the first test, and during the second test. Both tests succeeded in increasing oil recovery from 18 barrels per day; average production was 72 barrels per day in the first test and 61 barrels barrels per day in the second test. However, in the first test, 65% of the production occurred from Well 194 to the north, while in the second test, production was much more evenly distributed among the four producing wells.

TABLE 1-7
PATTERN PRODUCTION AND WATERCUT, BY WELL
Pattern 590-21, Replication Test

	1981 Nov.	Dec.	1982 Jan.	Feb.	March	April	May	June	Total (Nov-June)
A. Gross Production, Bbls									
Well									
23	1,389	1,146	912	680	917	596	705	476	6,821
24	2,750	1,560	1,356	515	1,448	1,562	258	580	10,029
194	2,258	2,329	1,746	1,342	1,477	1,623	772	985	12,532
209	652	492	--	884	439	278	144	218	3,107
Total	7,049	5,527	4,014	3,421	4,281	4,059	1,879	2,259	32,406
B. Net Oil Production, Bbls									
Well									
23	726	773	578	355	569	498	451	206	4,156
24	587	857	557	209	48	56	76	180	2,570
194	565	1,295	855	823	801	811	446	536	6,132
209	361	352	--	566	261	174	96	134	1,944
Total	2,239	3,277	1,990	1,953	1,679	1,539	1,069	1,056	14,802
C. Watercut, %									
Well									
23	48	33	37	48	38	16	36	57	
24	79	45	59	59	97	96	71	62	
194	75	44	49	39	46	50	42	46	
209	45	28	--	36	41	37	33	38	
Average	68	41	50	43	61	62	43	51	54
D. Steam Injection, Bbls									
	8,800	10,500	11,800	12,500	4,200	6,500	5,200	6,700	66,200
E. Oil-Steam Ratio									
	0.25	0.31	0.17	0.16	0.40	0.24	0.21	0.16	
Average									0.22

TABLE 1-8

PERFORMANCE OF PATTERN 590-21

AND SURROUNDING WELLS

	Pattern 590-21	2nd Ring Wells	3rd Ring Wells
No. of Affected Wells	4	8	6
Oil-Steam Ratio, v/v			
• 1980* Base Year	0.04	0.27	0.74
• 1981	0.14	0.71	0.81
• 1982**	0.20	1.16	0.59
Oil Cut, %			
• 1980* Base Year	6	15	52
• 1981	27	30	39
• 1982**	47	33	30
Oil Production Rate, B/D			
• 1980* Base Year	18	49	49
• 1981	72	147	110
• 1982**	51	147	82

* July-December, 1980
**January-June, 1982

Figure 1-17

TEMPERATURE PROFILE IN PATTERN WELL

(PATTERN 590-21)

WELL NO: 23-21N
CASING 624
LINER: 607-1100
PERFS: 613-1100
PUMP SHOE DEPTH 1049 KB
BBLS. INJECTED: 5721
GENERATOR NO.: 41
ZERO POINT: K.B. = 10
CYCLE NO.: 6

LEGEND
10-19-79
9-30-80
3-19-81
8-10-81
Test # 1
1-7-82
Test # 3

DEGREES FAHRENHEIT

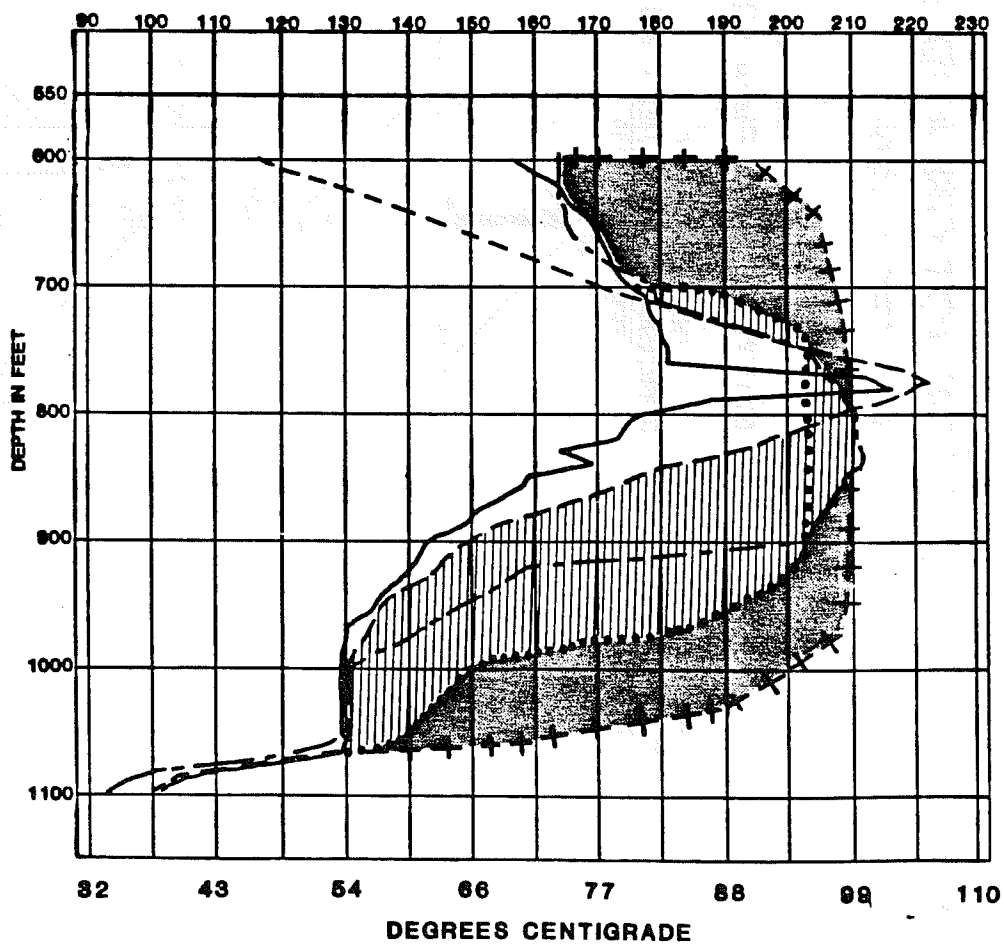
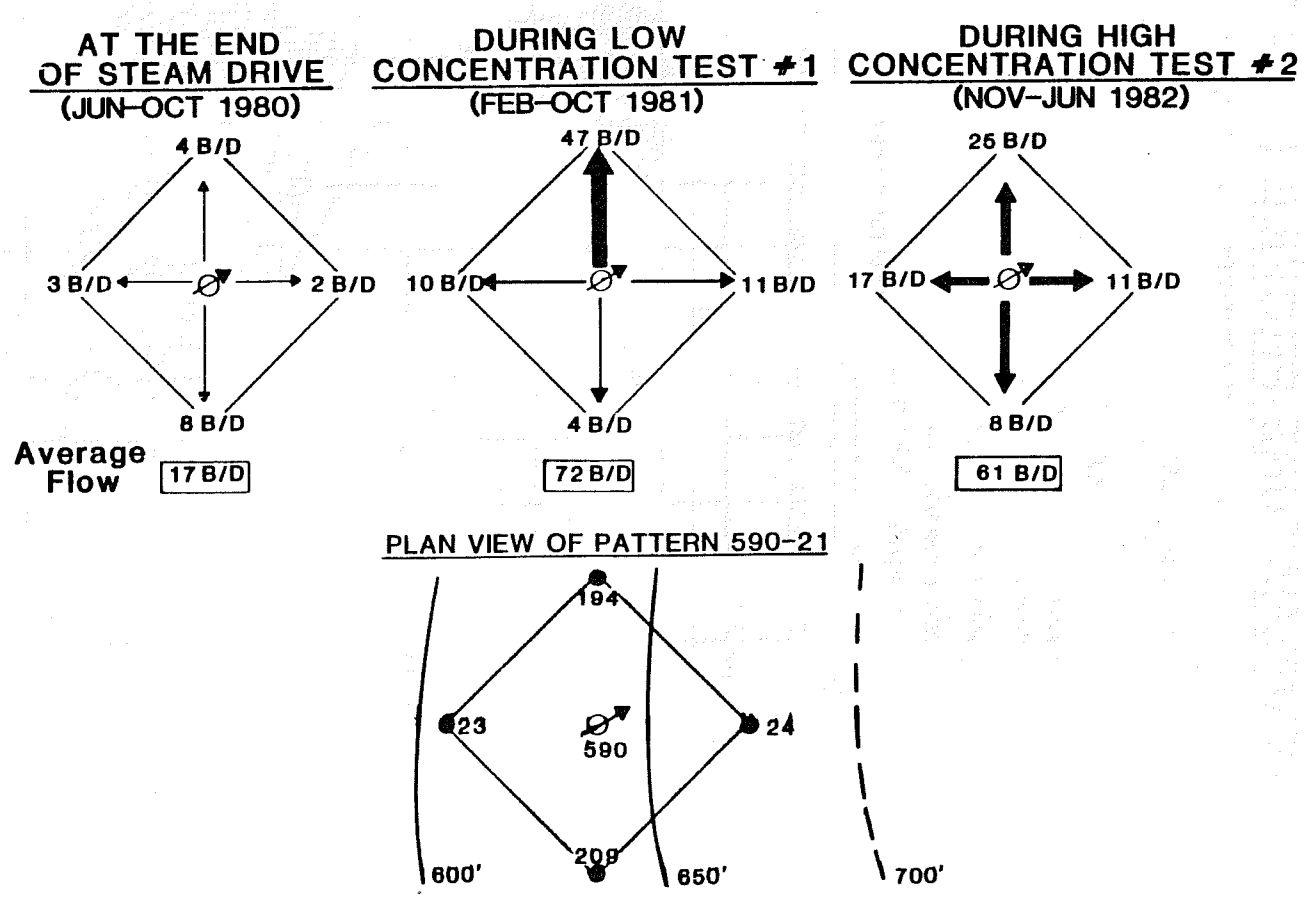


Figure 1-18

ANALYSIS OF OIL PRODUCTION AND DIRECTION OF FLOW

(PATTERN 590-21)

Total Oil Volumetric Flow (B/D)



E. TESTS #4 AND #5. SAN ARDO FIELD

1. Summary

Tests 4 and 5 were conducted in the Aurignac formation of the San Ardo Field, Monterey County, California, on a Texaco, Inc., lease.

Test 4 was a slug test to determine the effect on the pattern wells which form a 4-acre pattern surrounding the injector (actual spacing is 2.5 acres). Test 5 was a continuous, higher concentration test to monitor the effect on both the pattern and second ring wells which form a 20-acre pattern (actual spacing is 2.5 acres) of surrounding wells. Both tests used the same well, Well 85A, as injector for chemicals and nitrogen. The tests are discussed together because both pattern and second ring wells were affected during the tests.

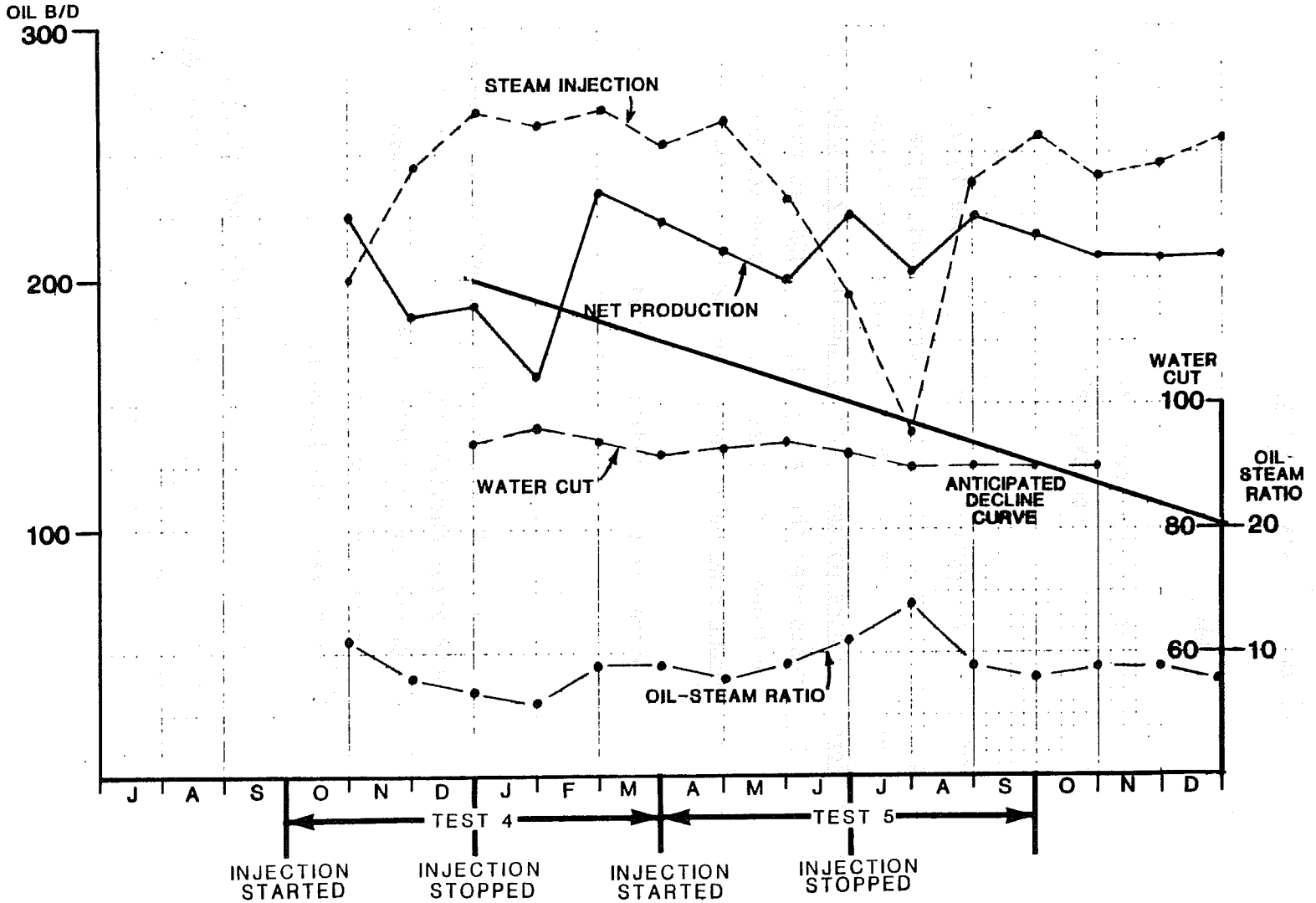
The changes in oil production, water cut, and oil-steam during the tests are shown on Figure 1-19. The results by test are summarized below:

- In Test 4, the second ring responded in February, 1982, a month after chemical injection stopped, with increased oil production (to 235 BPD), a decrease in water cut (to 94%) and an improved oil-steam ratio (to 0.09). Incremental oil recovery was 3,500 barrels.

- For Test 5, injection of chemicals and nitrogen started again in April, 1982. The second ring pattern responded in June with improvements in oil recovery (to 225 BPD), water cut (to 92%) and oil-steam ratio (to 0.11). Incremental oil recovery was 21,500 barrels.

Figure 1-19

STEAM INJECTION INTO AND PERFORMANCE OF ROSENBERG 85 PATTERN



The test results indicate that during Test 4, steam appears to have been diverted to the west and south, leading to increased oil production and an improvement in the water cut of the second ring wells. No improvement in water cut was measured in the pattern wells, probably because they were only completed in the bottom third of the formation.

During Test 5, the second ring west and south wells continued to respond favorably, and the corresponding pattern wells showed a decrease in water cut.

A significant difference in operating procedure between Test 4 and Test 5 was the amount of chemicals and steam injected, as summarized on Table 1-9; about double the amount of chemical was injected over the same period of three months. The results of the two tests are shown below:

	Test 4	Test 5
Chemical/Oil, Lbs/B	19.8	5.4
Air/oil, Scf/B	1,310	32
Steam/oil, B/B	130	30

The larger amount of additives injected in Test 5 appears to be a main reason for the significantly improved result.

2. San Ardo

The San Ardo field is among the largest of the heavy oil deposits in California. It is located in southern Salinas Valley, approximately five miles south of the town of San Ardo in Monterey County, Figure 1-20.

Originally, the field contained 1,450 million barrels of oil in-place and 118 bcf of associated natural gas. Cumulative recovery, principally by steam injection, has been about 350 million barrels.

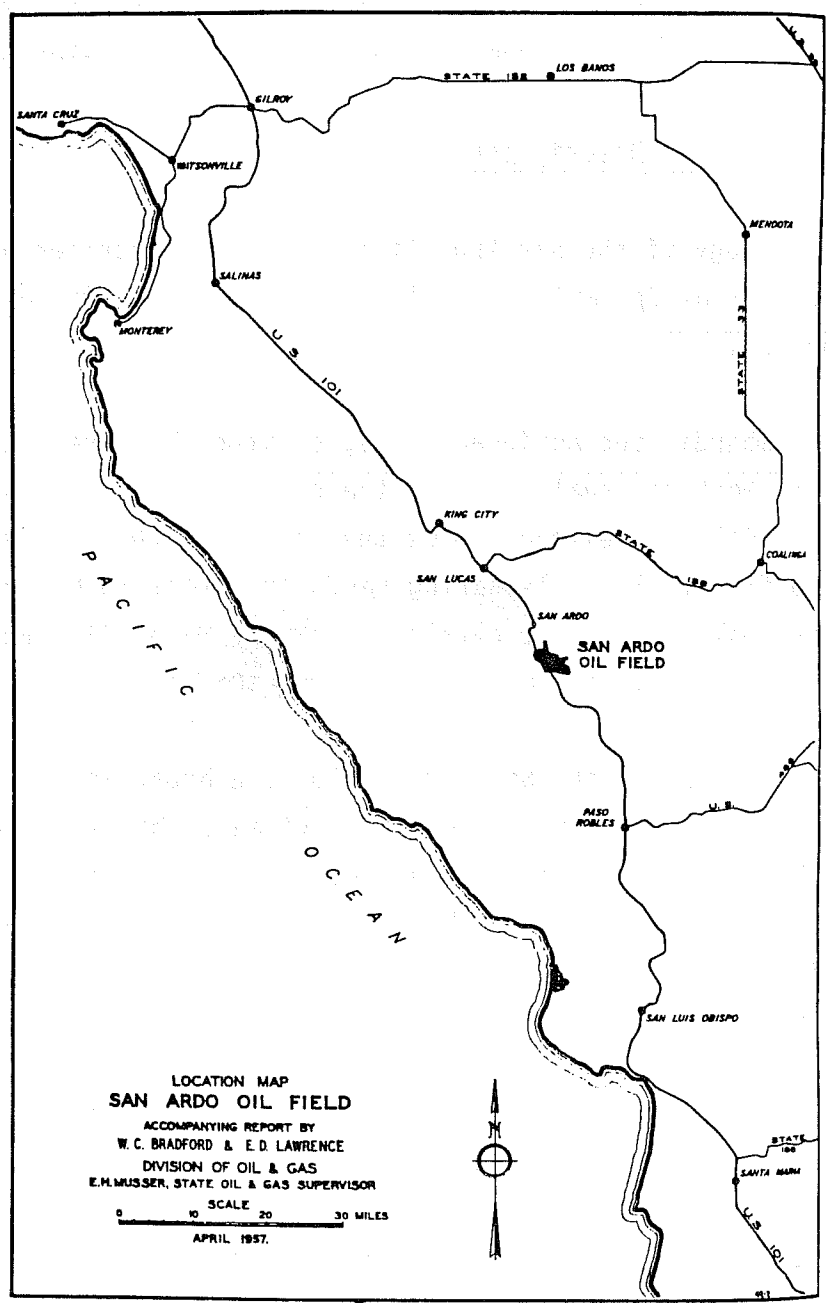
TABLE 1-9

RESULTS OF TESTS 4 and 5 - PRODUCTION, INJECTED MATERIALS AND RATIOS

	TEST 4	TEST 5
A. Oil Production		
Oil Production, MB	3.5	21.5
B. Injection Materials		
Chemical, Mlbs	69.3	116.9
Nitrogen, MMcf	4.6	6.7
Steam, MB	450	620
C. Ratios		
Chemical/Oil, Lbs/B	19.8	5.4
Nitrogen/Oil, Scf/B	1,310	32
Steam/Oil, B/B	130	30

Figure 1-20

LOCATION MAP: SAN ARDO OIL FIELD



Another 200 million barrels are proven and indicated reserves. Thus, the oil remaining in-place after current recovery projects is 900 million barrels.

The eastern portion of the field, which is estimated to contain about 10 percent of the reserves, is not completely developed.

3. Geological Description

The geology of the San Ardo field has been described by Bayer and Zulbert (Summary of Operations, California Division of Oil and Gas, Vol. 42, No. 2).

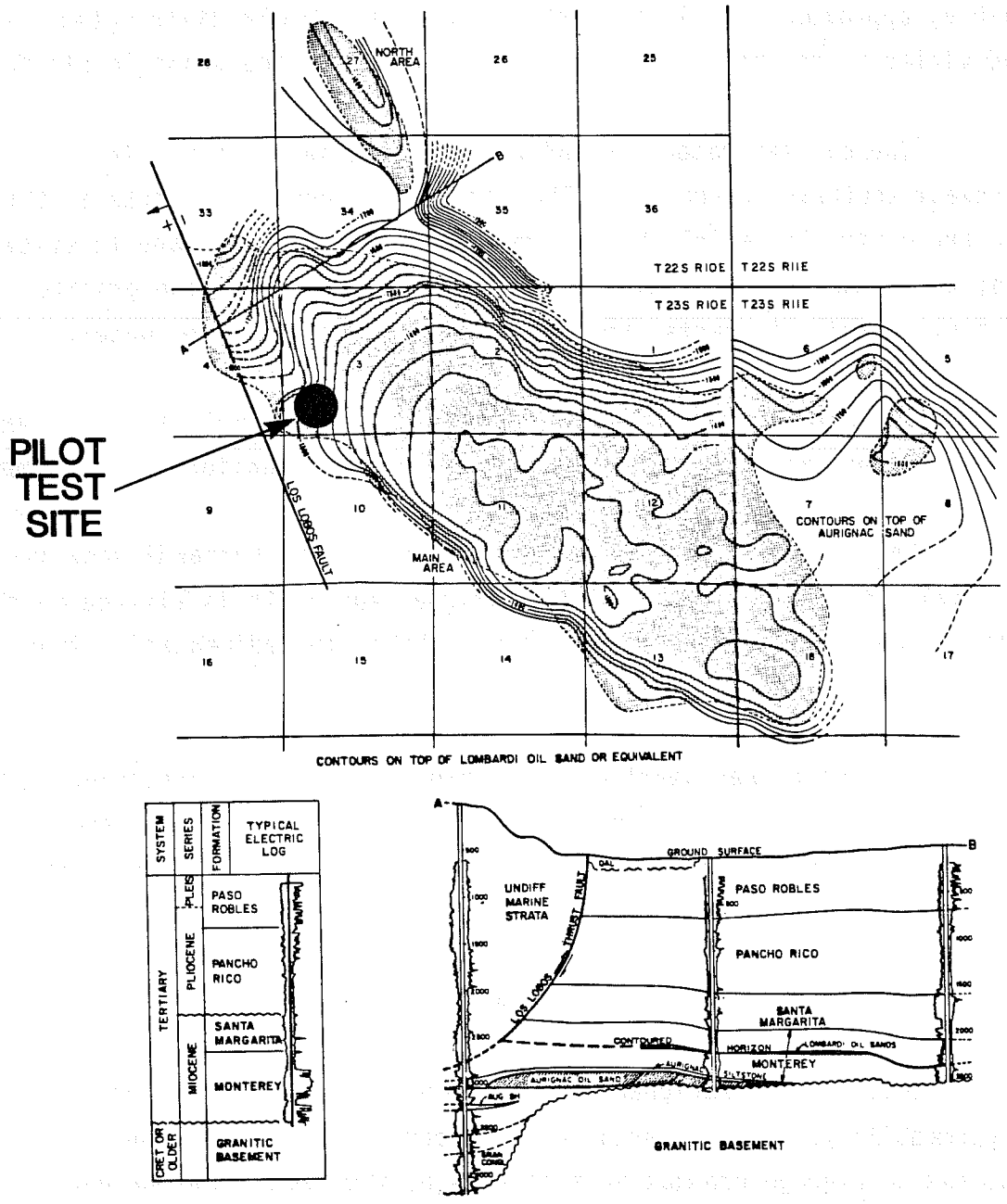
The Lombardi, and Aurignac sands, of upper Miocene age, grade westward into Monterey shale and are the sands in which the oil has been trapped. The shale is believed to be the source of the oil produced in the San Ardo field. The oil-bearing sands are overlain by the Monterey diatomaceous shales which are overlain by Santa Margarita sands. Figure 1-21 is a structure map and cross-section of the San Ardo oil field.

The structure of the San Ardo field is a broad anticline with three minor folds. There is no definite evidence that faulting within the proved limits of the field has affected the accumulation of oil or gas. The existence of the Los Lobos thrust fault along the western edge of the Aurignac area does not affect the accumulation of oil or gas in the producing sands.

San Ardo is one of the few oil fields in the State of California that is known to have a tilted water table that definitely affects the present position of the oil pools. The tilted position of the water table is the result of the tectonic movement which took place during

Figure 1-21

STRUCTURE MAP & CROSS-SECTION: SAN ARDO OIL FIELD



early Pleistocene time. The oil and water evidently failed to readjust to a normal position because the specific gravities are nearly the same.

The Aurignac sand, in the Aurignac area, is coarse grained, friable, approximately 120 feet thick and is uniformly distributed. The sand varies in thickness where it lies directly on the granitic platform.

The oil-saturated area of the Aurignac sand extends in a northwest-southeast direction. The northerly productive limits of this sand are controlled mainly by a permeability change from sand to silty sand; the northwesterly limit by the inclined surface of the granite basement on which it rests; and the southerly limit by edge water.

The Lombardi sand is fine to medium grained, well sorted, unconsolidated, approximately 250 feet thick and is uniformly distributed.

The extent of the oil-saturated area of the Lombardi sand is essentially the same as that of the Aurignac sand. It is limited on the northeast and southwest by a gradational change in sedimentation from pervious sand to impervious shale.

Edge water has started encroaching into the Aurignac sand on the northern flank of the field and also into the Lombardi sand on the northeastern flank of the field. Some wells producing from the Lombardi sand on the northeastern flank have water cuts as high as 90 percent.

4. Reservoir and Crude Characteristics

Lombardi and Aurignac sandstones have unusually high porosity and permeability. The Lombardi, which occurs between 1,900 and 2,100 feet, has an average productive thickness of 120 feet. The Aurignac occurs between 2,200 and 2,400 feet, and averages 50 feet in productive thickness. The two sands are separated by an impermeable siltstone and are produced as separate reservoirs.

The reservoir properties in the project area are as follows:

- Oil Gravity -- 13° API
- Depth -- 2,250 feet
- Oil Viscosity -- 4,500 cp @ $100^{o}F$
- Porosity -- 33%
- Permeability -- 2,200 md
- Net Pay -- 120 feet

The crude oil at San Ardo is of very low API gravity, ranging from 10 to 13° API, with high viscosity and a very low dissolved gas content. There is a very favorable decrease in viscosity and increase in mobility of the crude oil at elevated temperatures. The field thus lends itself to thermal enhanced recovery operations.

5. Test Site

The pilot area is part of Texaco's larger steam drive operations in the San Ardo Field that began in 1965 and now cover 800 acres and produce nearly 20,000 barrels per day of heavy oil. The test pattern is at an advanced stage of depletion and has water cuts in excess of 90%.

The pilot site is shown on Figure 1-22 with an insert showing the test pattern. The project is on Texaco's Rosenberg lease and involves one central injector, Well 85A, five closely spaced producers making a 4-acre pattern and eight surrounding production wells making a 20-acre pattern (actual spacing for both patterns is 2.5 acres). A map of the pattern and the surrounding wells is shown on Figure 1-23. Around the test pattern on all sides are eight steam injection wells that serve to contain the pattern. These wells are indicated by circles.

Typical logs of the formation within the Rosenberg 85 pattern are shown on Figure 1-24. The top of the Lombardi zone is at 1,927 feet and the formation is 140 feet thick. The top of the Aurignac into which

Figure 1-22

LOCATION OF PILOT AREA: SAN ARDO OIL FIELD

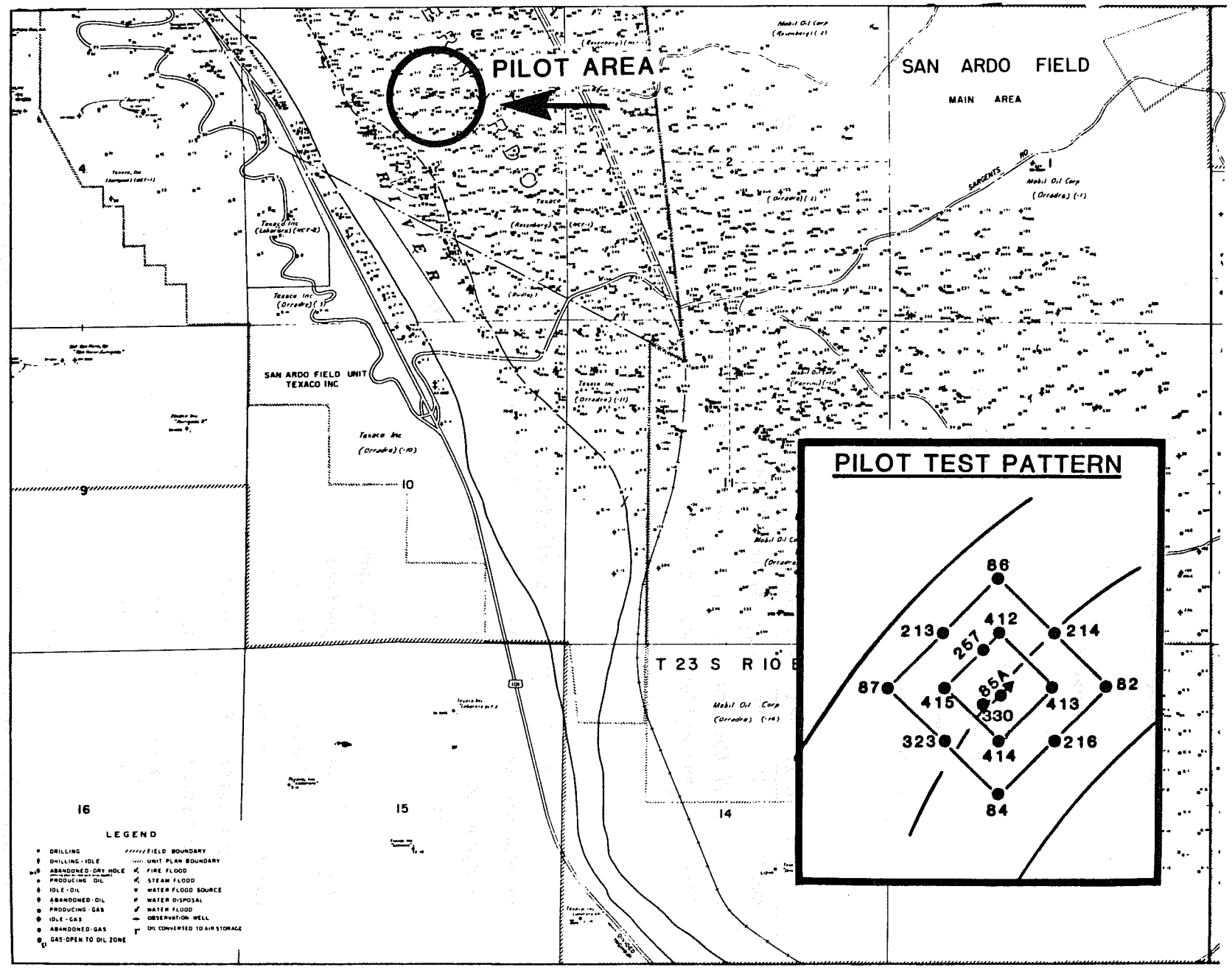


Figure 1-23

SAN ARDO PATTERN AND SURROUNDING WELLS

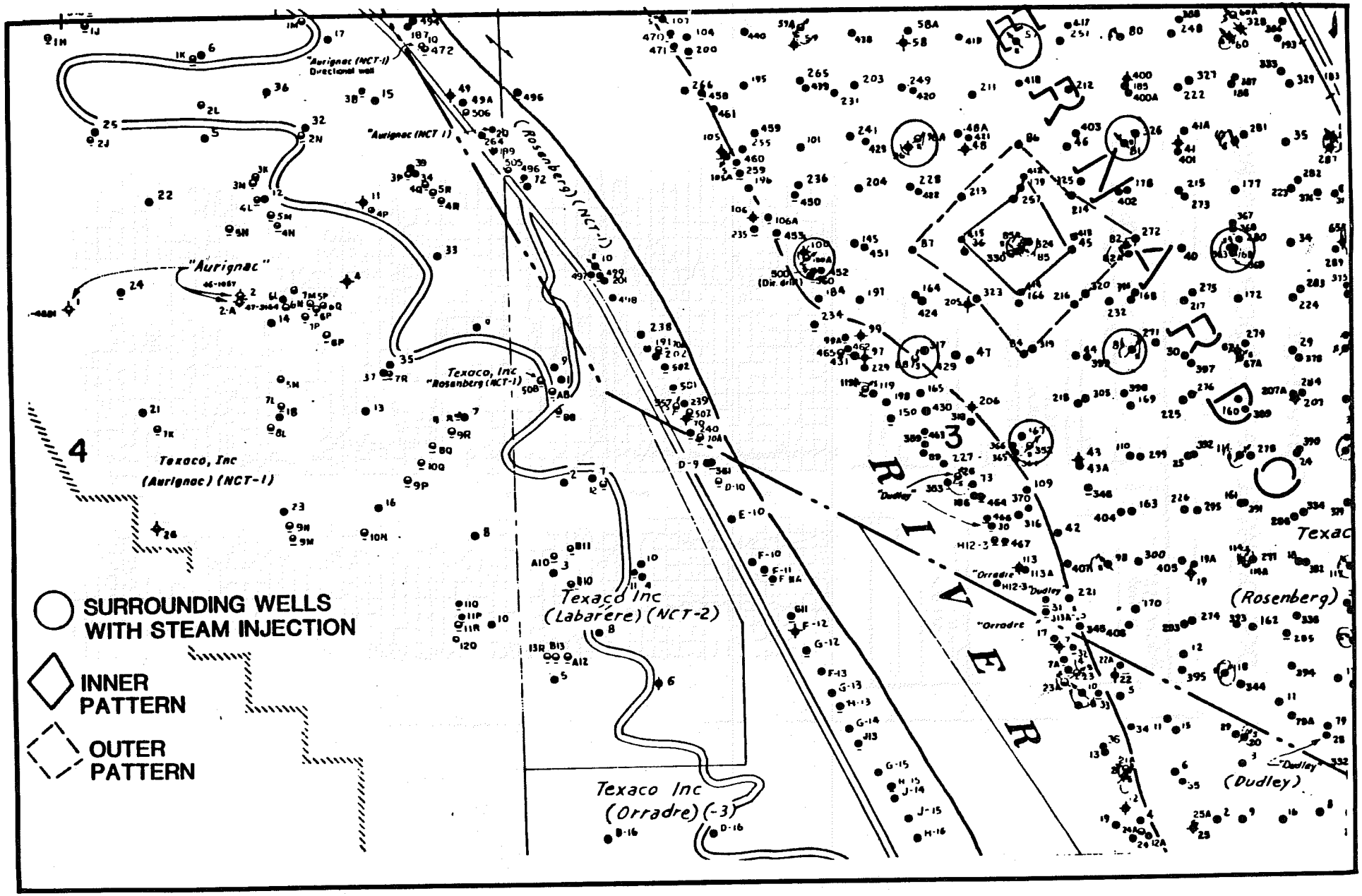
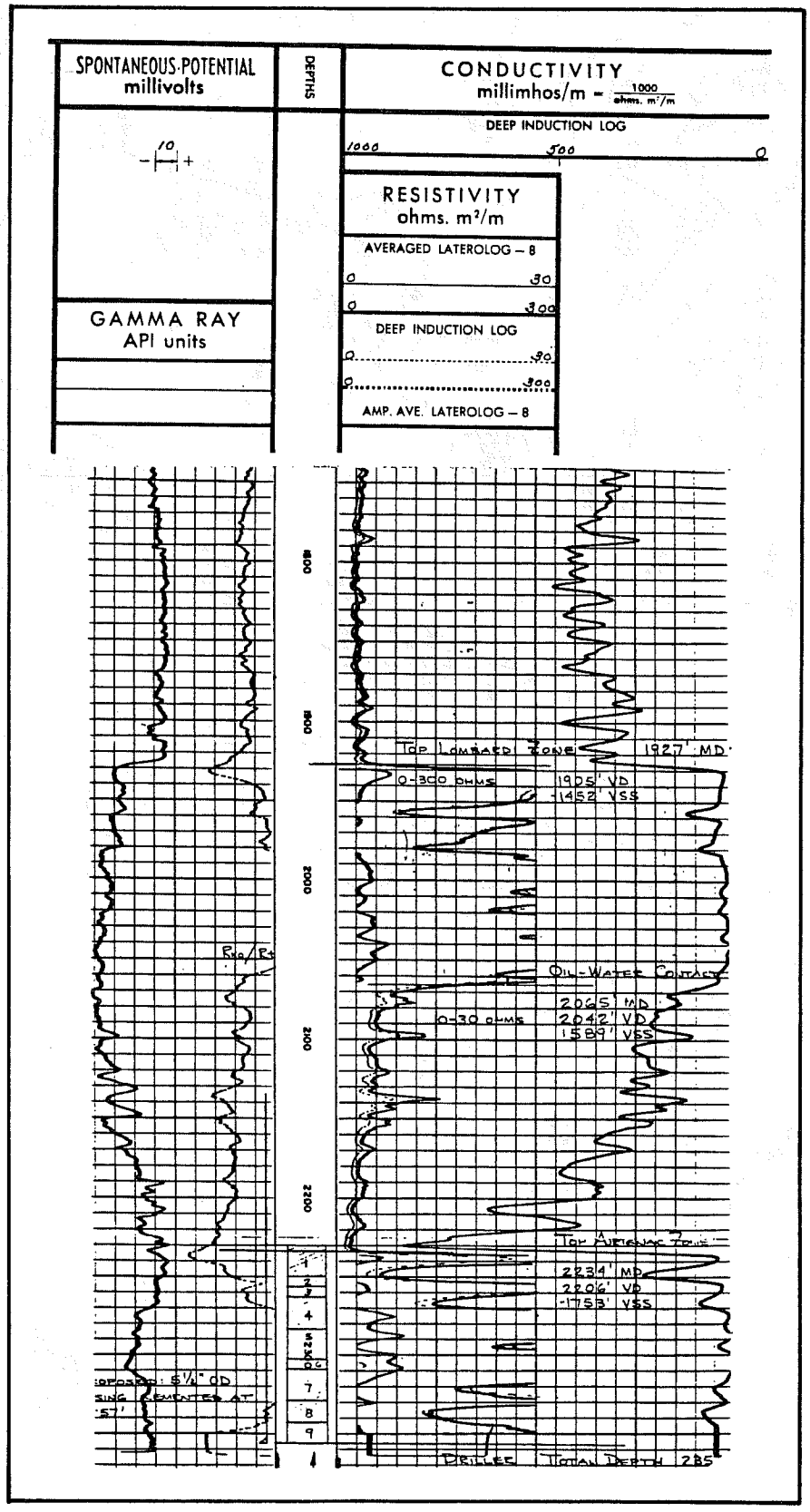


Figure 1-24

LOGS OF WELL 330 -- ROSENBERG 85A



the steam is injected is at 2,230 feet. The formation extends down to the bottom of the well at 2,350 feet.

6. Past Pattern Performance

The historical production from the Rosenberg 85 pattern is shown on Figure 1-25.

The best-fit decline curve drawn through the production data from mid-1977 to mid-1981 shows a production rate decline of 30%, increasing to 35% per year in early 1978. The decline rate remained at 35% per year through late 1981, when the influence of steam additives arrested the decline.

Historically, the oil-steam ratio in Pattern Rosenberg 85 has been above 0.20, reaching a maximum of 0.50 in 1980, Figure 1-25. Starting mid-1980, the oil-steam ratio fell steadily to less than 0.10 by mid-1981.

Prior to the test, the largest steam producing wells were Wells 86, 257, 412, 413, and 415. The first well is the northern second ring well, while the other wells are all pattern wells. The only pattern well not a major steam producer was the south well, Well 414.

7. Pretesting

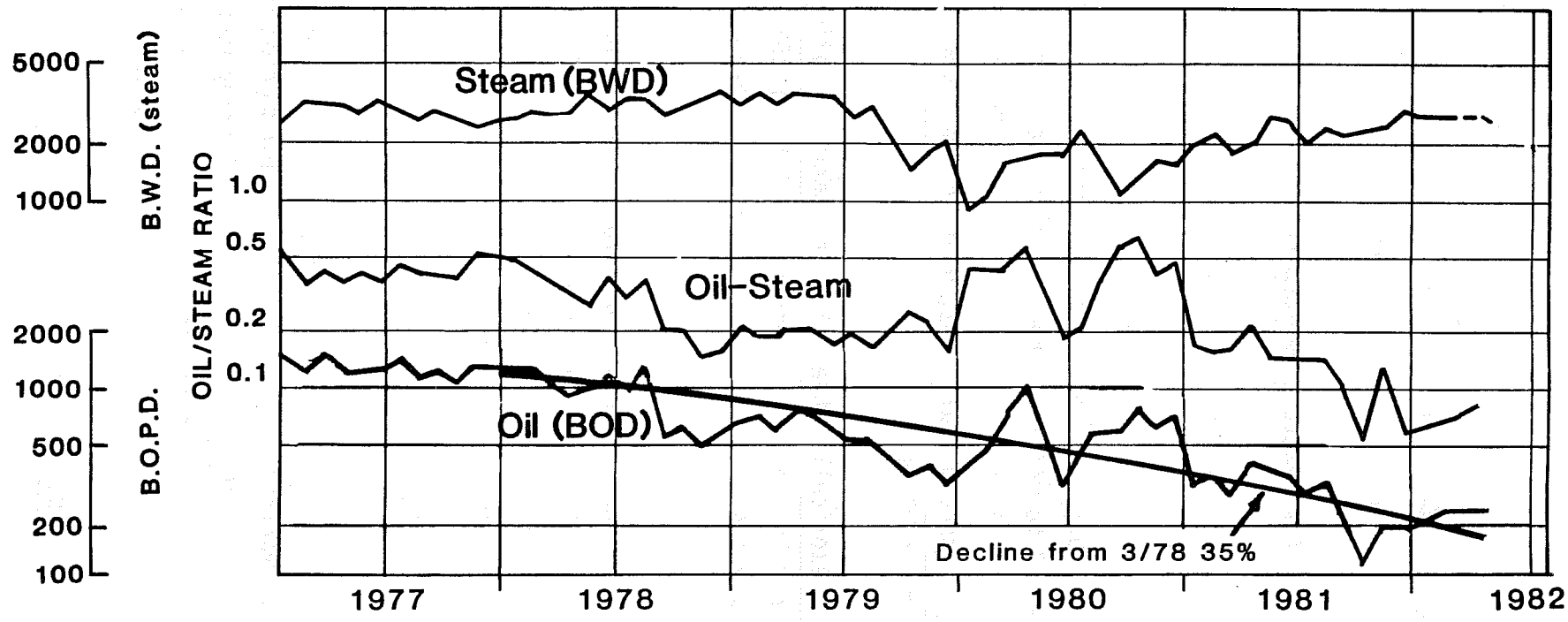
Testing prior to the start of Test 4 in October, 1981, consisted of logging, monitoring of injection and production wells and of three tracer surveys. The purpose of this monitoring was to construct a base line from which to identify changes, both with respect to well performance and to steam channels in the reservoir.

a. Neutron Logs

Four of the five pattern wells, the 400 series, are completed only in the bottom third of the formation, whereas the second ring wells

Figure 1-25

PRODUCTION HISTORY OF ROSENBERG 85 PATTERN



are completed through the entire formation. A comparison of a neutron log run in Rosenberg 330, an observation well, in July 1981 just prior to the test, with corresponding logs run in 1972 and 1976, Figures 1-26, 1-27 and 1-28, does not indicate any significant change in the intervals where vapor is present.

b. Well Monitoring

Pretest well monitoring consisted of measuring water cuts and casing and production line temperatures at each pattern well on a daily basis.

Also monitored daily was the steam quality and flow rate at the test pattern injection well, and steam injection rates at each of the surrounding injection wells. Weekly averages of this data are summarized on Tables 1-10 and 1-11. For the pattern injection well, 85A, the steam quality was about 60% and the injection rate was about 2,300 barrels per day.

About 2,000 barrels of steam per day were injected into each of the steam injection wells surrounding the greater Rosenberg 85A pattern to confine the pattern.

c. Tracers

Two radioactive and one chemical tracer survey were conducted prior to injecting chemical.

The segregation between steam and water at San Ardo was demonstrated by the tracer surveys. The tracer work points to the conclusion that steam vapor is reaching the 20-acre wells at the higher elevations of their completion intervals and the 4-acre wells, whose completions are generally at a lower elevation, are primarily responding to a hot water drive.

Figure 1-26

NEUTRON LOG OF WELL 330 -- ROSENBERG 85A

MARCH 17, 1972

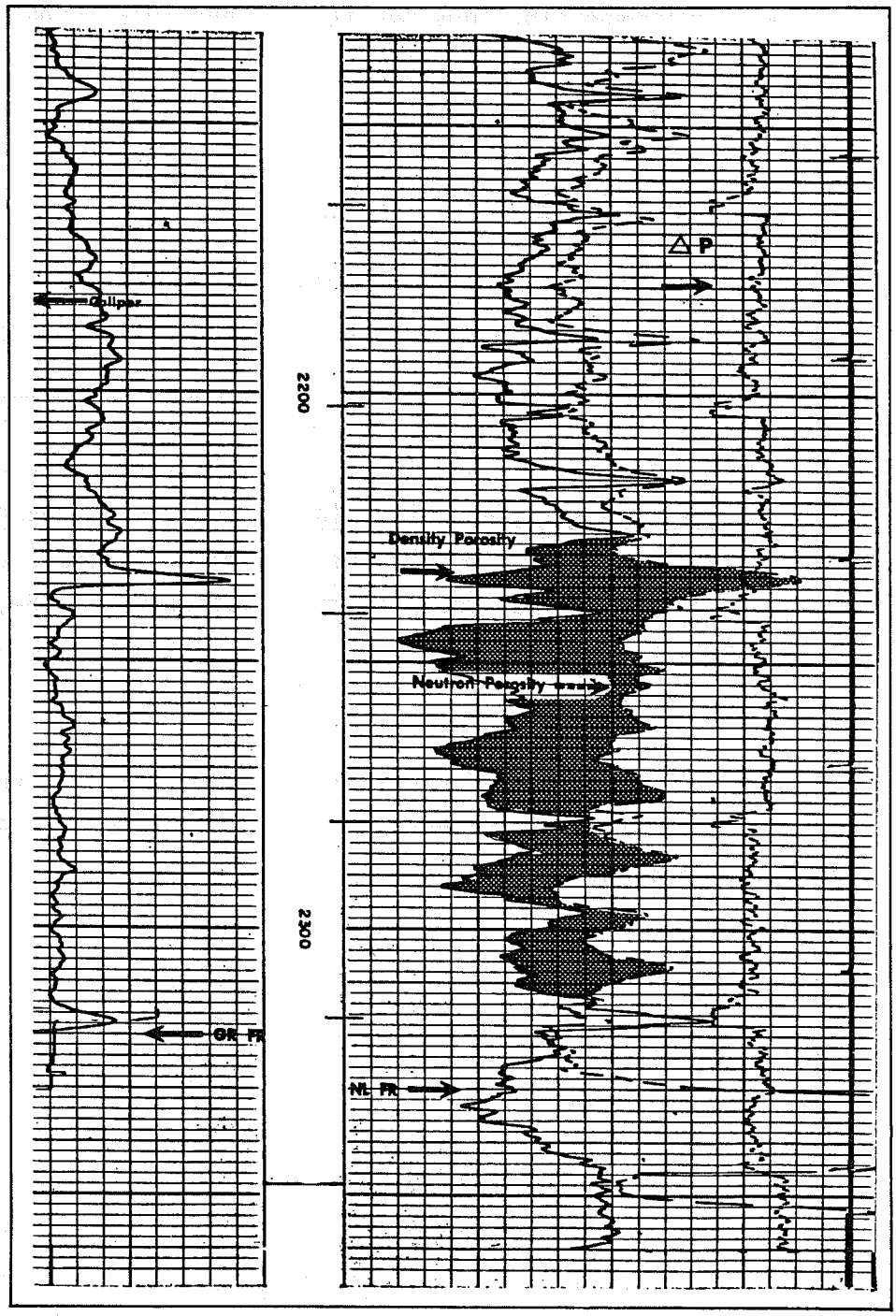


Figure 1-27

NEUTRON LOG OF WELL 330 -- ROSENBERG 85A

OCTOBER 1, 1976

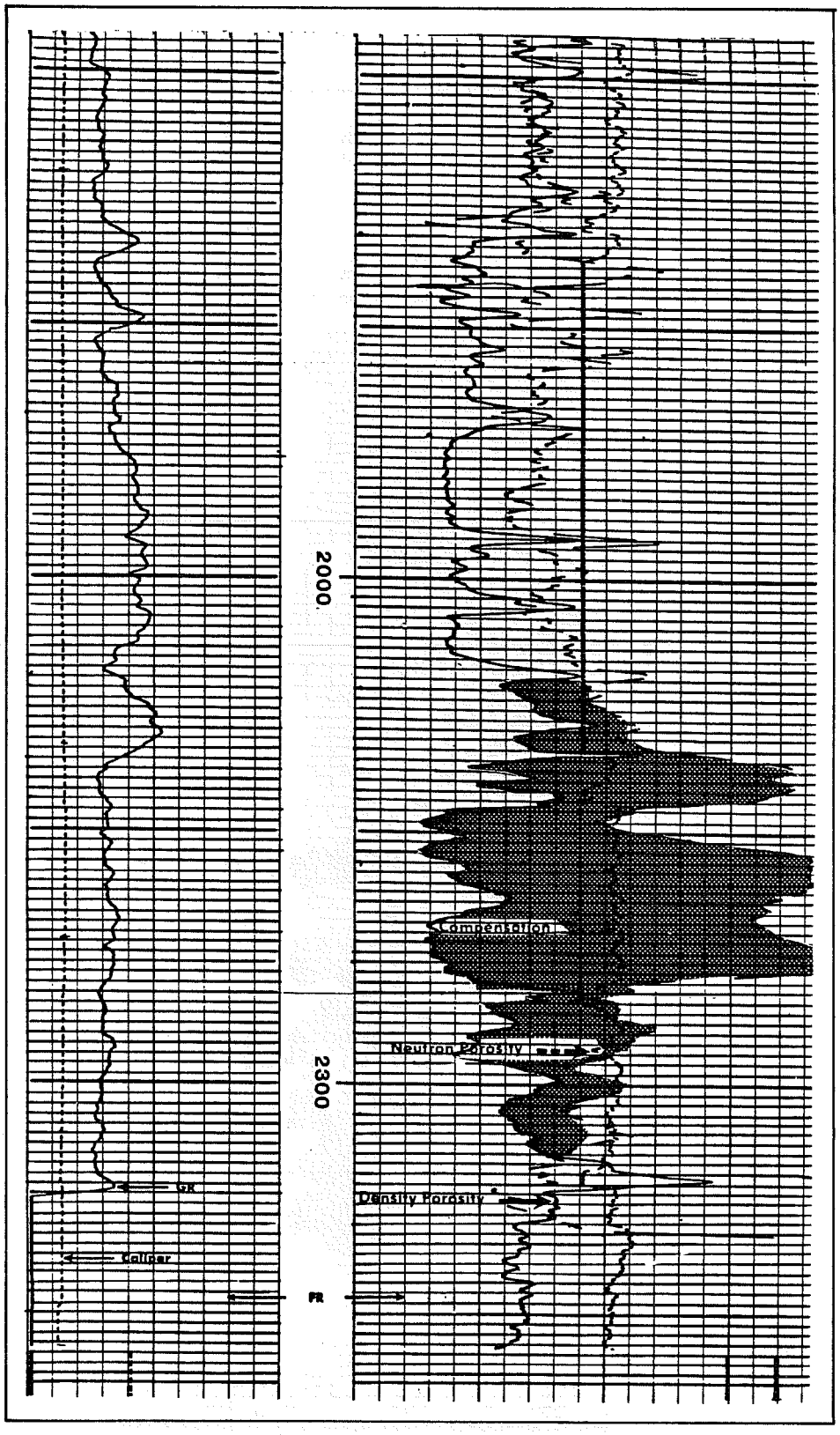


Figure 1-28

NEUTRON LOG OF WELL 330 - ROSENBERG 85A

JULY, 1981

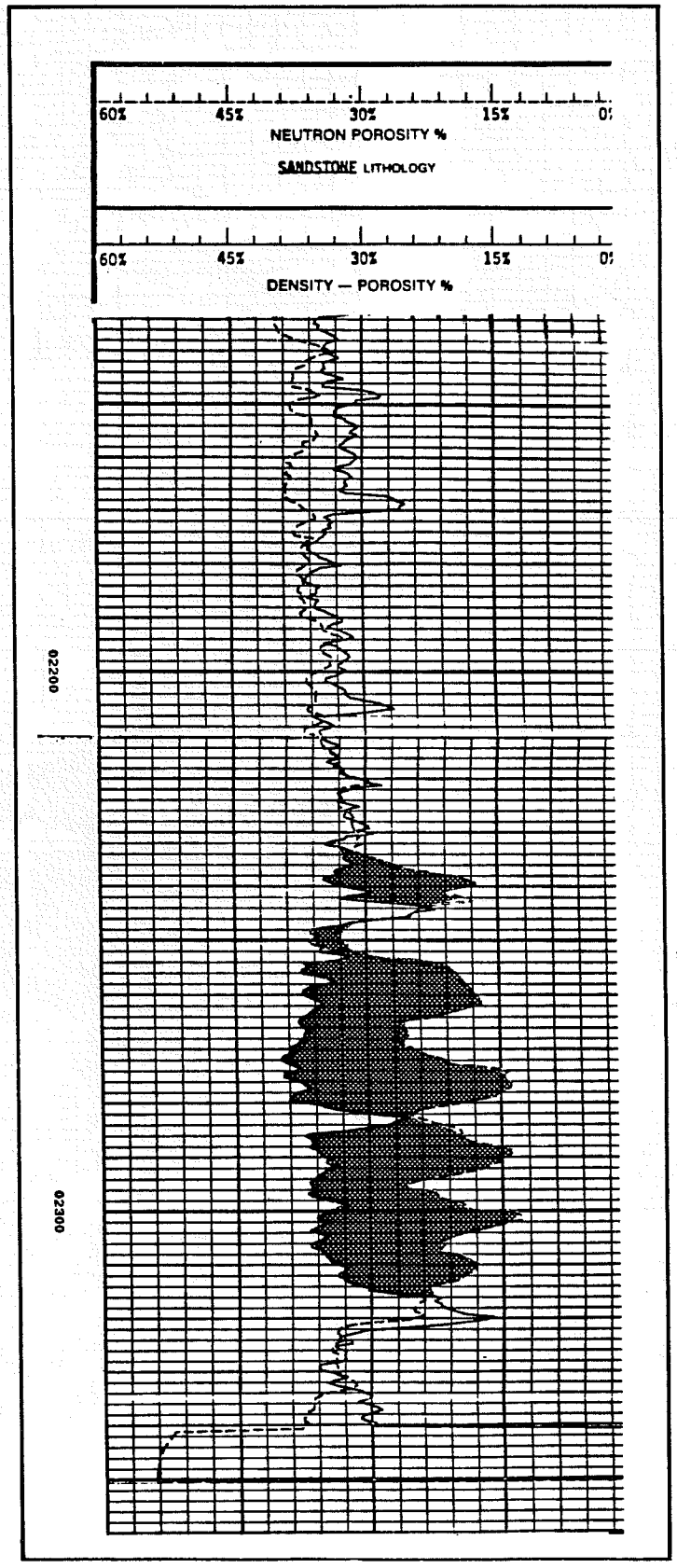


TABLE 1-10

AVERAGE WEEKLY WELLHEAD STEAM PARAMETERS MONITORED AT ROSENBERG 85A INJECTION WELL

TEXACO INC.; SAN ARDO FIELD UNIT

Parameter Monitored:	Average Values for Week Beginning: 9/14/81	9/22/81	9/28/81
Steam Quality, %	65	60	62
Steam Press, psig	400	390	458
Steam Temp, ^{o}F	N.A.	425	450
Steam Rate, B/D	N.A.	2,080	2,380

TABLE 1-11

STEAM INJECTION WELLS SURROUNDING ROSENBERG 85A

TEXACO, INC.; SAN ARDO FIELD UNIT

Averages for the Week Beginning:	Injection Well Number 57	81	83	88	96A	100A
September 14, 1981						
Rate: BSPD	1,750	2,280	1,300	1,050	2,350	2,050
Press., psig	415	450	455	295	405	380
September 21, 1981						
Rate: BSPD	2,130	2,650	1,610	1,860	1,850	1,760
Press., psig	438	483	485	370	470	438
September 28, 1981						
Rate: BSPD	2,225	2,750	1,680	1,930	1,850	1,820
Press., psig	460	493	493	360	472	450

The apparatus for the vapor phase tracer monitoring consisted of a 5 gallon stainless steel condenser and a 55 gallon drum which collected the condensed fluid and noncondensible gas. The drum contained about 20 gallons of a caustic solution to prevent venting of poisonous hydrogen sulfide gas into the atmosphere. Liquid overflow emptied into a second 55 gallon drum for storage until proper disposal, and the noncondensible gases exited past a gamma ray detector connected to a battery powered rate-meter. Radiation levels were determined by subtracting the background radiation readings from the casing gas rate-meter reading.

i. First Tracer Test - Radioactive

Ten curies of Xenon-133 were injected with steam into Well 85A at 2:30 pm on August 31, 1981. Although Rosenberg 257 was shut in, the vapor phase radioactive tracer was injected as scheduled because there was a considerable casing flow. This well is important since it is a large steam producer and the only well of the inner pattern completed in the upper portion of the zone.

Monitoring started after one hour and was stopped after 70 hours. During this period, responses were measured at eight wells. The time when the tracer first was measured and the level and duration of response are summarized below by well in chronological order:

Tracer Test 1 - Rosenberg 85A

Time (hours)	Well, Direction	Counts/Min. Above Background	Duration of Response, hrs
4.0	84S	100	46.5
4.2	213NW	100	65.8
5.5	323SW	100	64.5
5.5	414S	150	64.5
13.0	216SE	150	33.5
21.5	257NW	350	3.0
21.5	87W	250	21.0
42.5	82E	100	--

The strongest response was in the second ring wells; pattern wells showed only minor or no response. The results of the first vapor phase radioactive tracer program are presented in Table 1-12.

The results of this test were unexpected. Well 86, and the main pattern wells, Wells 257, 412, 413, and 415 were by far the largest steam producers, but little or no tracer was found at these wells. In the case of Well 257 this may be because the tubing production was shut in.

ii. Second Tracer Test - Nitrogen

On September 17, 1981 at 11:40 a.m., 48,000 scf of nitrogen was injected with the steam entering Well 85A. The nitrogen rate was maintained at a constant low level for 26.3 hours. The wells were sampled twice daily for two days. To determine how long nitrogen would remain in the reservoir, additional samples were collected on the fifth and seventh days.

The major responses were obtained to the north at Wells 213, 214, 257, and 412, as follows:

- Well 257 responded first by producing N_2 two hours after N_2 injection started and at an increasing rate through the next day.

- Well 213 responded after 47 hours and continued to produce N_2 at a very high rate throughout the test. This well had the strongest response.

- Well 214 responded by producing N_2 at a relatively high rate on the 19th of September, the day after injection of N_2 was discontinued.

TABLE 1-12

VAPOR PHASE RADIOACTIVE TRACER MONITORING

Elapsed Time (hours)	Well #	Counts/Min Above Background
4.0	84*	100
4.2	213*	100
5.5	84	100
5.3	213	100
5.5	323*	100
5.5	414*	150
6.5	213	100
6.8	414	1300
7.8	84	150
7.5	213	100
7.8	414	600
8.5	84	300
9.0	414	400
10.3	84	400
10.5	213	100
10.5	323	150
10.5	414	150
11.8	84	400
11.8	213	200
11.8	323	300
11.8	414	200
13.0	84	400
13.0	213	1200
13.0	216*	150
13.0	323	250
13.0	414	600
14.5	84	900
14.5	213	400
14.5	216	1300
14.5	323	100
14.5	414	1400
16.0	84	1600
16.0	213	600
16.0	216	750
16.0	323	250
16.0	414	300
17.8	84	1600
17.8	213	400
17.8	216	1500
17.8	323	150
17.8	414	100
18.5	84	150
18.5	216	200
18.5	323	150
18.5	414	400
20.0	84	200
20.0	213	100
20.0	323	150
20.0	414	200
21.5	84	200
21.5	87	TR
21.5	213	200
21.5	216	100
21.5	257*	350
21.5	323	150
21.5	414	130
24.5	84**	100
24.5	257	100
24.5	323	100
24.5	414	100
26.0	84	100
26.0	323	200
26.0	414	100
30.0	213	300
30.0	323	300
35.5	213	400
35.5	323	300
38.0	213	200
38.0	323	800
40.8	213	400
40.8	323	400
42.5	82*	100
42.5	84	100
42.5	87*	250
42.5	213	250
42.5	216	100
42.5	323	650
42.5	414	600
46.5	84	400
46.5	213	100
46.5	216	100
46.5	323	100
46.5	414	500
50.5	84	100
50.5	323	100
50.5	414	100
54.3	323	150
54.3	414	200
57.5	323	600
61.5	213	100
61.5	323	900
61.5	414	100
66.0	213	100
66.0	323	200
70.0	213	200
70.0	323	200
70.0	414	100

* First appearance of vapor phase tracer

** Cool Water pumped down casing to kill steam

Ten Curies of Xenon-133 injected into Rosenberg Steam Injection Well #85A on Aug. 31, 1981 at 2:30 PM.

Texaco, Inc., San Ardo Field Unit.

- Well 412 responded 19 hours after injection started with the response building up very strongly while N_2 was injected and then tapering off with some N_2 being produced a week after injection stopped.

The results are presented in Table 1-13.

Although the wells showing the biggest response differ between the two tracer tests, the results are fairly consistent, as little tracer was found at the wells with the largest steam production. The one exception is Well 257 which was shut in during the radioactive tracer test and was pumping during the nitrogen tracer test.

Due to the unexpected appearance of tracer at certain wells and the absence at the wells where tracer was expected, it was decided to repeat the tracer test.

iii. Third Tracer Test - Radioactive

A third vapor phase radioactive tracer test was conducted at San Ardo beginning on September 29, 1981. The results, which are shown in Table 1-14, are arranged in chronological order.

The most striking aspect of the tracer test is the extremely high steam mobility, which in most cases was on the order of two hundred feet per hour. Tracer appeared at the pattern wells first and was measured within 3 hours at all five wells. Although tracer was found at all the major steam producers early, some second ring wells responded just as fast. The largest responses were measured after 1.6 hours in Well 257 (NW inner pattern) followed by Well 323 (SW outer pattern) after four hours. The third largest response was after 2.8 hours in Well 216 (SE outer pattern).

* * * * *

TABLE 1-13

NITROGEN VAPOR PHASE TRACER - SECOND TRACER TEST

Well #	Date	Oxygen mol %	Nitrogen mol %	Time of Sample	Elapsed Time (hours)
82	9/18	ND	ND	12:40pm	25.0
	9/19	ND	ND	2:00pm	50.3
	9/22	ND	1.26	11:30am	119.8
84	9/17	ND	ND	2:30am	2.8
	9/18	ND	ND	7:35am	19.9
	9/19	ND	ND	10:10am	46.5
	9/22	ND	ND	1:20pm	121.7
	9/24	ND	ND	11:00am	167.3
86	9/18	ND	ND	12:50pm	25.1
	9/19	ND	ND	2:30pm	50.8
	9/22	ND	ND	10:30am	120.8
	9/24	ND	0.06	10:00am	166.3
87	9/18	ND	ND	8:25am	20.8
	9/18	ND	ND	1:30pm	25.8
	9/19	0.06	0.24	1:55pm	50.3
	9/22	ND	ND	11:00am	119.3
213	9/17	ND	ND	2:45pm	3.1
	9/18	ND	ND	8:15am	20.6
	9/19	ND	19.53	10:45am	47.1
	9/19	0.10	23.61	1:50pm	50.2
	9/22	ND	3.66	11:00am	119.3
214	9/18	ND	ND	12:45am	25.1
	9/22	ND	9.59	10:00am	118.3
	9/24	ND	5.56	10:00am	166.3
216	9/18	ND	ND	6:40am	19.0
	9/18	ND	ND	12:30pm	24.8
	9/18	ND	ND	1:50pm	26.1
	9/19	ND	4.94	2:05pm	50.4
	9/22	ND	ND	10:00am	118.3
	9/24	ND	ND	12:45pm	167.3
257	9/18	ND	2.02	1:15am	1.6
	9/19	ND	8.56	2:20pm	50.7
	9/22	ND	0.32	10:30am	118.8
	9/24	ND	ND	10:15am	167.1
323	9/18	ND	ND	7:45am	20.1
	9/18	ND	ND	1:50am	26.2
	9/19	ND	ND	10:20am	46.7
	9/19	ND	ND	1:30am	49.8
	9/22	ND	ND	11:00am	119.3
412	9/17	ND	ND	1:50pm	2.2
	9/18	ND	0.85	7:05am	19.4
	9/18	ND	2.95	1:00pm	25.3
	9/19	ND	12.99	11:00am	47.3
	9/19	ND	12.93	2:15pm	50.6
	9/22	ND	6.67	10:30am	118.8
	9/24	ND	3.83	10:15am	166.6
413	9/17	ND	ND	1:35pm	1.9
	9/18	ND	ND	6:55am	19.2
	9/18	ND	ND	9:45am	46.1
	9/19	ND	ND	2:10am	50.5
	9/22	ND	ND	10:00am	118.3
414	9/18	ND	ND	7:20am	19.7
	9/18	ND	ND	1:50pm	26.3
	9/19	ND	ND	10:00am	46.3
	9/19	ND	ND	1:15pm	49.6
	9/22	ND	ND	9:50am	118.2
	9/24	ND	0.09	10:15am	166.6
415	9/17	ND	ND	2:15pm	2.6
	9/18	ND	ND	8:00am	20.3
	9/19	ND	0.89	1:40pm	49.9
	9/22	ND	4.15	11:30am	119.8
	9/24	ND	ND	10:30am	166.8
	9/18	ND	ND	12:25pm	24.9
	9/19	ND	1.93	10:30pm	46.8

Nitrogen injected continuously from 9/17/81 @ 11:40am to 9/18/81 @ 2:00pm.

Volume Injected: 48,000 SCF.

ND = Not determined in sample, although measured for.

TABLE 1-14

SAN ARDO VAPOR PHASE RADIOACTIVE TRACER - THIRD TEST

Well No.	Elapsed Time Before Detection of R.A. Tracer (hr)	Distance From Injection Well 85A (ft)	Steam Mobility (ft/hr)	Rate x Duration Weight Factor*	Casing Production* during R.A. Monitoring (bbl/hr
413	1.1+	370	335	0.47	80
412	1.3+	299	230	0.4	91
257	1.6	300	190	56.2	82
414	1.9	354	185	15.5	8
213	2.0	457	230	22.3	3
86	2.6+	598	230	3.6	No Data
82	2.7	674	250	35.3	No Data
216	2.8	504	180	37.1	No Data
415	3.2	331	105	4.7	95
84	4.7	701	150	49.2	5
323	4.1	551	135	38.8++	3
87	13.2	661	50	8.6	16
214	16.5+	438	27	0.4	25

* Weight Factor = average cpm x 60 x duration of positive readings.

** Casing production for 9/29/81.

\+ Extremely low positive readings may be artifacts.

++ Large weight factor is due to extremely long duration, which may be an artifact.

The main conclusions that can be drawn from the three tracer studies are that:

- All the pattern and second ring surrounding wells were affected by steam injection into Well 85A.

- The mobility of the steam is very high.

- Except for Well 257, the wells with the largest steam production did not have the biggest response. This indicates that the produced steam is either from outside the greater pattern (Well 86) or due to flashing of hot water at the production well (Wells 412, 413 and 415).

- Little steam vapor is reaching the pattern wells where completions (except for Well 257) are restricted to the bottom of the zone.

- Steam vapor is reaching the outer wells which are completed over the entire interval.

Table 1-15 summarizes the results of the three tracer tests by well--the time to first response and the level of response.

8. Injection of Chemical, Nitrogen and Steam

Injection of chemical and nitrogen for Test 4 started in early October 1981 and continued to December 24, 1981. After three months of monitoring, Test 5 started in April, 1982. Injection of chemical and nitrogen was stopped on June 14, 1982 while steam injection and monitoring continued through September. Table 1-16 summarizes the injection by month of chemical, nitrogen and steam through June, 1982.

TABLE 1-15
SUMMARY OF RESPONSE TO TRACER TESTS

	Tracer Test		
	1-Radioactive	2-Nitrogen	3-Radioactive
Pattern Wells			
257*	21.5/350 1/	1.6/2.02 1/	1.6/56.2 1/
412*		19.4/0.85	1.3/0.4
413*			1.1/0.47
414	5.5/150		1.9/15.5
415*		49.9/0.89	3.2/4.7
First Line Wells			
86*			2.6/3.6
214		118.3/9.59	16.5/0.4
82	42.5/100		2.7/35.3
216	13.0/150		2.8/37.1
84	4.0/100		4.7/49.2
323	5.5/100		4.1/38.8
87	21.5/250	13.2/8.6	
213	4.2/100	47.1/19.53	2.0/22.3

1/ Elapsed Time to first response (hours)/Level of Reponse
Test 1: Counts above Background for initial response
Test 2: N_2 Mol % in initial response
Test 3: Rate x Duration weighing factor

* Largest steam producing wells

TABLE 1-16

SCHEDULE OF INJECTION MATERIALS - SAN ARDO

	1981				1982					
	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	March	April	May	June
A. Chemical										
gallons (diluted)	---	6,198	6,107	5,697	---	---	---	6,606	12,906	6,732
gallons (conc. chem.)	---	1,998	3,025	2,750	---	---	---	3,303	6,453	3,366
pounds	---	17,800	27,000	24,500	---	---	---	29,400	57,500	30,000
B. Nitrogen										
Mscf	---	1,192	1,613	1,804	---	---	---	1,539	2,879	1,258
Rate, scf/m	---	---	---	---	---	---	---	400	417	400
C. Steam										
Rate, BPD	2,230	1,988	2,449	2,673	2,628	2,688	2,546	2,684	2,329	1,940
Quality, %	61	56	62	61	63	58	63	69*	69*	68*
Temp, °F	438	442	453	460	455	467	457	478	445	
Pressure, psi	424	410	462	622	477	450	444	452	442	

*Higher number possibly due to sampling techniques.

a. Injection Schedule - Test 4

Test 4 was a slug test, the purpose of which was to determine the effect on the wells of the inner pattern. The injection procedure of chemical and nitrogen was as follows:

Monday Wednesday Friday	1.	Co-inject with steam 275 gallons of concentrated (42% active) chemical diluted with approximately 600 gallons of soft water at a rate of 18-20 gallons per minute.
	2.	Allow steam to spread chemical into the formation for one hour.
	3.	Inject 80,000 scf of nitrogen at a rate of 350 scf per minute.
Tuesday Thursday	1.	Inject 120,000 scf of nitrogen at a rate of 350 scf per minute.

Test 4 injection started in October and had originally been scheduled for termination on December 4, 1981. However, several of the wells began to show a decrease in the water cuts in November. After meeting with Texaco staff, it was decided to continue the injection for another three weeks. Chemical and nitrogen injection therefore continued until December 24, 1981.

Pattern oil production initially continued to decline. In February, 1982, an increase in net oil production was recorded. This increase in net production is in spite of a decrease in gross production of about 700 B/D from January, 1982. Thus, the pattern water cut dropped from 96% to 94%. The oil-steam ratio also started to increase.

After the production increase in February, monthly production started to decrease slowly, but remained above the November level through April, the last month of Test 4.

b. Injection Schedule - Test 5

The purpose of this test was to use continuous (rather than a slug) injection of chemicals and nitrogen to divert steam to the outer ring of wells.

The injection procedure in this second phase was:

- A 50% solution of the foam chemical was injected at a low rate (2 gpm) during the night followed by a day-long slug of nitrogen at about 350 scf per minute.
- The daily chemical injection was 2,940 pounds of concentrated chemical (six drums) diluted with six drums of softened water.
- Injection took place five nights per week with a total of 116,900 pounds of concentrated chemical (240 drums) injected over eight weeks.

The average steam injection rate was 2,300 barrels per day of about 60% quality.

Test 5 was originally scheduled to start in March, but because the pattern continued to respond, the start was delayed. Chemical and air injection was resumed on April 14, 1982. As with Test 4, production of oil continued to decline initially, before increasing in June to 225 barrels per day. At the same time, an improvement in the water cut and oil-steam ratio was measured through December, 1982, when monitoring stopped.

Overall, during the two tests, 7.4 pounds of chemical, 451 scf of nitrogen, and 1.4 barrels of steam were injected per barrel of oil produced. The improvement in response was much faster in Test 5 than in Test 4 and is presumably due to the greater volume of chemical and nitrogen injected.

c. Injected Materials

The table below shows the amount of chemicals and nitrogen injected during each of the two tests:

	Injectant	
	Test 4	Test 5
Chemical, pounds	69,300	116,900
Nitrogen, Mcf	4,609	6,676

The injection period for each test lasted three months, but about double the volume of chemical was injected for Test 5.

The rate of steam injection remained relatively constant during the two tests; the averages for Test 4 and Test 5 were 2,400 and 2,300 barrels per day, respectively. The quality was constant at 63% (some higher measurements during Test 5, up to 69%, may be due to sampling procedures).

Steam continued to be injected after the injection of chemicals and nitrogen was discontinued. The steam injection rate by month is summarized below:

	Month	Steam Injection, B/D
Test 4	October, 1981	1,988
	November	2,449
	December	2,673
	January, 1982	2,638
	February	2,688
	March	2,546

	Month	Steam Injection, B/D
Test 5	April	2,684
	May	2,329
	June	1,940
	July (interrupted)	1,407
	August	2,381
	September	2,560
	October	2,391
	November	2,426
	December	2,535

Steam temperature and pressure remained relatively constant throughout the two tests at about 460°F and 450 psi.

d. Fluid Balance

Throughout the injection period of the tests, the pattern produced more fluid than was injected. Starting in August, (two months after chemical injection stopped), the fluid balance reversed and more fluid was produced per month than was injected.

Month	Fluid Balance, BPD		
	Gross Prod.	Steam Inj.	Δ
December, 1981	3,173	2,673	500
January, 1982	4,462	2,638	1,824
February	3,750	2,688	1,062
March	2,841	2,546	295
April	2,869	2,654	215
May	3,183	2,329	854
June	2,693	1,940	753
July	2,023	1,407	616
August	2,237	2,381	(144)
September	2,246	2,560	(314)
October	2,169	2,391	(222)
November	1,735	2,426	(691)

The excess fluid is assumed to be from the surrounding patterns and shows they had an effect on the performance of pattern Rosenberg 85A.

9. Test Response

The responses to the pilot tests were monitored five ways.

a. Oil Production. The production of oil was measured and the increment determined.

b. Analysis of Casing Gas. The noncondensible components of casing gas were analyzed for nitrogen content.

c. Water Cut. The water cut was measured at each well.

d. Total Dissolved Solids. The total dissolved solids in the produced water were determined.

e. Temperature Survey. The temperature gradient was monitored in Well 330, an observation well.

Each of these monitoring efforts are described below.

a. Production

Production from the wells surrounding Well 85A is produced into a central tank battery and not monitored individually. However, the water cuts were measured on a daily basis for each well.

During the tests, the key indicators of technical success, the oil production, water cut, and oil-steam ratio, all showed an improvement, Figure 1-29. Table 1-17 tabulates the monthly gross and net oil production, steam injection, as well as the pattern water cut and the oil-steam ratio.

The first few months after injection of chemical and nitrogen started, the oil-steam ratio continued to decline. Then, it slowly

Figure 1-29

STEAM INJECTION INTO AND PERFORMANCE OF ROSENBERG 85 PATTERN

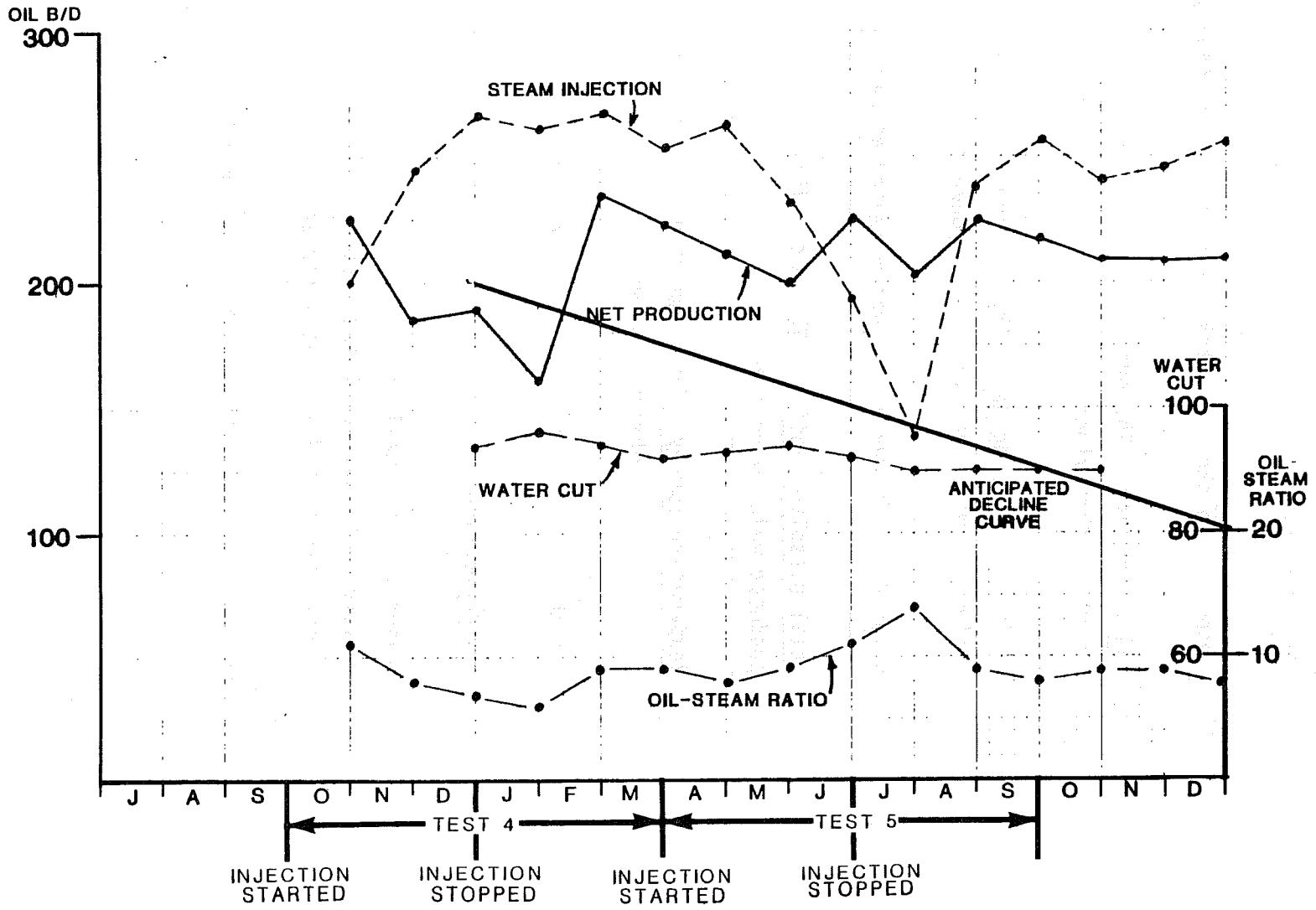


TABLE 1-17

PATTERN PERFORMANCE--ROSENBERG 85A

	Barrels Per Day				
	Gross Production	Net Oil Production	Steam Injection	Water Cut, %	Oil-Steam Ratio, %
A. Test 4					
October	No Data	224	1,988		0.11
November	No Data	185	2,449		0.08
December	3,173	188	2,673	94	0.07
January, 1982	4,462	161	2,638	96	0.06
February	3,750	235	2,688	94	0.09
March	2,841	224	2,546	92	0.09
April	2,869	212	2,654	93	0.08
B. Test 5					
May	3,183	200	2,329	94	0.09
June	2,693	225	1,940	92	0.11
July	2,023	205	1,407	90	0.14
August	2,237	225	2,381	90	0.09
September	2,246	217	2,560	90	0.08
October	2,169	210	2,391	90	0.09
November	1,735	210	2,426	88	0.09
December	No data	210	2,555		0.08

increased, reaching 0.11 by June when injection of additives was discontinued. After a further increase in July, probably due to low steam injection, the oil-steam ratio declined to 0.09. Similar improvements were noticed for the water cut and oil production.

In view of the ambiguous nature of the base line for the Rosenberg 85A pattern, the effect of the chemical additives which were initially injected into Rosenburg 85A is difficult to definitively assess. The table below summarizes the anticipated incremental recovery for 1982, by month in barrels per day, assuming a 35% decline rate in oil production as the base line:

Month	Oil Prod., BPD	Anticipated Production, BPD	Incremental, BPD
Test 4			
October, 1981	224		
November	185		
December	188	200	
Test 5			
January, 1982	161	192	(31)
February	235	183	52
March	224	175	49
April	212	167	45
May	200	158	42
June	225	150	75
July	203	142	61
August	225	133	92
September	217	125	92
October	210	117	95
November	210	108	104
December, 1982	210	100	112

If the 35% annual decline rate established since mid-1977 is the basis for comparison, then the chemical additive system had a positive effect increasing the oil production on the order of 50 to 100 barrels per day. The incrementally produced oil is 25,000 barrels; 3,500 barrels in Test 4 and 21,500 barrels in Test 5. No incremental oil production is counted past December, 1982.

An upper bound of 80,000 barrels of incremental production is reached by assuming that the pattern would have been abandoned as uneconomic in January, 1982 when the oil-steam ratio reached 0.06.

b. Casing Gas Analysis

Analyses of the casing gas were made on a regular basis and indicated that there is a swept communicating interval between the injection and producing wells (except, perhaps, Well 84) through which the nitrogen can flow.

Tables 1-18 and 1-19 show the results for pattern and second ring wells, respectively. The analysis of the casing gas shows that by November 10, 1981, nitrogen had reached every well in the pattern. In the case of Wells 87, 213, 257, 323 and 415, the percent nitrogen was fairly high. These wells are all to the west of the injector.

The results of Test 4 through December, 1981 are summarized below:

- Pattern Wells. At all the pattern wells, N_2 appeared on a sustained basis, indicating there was vapor phase communication between injector and producers. The largest response occurred at Well 415 to the west (the results at Well 412 must be due to faulty sampling since N_2 appeared before it was injected).

TABLE 1-18
CASING GAS ANALYSES
PATTERN ROSENBERG WELLS
(mol %)

Date 1981	Nitrogen	Carbon Dioxide
WELL 257		
8/18	0.04	89.20
8/20	ND	88.76
8/27	ND	91.00
9/1	ND	89.08
9/10	ND	82.11
9/15	ND	76.30
9/18	2.02	61.76
9/19	8.56	79.60
9/22	0.32	83.23
9/24	ND	88.31
10/16	ND	79.91
11/10	17.68	72.17
11/27	6.17	81.67
12/4	17.54	74.91
WELL 412		
8/11	24.37	69.79
8/18	15.67	76.72
8/19	1.36	85.76
8/25	ND	90.92
9/1	ND	79.49
9/10	ND	85.71
9/15	29.95	58.74
9/17	ND	85.97
9/18	0.85	83.96
9/18	2.95	80.26
9/19	12.99	62.42
9/19	12.93	67.52
9/22	6.67	79.23
9/24	3.83	86.86
10/1	4.76	80.19
11/10	7.60	82.72
11/27	31.70	56.27
12/4	1.92	91.12
12/11	0.22	89.33

Date 1981	Nitrogen	Carbon Dioxide
WELL 413		
8/6	0.26	91.99
8/19	ND	92.43
8/27	ND	92.30
9/10	ND	85.16
9/15	ND	62.14
9/17	ND	75.24
9/18	ND	68.47
9/18	ND	62.97
9/19	ND	76.27
9/19	ND	79.37
9/22	ND	85.46
10/11	ND	81.01
10/16	ND	76.27
11/10	0.19	89.67
11/27	2.10	86.20
12/4	3.98	87.84
WELL 414		
8/25	ND	95.34
8/27	ND	95.62
9/1	ND	97.00
9/10	ND	90.80
9/15	ND	56.94
9/18	ND	78.92
9/18	ND	69.64
9/19	ND	85.59
9/19	ND	87.38
9/22	ND	89.68
9/24	0.09	86.95
10/2	ND	91.96
11/10	0.31	92.05
11/27	0.94	91.04
12/4	4.33	85.34

Date 1981	Nitrogen	Carbon Dioxi.
WELL 415		
8/6	ND	89.37
8/11	ND	92.44
8/18	ND	90.64
8/20	ND	88.43
8/25	ND	90.65
8/27	ND	88.75
9/1	ND	90.08
9/10	ND	90.59
9/15	1.01	87.60
9/17	ND	89.91
9/18	ND	82.97
9/19	1.93	60.91
9/19	0.89	81.02
9/22	4.15	87.29
9/24	ND	89.90
10/1	ND	87.11
11/10	29.63	61.84
12/4	61.20	30.18
12/11	3.49	85.08

ND = Not determined in sample, although measured for.

TABLE 1-19
CASING GAS ANALYSES
FIRST RING ROSENBERG WELLS
(mol %)

Date 1981	Nitrogen	Carbon Dioxide
WELL 82A		
8/19	ND	91.08
8/25	ND	85.03
8/27	ND	88.34
9/1	ND	91.59
9/10	ND	83.10
9/15	ND	66.96
9/18	ND	85.38
9/19	ND	77.44
9/22	ND	80.63
10/1	ND	72.64
11/10	0.26	83.43
11/27	0.64	77.78
12/4	0.09	74.21
12/11	0.39	67.54
WELL 84		
8/11	0.08	96.92
8/20	ND	96.96
8/25	ND	97.00
8/27	ND	97.00
9/17	ND	95.51
9/18	ND	95.20
9/18	0.18	74.01
9/19	ND	51.58
9/19	ND	62.15
9/22	ND	70.03
9/24	ND	91.72
10/2	ND	82.96
10/16	ND	90.09
11/10	ND	92.72
11/27	ND	89.37
12/4	ND	93.52
12/11	1.28	91.81

Date 1981	Nitrogen	Carbon Dioxide
WELL 86		
8/18	ND	86.86
8/20	ND	88 22
8/25	ND	89.35
9/10	ND	73.60
9/18	ND	73.42
9/19	ND	75.86
9/22	ND	76.90
9/24	1.46	64.35
10/1	ND	75.04
10/16	0.03	72.85
11/10	2.84	78.09
11/27	38.58	51.09
12/4	14.65	76.00
12/11	24.52	63.97
Well 87		
8/11	ND	96.01
8/20	ND	94.24
8/25	ND	92.92
9/1	ND	47.84
9/15	ND	71.66
9/18	ND	86.82
9/18	ND	85.26
9/19	0.24	63.48
9/22	ND	86.84
10/2	ND	73.77
10/16	ND	76.13
11/10	21.82	68.14
11/27	38.58	51.09
12/4	14.65	76.00
12/11	24.52	63.97

Date 1981	Nitrogen	Carbon Diox
WELL 213		
8/6	ND	94.73
8/11	54.55	28 60
8/18	44.36	37.52
8/25	ND	60.23
8/27	ND	73.85
9/1	ND	54.52
9/10	ND	54.90
9/15	ND	57.31
9/17	ND	63.34
9/18	ND	62.42
9/18	ND	69.44
9/19	19.53	39.05
9/19	23.61	35.96
9/22	3.66	75.98
9/24	ND	54.28
10/2	ND	70.71
11/10	40.11	33.70
11/27	51.61	29.48
12/4	69.59	18.00
12/11	40.05	44.89
WELL 214		
8/11	0.17	82.44
8/20	ND	69.33
8/25	ND	67.43
8/27	ND	78.96
9/1	ND	77.59
9/15	ND	89.69
9/18	ND	64.50
9/22	9.59	76.67
9/24	5.56	73.46
10/16	1.03	73.46
11/10	2.90	77.36
11/27	13.26	50.87
12/4	8.18	72.81

ND = Not determined in sample, although measured for.

TABLE 1-19 cont.

CASING GAS ANALYSES

FIRST RING ROSENBERG WELLS

(mol %)

Date 1981	Nitrogen	Carbon Dioxide
WELL 216		
8/6	12.99	61.38
8/19	ND	67.63
8/25	ND	70.18
8/27	ND	44.46
9/1	ND	72.84
9/10	ND	52.21
9/15	ND	64.42
9/18	ND	73.23
9/18	ND	65.31
9/19	ND	97.00
9/19	4.94	38.30
9/22	ND	58.31
9/24	ND	55.33
10/1	ND	64.72
10/16	ND	52.81
11/27	8.03	71.14
12/4	6.38	76.09
12/11	3.85	90.62

Date 1981	Nitrogen	Carbon Dioxide
WELL 323		
8/11	ND	81.05
8/18	ND	82.30
8/20	ND	83.51
8/25	ND	87.75
9/1	ND	88.93
9/10	ND	85.20
9/18	ND	75.82
9/18	ND	76.97
9/19	ND	76.00
9/19	ND	76.00
9/22	ND	81.77
9/24	ND	53.73
10/16	5.62	70.11
11/27	7.13	74.55
12/4	14.69	75.13
12/11	13.88	64.78

ND = Not determined in sample, although measured for.

- Second Ring Wells. All of the second ring wells showed a response to nitrogen injection, except Well 84, to the south. The largest responses were in Wells 87 and 213 to the west.

The noncondensible casing gas of each well was also monitored throughout Test 5, except for Well 257 which was consistently shut in. In two wells, Wells 84 and 86, nitrogen was not detected. (The 5/19/82 sampling on Well 86 is thought to be contaminated.) These wells are second ring wells to the south and north, respectively. In the remaining ten wells, nitrogen was found in fairly high quantities, typically over 50 mol percent, Table 1-20.

Very few of the analyses show any hexane and heavier components. It is probable that this is an artifact of sampling since the very hot casing gas was cooled and the condensed liquids separated from the non-condensible gases.

c. Water Cut

The average monthly water cut is shown on Table 1-21 for the pattern and second ring wells. The table shows that:

- At the beginning of the tests, the water cut at all wells, except Well 323, was high at 80% to 100%.

- Two wells, Well 257 and 323, each showed one month of major improvement in February and March, respectively, during Test 4.

- The water cut improved significantly for two second ring wells, Wells 84 and 87, starting in March and continuing through Test 5.

TABLE 1-20

NONCONDENSIBLE GAS ANALYSIS, SAN ARDO

(mol %)

Date 1982	Oxygen	Nitrogen	Carbon Dioxide	Methane	Hexane+
WELL #82A					
4/26	ND	1.56	92.73	2.72	ND
5/3	ND	36.55	59.01	0.92	0.53
5/19	ND	55.56	41.44	ND	ND
6/2	ND	64.94	30.72	1.17	0.18
6/7	ND	56.41	35.32	2.98	1.64
6/28	ND	73.71	21.15	2.14	ND
WELL #84					
4/26	ND	ND	97.00	ND	ND
5/3	ND	ND	97.00	ND	ND
5/19	ND	ND	97.00	ND	ND
6/2	ND	ND	97.00	ND	ND
6/7	ND	ND	97.00	ND	ND
6/28	ND	ND	97.00	ND	ND
WELL #86					
4/26	ND	ND	86.58	10.42	ND
5/3	ND	ND	68.75	29.25	ND
5/19	ND	1.77	81.53	13.70	ND
6/7	ND	ND	68.92	28.08	ND
6/28	ND	ND	59.09	37.92	ND
WELL #87					
4/26	ND	59.38	38.87	ND	0.75
5/3	ND	68.38	27.50	ND	1.12
5/19	ND	64.34	32.66	ND	ND
6/7	ND	62.72	32.90	ND	0.27
WELL #213					
4/26	ND	46.93	43.74	6.33	ND
5/11	ND	53.65	40.57	2.79	ND
5/24	ND	53.72	40.68	2.60	ND
WELL #214					
4/26	ND	3.19	88.38	5.43	ND
5/3	ND	4.31	87.50	4.88	0.31
5/11	ND	4.28	87.32	5.40	ND
5/19	ND	9.61	76.16	11.24	ND
5/24	ND	3.38	81.45	12.17	ND
6/7	ND	2.98	86.77	7.05	0.20
6/28	ND	ND	93.38	3.62	ND

ND=Not determined in sample, although measured for.

TABLE 1-20 (Continued)
NONCONDENSIBLE GAS ANALYSIS, SAN ARDO
(mol %)

Date 1982	Oxygen	Nitrogen	Carbon Dioxide	Methane	Hexane +
WELL #216					
4/26	ND	4.40	54.77	37.83	ND
5/3	ND	21.83	47.24	27.93	ND
5/19	ND	21.36	38.52	37.12	ND
6/2	ND	37.13	29.44	30.43	ND
6/7	ND	22.31	40.68	33.32	0.69
6/28	ND	31.08	45.23	20.69	ND
WELL #257					
WELL #323					
4/26	ND	47.04	49.96	ND	ND
5/3	ND	63.42	33.58	ND	ND
5/19	ND	68.02	28.98	ND	ND
6/2	ND	65.29	31.71	ND	ND
6/7	ND	56.36	40.64	ND	ND
WELL #412					
4/26	ND	5.32	88.13	1.90	1.65
5/3	ND	53.64	43.17	ND	0.20
5/11	ND	28.36	68.64	ND	ND
5/19	ND	17.22	78.37	ND	1.31
5/24	ND	17.23	79.77	ND	ND
6/7	ND	25.19	74.81	ND	ND
6/28	ND	7.23	89.77	ND	ND
WELL #413					
4/26	ND	56.92	40.08	ND	ND
5/3	ND	74.35	22.65	ND	ND
5/11	ND	76.07	20.56	ND	0.37
5/19	ND	77.24	19.76	ND	ND
5/24	ND	74.71	22.29	ND	ND
6/2	ND	70.05	26.60	ND	0.34
6/7	ND	77.69	19.31	ND	ND

ND=Not determined in sample, although measured for.

TABLE 1-20 (Continued)
NONCONDENSIBLE GAS ANALYSIS, SAN ARDO
(mol %)

Date 1982	Oxygen	Nitrogen	Carbon Dioxide	Methane	Hexane +
WELL #414					
4/26	ND	24.35	71.81	ND	0.83
5/3	ND	51.26	45.75	ND	ND
5/11	ND	90.79	6.20	ND	ND
5/19	ND	73.52	23.48	ND	ND
5/24	ND	64.83	32.17	ND	ND
6/2	ND	54.24	42.77	ND	ND
6/7	ND	63.84	33.16	ND	ND
6/28	ND	12.73	84.27	ND	ND
WELL #415					
4/26	ND	76.50	20.50	ND	ND
5/3	ND	78.68	18.33	ND	ND
5/11	ND	80.66	16.34	ND	ND
5/24	ND	85.71	11.29	ND	ND
6/2	ND	80.75	16.25	ND	ND
6/7	ND	92.51	4.49	ND	ND
6/28	ND	50.16	45.96	0.88	ND

ND=Not determined in sample, although measured for.

TABLE 1-21

AVERAGE MONTHLY WATER CUT AT SAN ARDO

Well	1981 Sept.	Oct.	Nov.	Dec.	1982 Jan.	Feb.	Mar.	Apr.	May
A. Pattern Wells									
257	97	96	98	95	98	76	100	100	100
412	94	94	95	95	95	96	96	96	90
413	88	89	93	95	94	95	95	96	93
414	95	95	97	97	92	95	95	92	84
415	91	91	90	93	95	90	93	92	82
B. Second Ring Wells									
82	82	74	90	92	95	98	96	90	81
84	87	85	83	83	88	89	78	73	73
86	99	97	97	95	98	99	100	100	99
87	83	83	85	71	82	81	75	69	70
213	95	95	97	98	99	100	100	100	100
214	97	95	97	90	86	95	95	99	100
216	99	96	99	98	98	98	96	96	96
323	65	60	61	60	60	63	59	64	65

- Two pattern wells, Wells 414 and 415, showed a significant improvement in water cut starting in April and May, respectively.

- The water cut increased significantly at only three wells, Wells 213, 257, and 413, during the two tests.

Test 4 appears to have diverted steam to the west and south, leading to increased oil production and a decrease in the water cut of the second ring wells. No lowering of the water cut was measured in the pattern wells.

During Test 5, the second ring west and south wells continued to respond favorably and, starting in May, the corresponding pattern wells, Wells 414 and 415, showed a decrease in water cut.

d. Total Dissolved Solids

The total dissolved solids (TDS) content was measured frequently during the two tests at San Ardo. The TDS measurement can be significant because it is indicative of the source for the fluid reaching the well, as shown below:

	TDS, ppm
pure steam	0
formation water	5,000
blow-by water	10,000+

Texaco recycles the produced water to the steam generator. Assuming a steam quality of 65%, this feed water will produce steam with low TDS and condensate water of roughly 14,000 ppm. Thus, by analyzing the produced water at each well, it may be determined if a well is producing mostly steam (low TDS), condensate (high TDS) or formation water (about 5,000 ppm). Periodic sampling and analysis during the project will then detect any changes in the direction of the steam flow. Tables 1-22 and 1-23 show the results of TDS analyses for the produced

TABLE 1-22

TOTAL DISSOLVED SOLIDS: ppm

TEXACO, INC.

San Ardo Field Unit

PHASE I, TEST 4

Sample Date	Well Number												
	82A	84	86	87	213	214	216	257	323	412	413	414	415
09/09/81	5,570	1,890	310	---	430	5,520	1,300	270	5,140	7,460	5,060	4,890	15,600
10/01/81	6,320	1,590	---	1,000	230	5,140	1,300	90	---	7,320	7,520	4,320	13,800
10/13/81	5,130	---	---	970	245	---	---	---	---	---	---	---	14,500
10/22/81	---	6,640	---	---	---	5,840	---	340	---	---	4,770	4,100	---
11/27/81	7,300	1,810	---	880	---	6,200	---	---	4,050	4,360	5,550	3,590	14,800
12/05/81	7.590	1,760	---	820	370	---	790	390	4,040	8,590	5,500	3,310	13,800
12/22/81	10,300	1,770	---	1,280	1,280	---	1,200	1,260	5,570	10,900	7,600	---	12,400
01/19/82	10,600	2,050	---	1,160	4,840	---	1,010	---	---	---	7,800	7,100	16,100

TABLE 1-23

TOTAL DISSOLVED SOLIDS: ppm

TEXACO, INC.

San Ardo Field Unit

PHASE II, TEST 5

Sample Date	Well Number												
	82A	84	86	87	213	214	216	257	323	412	413	414	415
05/24/82	1,830	880	500	490	140	520	530	---	1,490	3,380	3,260	2,780	4,100
06/07/82	1,800	550	460	500	120	500	700	---	1,400	2,400	2,350	975	3,000
06/21/82	1,120	510	355	345	85	375	520	---	1,000	2,060	1,910	910	2,050
06/29/82	2,750	830	750	---	130	---	1,250	---	---	4,500	4,150	2,340	6,200

water from each well during Test 4 through January and Test 5 to the end of June, 1982.

The Test 4 results show that little or no change in the TDS occurred in seven of the 13 wells. (The October 22, 1982 figure for Well 84 is considered an error). In the six other wells, only minor changes occurred through mid-December. After that, steam was diverted toward the west and south, as the water cut measurements also showed.

- Well 414 (the south pattern well) was initially producing formation water. The TDS began to decline in October, 1981, reaching a low of about 3,300 ppm in December, implying that steam was being diverted to this well. By January, 1982, one month after the termination of injection, this trend had completely reversed, producing water with a TDS of 7,100 ppm.

- Well 415 (to the west) showed the same TDS decline and reversal as Well 414 with the difference that the initial TDS remained above 12,000 ppm which shows that the produced water was virtually all condensate.

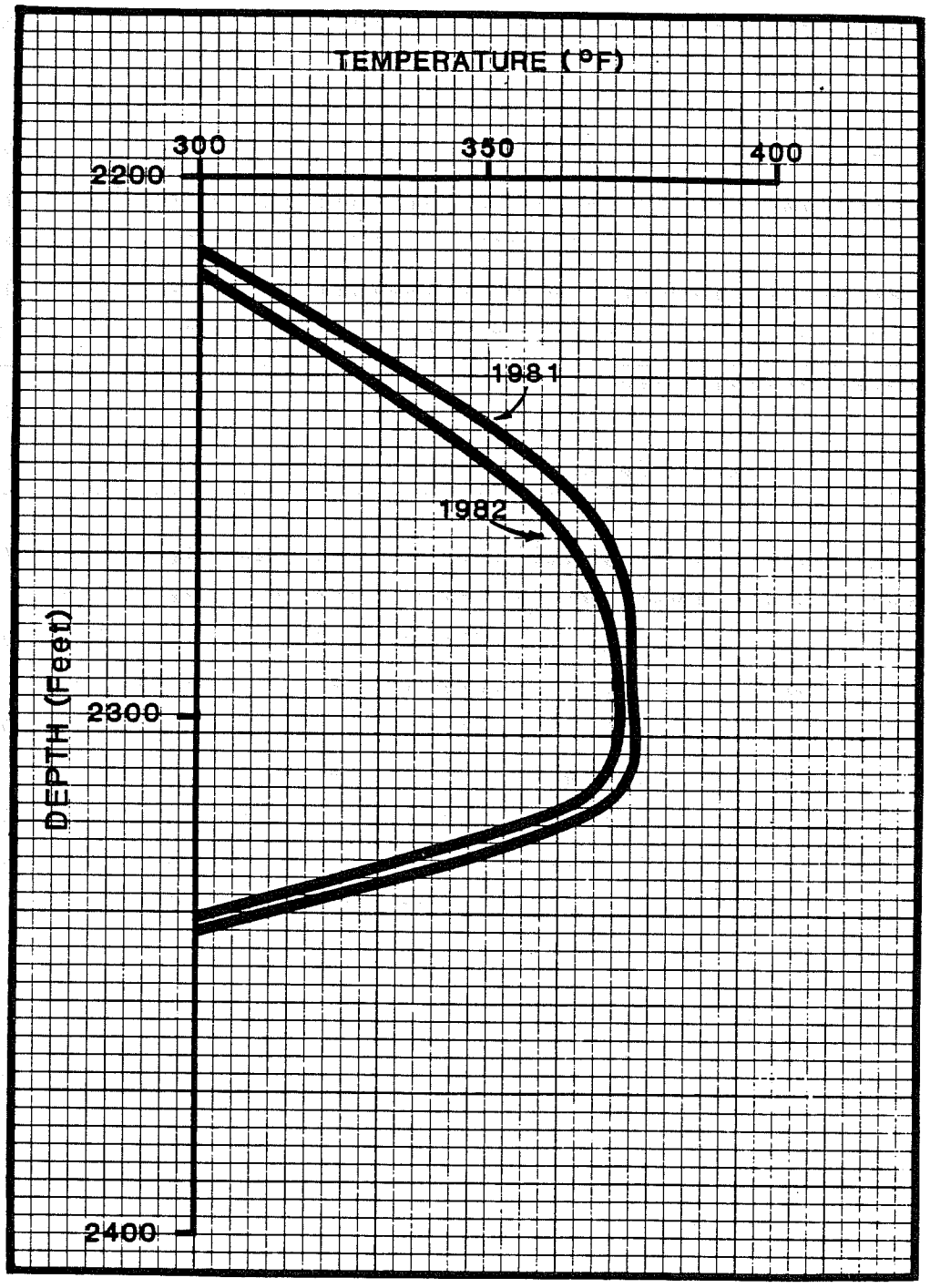
The TDS values obtained during Test 5 are strikingly different from Test 4. (A pattern well, Well 257, was shut in, so no TDS values are available for comparison.) By May 24, 1982, The TDS content of all the wells had decreased substantially; all wells tested were receiving steam to a greater or lesser amount. This decrease in TDS continued for each well for the samplings on June 7 and 21, 1982. On the June 29, 1982 sample date, two weeks following project termination, this trend was reversed in each of the nine wells sampled.

e. Temperature Surveys

Temperature logs for Well 330 from mid-July, 1981 and 1982, respectively, are shown in Figure 1-30. Comparison of the 1982 temperature log with one taken in July, 1981 shows no substantial difference.

Figure 1-30

TEMPERATURE LOG OF WELL 330 -- ROSENBERG 85A



The temperature log of July 12, 1982 for observation Well 330 indicates that there was a uniform temperature of about 380°F from 2,290 to 2,320 feet and that it falls off rapidly thereafter. Above 3,290 feet, the temperature decreases to 355°F at 2,250 feet and then falls off rapidly above that level.

Temperature surveys of producing wells (which were shut in for about three days prior to running the surveys) for the most part show little difference between July, 1981 and July, 1982. Only in three wells are some changes apparent: in Wells Rosenburg 414 and 415 the high temperature zone has extended downwards by ten to thirty feet, and steam has reached Rosenberg 216.

f. Injection Survey

In addition to this routine monitoring, steam injection surveys in Rosenberg 85A were taken over the course of the pilot test. They indicate a shift in the steam profile toward the bottom of the injection interval, Figure 1-31. This indicates a diversion of steam toward the bottom of the interval, and, if evident any significant distance into the formation, would indicate that steam override was being mitigated. However, these results might be misleading since they depend on the distribution of tracer between the vapor and liquid phase of the injected fluid which depends on the pressure-temperature relationship.

10. Surrounding Wells

In addition to monitoring injection and production for the pattern wells, steam parameters were measured on six surrounding steam injection wells. These wells served to confine the pattern. The location of these wells is indicated on Figure 1-23.

Injection into the surrounding wells ranged from 1,000 to 2,600 barrels per day, but remained relatively constant for each well, Table 1-24.

Figure 1-31

ROSENBERG 85A STEAM INJECTION PROFILE

(PICK-UP AT 2300')

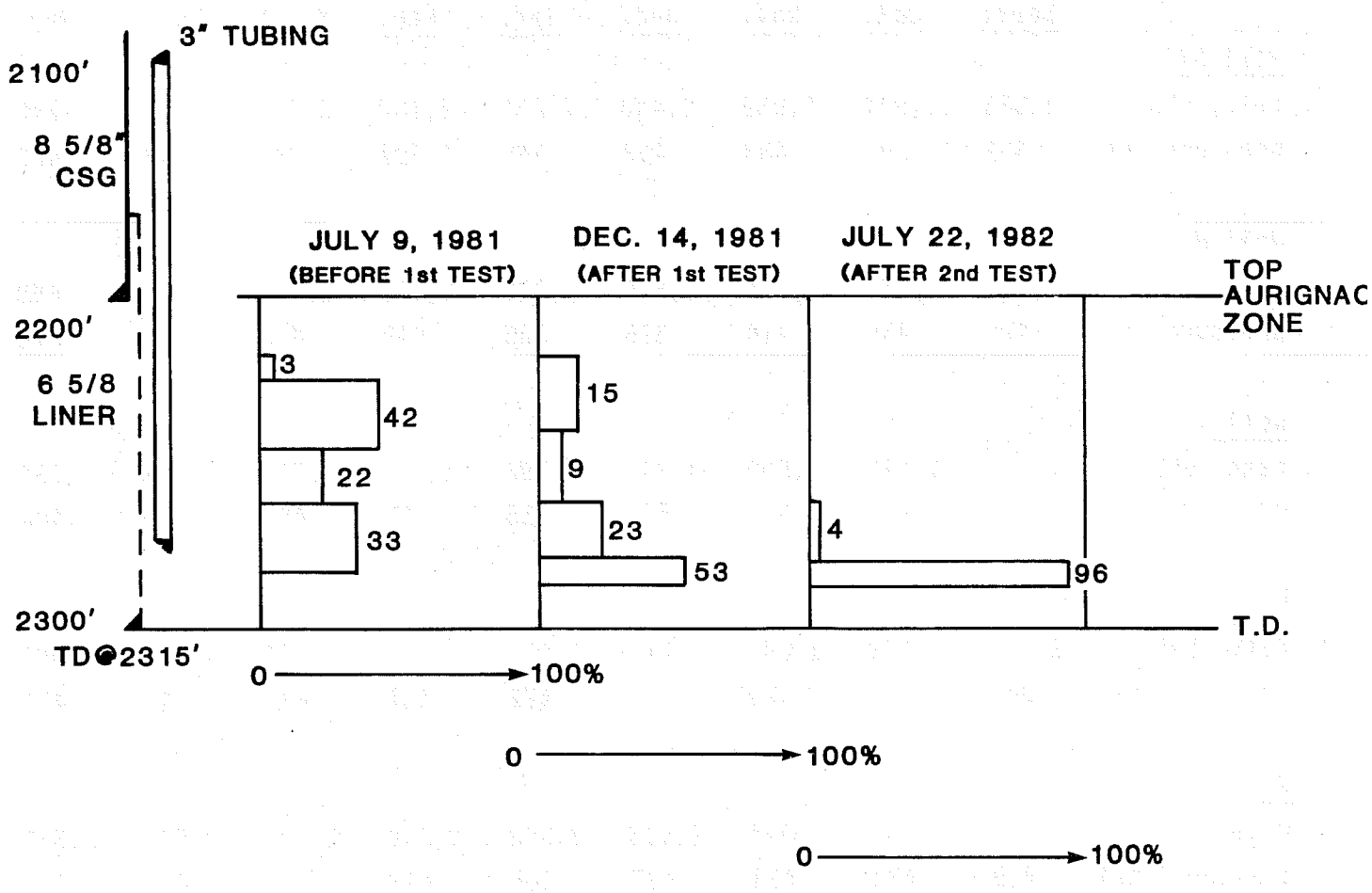


TABLE 1-24

SURROUNDING STEAM INJECTION WELLS

AVERAGE RATE AND PRESSURE

	1981				1982				
	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	March	April	May
Well 57									
rate, BPD	2,035	1,844	2,052	2,440	2,252	2,182	2,098	2,141	2,240
pressure, psi	438	393	433	463	448	397	392	406	422
Well 81									
rate, BPD	2,560	2,357	2,078	1,376	1,370	2,288	2,171	1,989	1,458
pressure, psi	475	456	414	325	326	419	408	395	318
Well 83									
rate, BPD	1,530	1,472	1,590	1,842	1,798	1,253	1,713	1,514	1,737
pressure, psi	478	452	489	542	525	454	484	445	484
Well 88									
rate, BPD	1,613	1,172	1,249	1,263	1,214	1,253	1,513	1,309	1,081
pressure, psi	342	341	376	497	472	454	477	510	488
Well 96A									
rate, BPD	2,017	1,932	2,094	2,616	2,398	2,210	1,904	2,528	2,561
pressure, psi	449	434	474	527	505	473	452	478	402
Well 100A									
rate, BPD	1,877	2,098	2,532	3,022	2,988	2,920	2,440	2,719	2,930
pressure, psi	423	413	439	500	482	458	451	474	481
Well 352									
rate, BPD		2,132	2,182	1,342	1,210	1,323	1,119	1,109	1,137
pressure, psi		348	377	494	497	477	445	492	513

Section 2

ANALYSIS OF FIELD PERFORMANCE MIDWAY-SUNSET

I. INTRODUCTION

The analysis of Section 1 examined the two steam with additives tests in the Midway-Sunset Field individually. A more complete analysis can be obtained by combining the two tests, including the effect on the larger surrounding area, since the second test was started before all the effects of the first test had disappeared. This is done in this section of the report.

Tracer surveys, casing head gas analysis, and gross fluid production measures show that the steam, chemicals, and air injected into Well 590 had an influence on surrounding second and third ring wells. Figure 2-1 shows the dominant direction of steam flow, and the area and the production wells which were influenced by the tests.

To quantify the overall performance and effect of the pilots, two base lines of measurement were derived:

- Comparison with historical performance. Base line data for 1979 and 1980, and its extrapolation into 1981/1982, provide a historical basis for comparing performance.

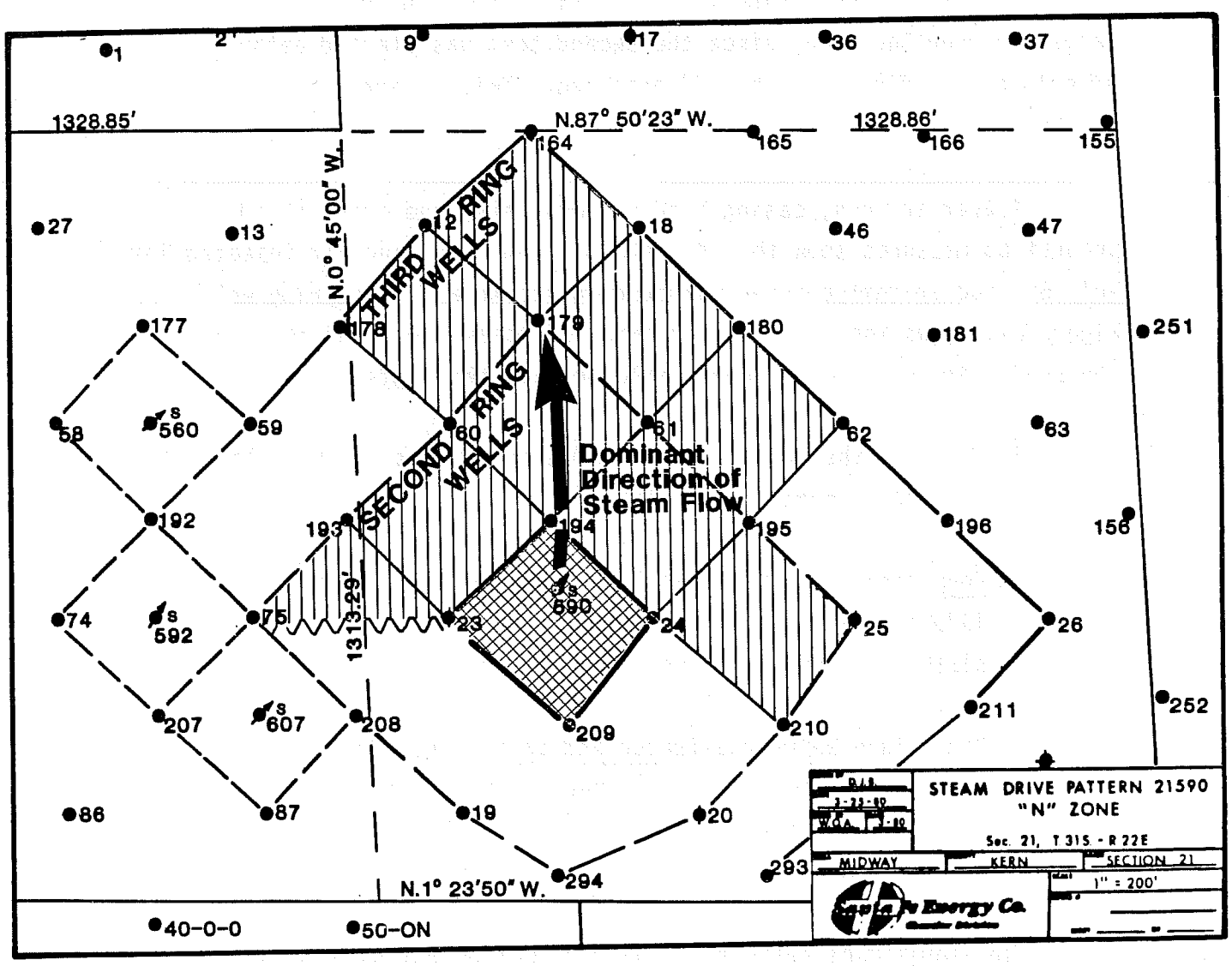
- Comparison between affected and control patterns. The nearby wells and patterns not affected by the injection of steam and chemicals provide a "control" group against which to measure the performance of the affected patterns.

The significant response in oil production and oil-steam ratio to the steam with additives tests in the pattern, as well as in some surrounding second and third ring patterns, are shown on Table 2-1. Total incremental oil recovered ranges from 111,000 to 120,000 barrels, depending on whether the pattern would have been abandoned as uneconomic or continue, if the tests had not been conducted.

Figure 2-1

AREA AFFECTED BY STEAM-WITH-ADDITIVES TESTS

(MIDWAY-SUNSET OIL FIELD)



Pattern 590-21

Area outside pattern affected by steam with additives tests

TABLE 2-1

MIDWAY-SUNSET TESTS OF STEAM WITH ADDITIVES - SUMMARY OF RESULTS

	Pattern 590-21*		Second Ring		Third Ring	
	1981	1982**	1981	1982**	1981	1982**
Incremental Oil (Bbls)	17,000-24,000	7,000-9,000	36,000	21,000	23,000	7,000
Oil-Steam Ratio						
• Total	0.14	0.20	0.29	0.33	0.66	0.30
• In Path of Steam	0.14	0.20	0.71	1.16	0.81	0.59
• Not in Path of Steam	--	--	0.19	0.05	0.51	0.26
Oil Production for Wells in Path of Steam						
• 1980 (Base Year)	31 B/D		61 B/D		61 B/D	
• 1981	72 B/D		147 B/D		110 B/D	
• 1982 (6 Months)	51 B/D		147 B/D		82 B/D	
Oil Production for Wells Not in Path of Steam						
• 1980 (Base Year)	--		27 B/D		130 B/D	
• 1981	--		15 B/D		104 B/D	
• 1982 (6 Months)	--		13 B/D		73 B/D	

* The range in production reflects uncertainty, from abandonment of the pattern to a continuance of the historic decline.

** 1982 - 6 Months

II. PERFORMANCE OF PATTERN 590-21 TO INJECTION OF STEAM WITH ADDITIVES

A. OVERALL PERFORMANCE

The three basic measures of performance--the oil-steam ratio, the oil cut, and the oil production rate--are shown on Figure 2-2. Three-month moving averages are used to smooth monthly variations in the data.

By all commonly used measures of field performance, Pattern 590-21 responded well to the steam with additives pilot tests:

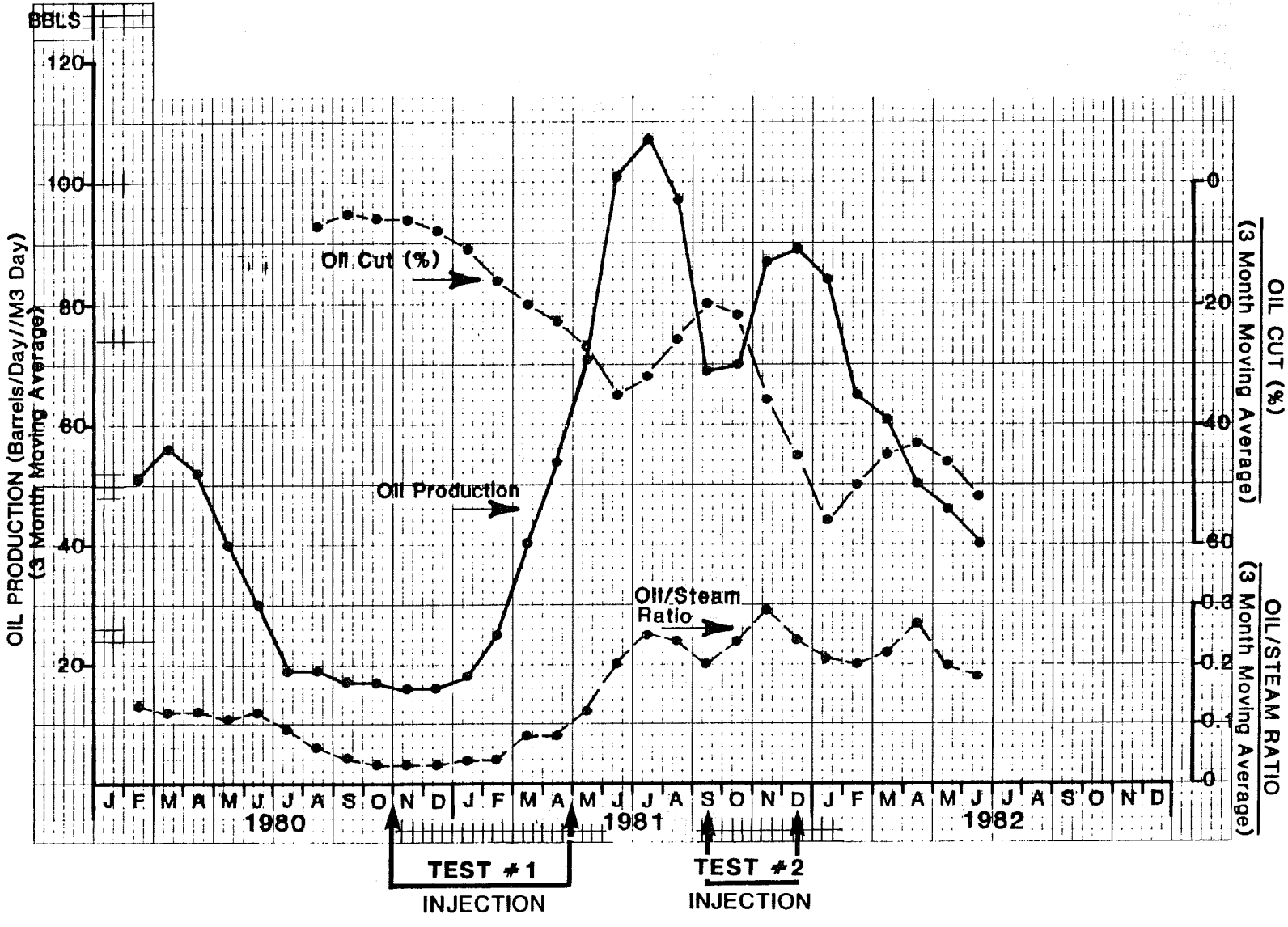
- The oil-steam ratio, the key measure of economic performance, ranged from 0.18 to 0.29 the last year of the test (July 1981 to June 1982), up from 0.04 at the end of 1980. An oil-steam ratio of above 0.16, especially for 50-60% quality steam, is generally recognized as a successful steam drive.

- The oil cut, a measure of the effective use of steam within an unconfined pattern (under steady-state conditions), ranged from 19% to 56% between mid-1981 and mid-1982, up from 6% at the end of 1980. For the first half of 1982, the oil cut was over 50%.

- Oil production peaked in mid-1981 at 107 barrels per day, up from a pre-treatment base of 18 barrels per day at the end of 1980. A second, though lower, peak of 89 barrels per day was observed at the end of 1981. Since then, following substantially reduced rates of steam injection, oil production declined to 40 barrels per day by June of 1982.

Figure 2-2

PERFORMANCE FROM PATTERN 590-21



- From 24,000 to 33,000 barrels of incremental oil have been produced over 18 months since the end of 1980 due to the injection of steam, chemicals, and air.

Figure 2-3 shows the quarterly averages for steam injection, net oil production, and gross fluid production. The supporting information is provided on Tables 2-2 and 2-3.

These data and findings are further discussed in the following.

B. OIL PRODUCTION

The historical oil production and steam injection for Pattern 590-21 is shown on Figure 2-4. The monthly steam injection and oil production since 1978 is shown on Figure 2-5.

Following injection of chemicals at the end of 1980, the oil production rate in Pattern 590-21 increased sharply in 1981. Oil production averaged nearly 2,000 barrels per month (66 barrels per day) in 1981, up four-fold from a base of 540 barrels per month (18 barrels per day) in the last six months of 1980, and 950 barrels per month (32 barrels per day) for all of 1980. In the first six months of 1982, oil production averaged 1,550 barrels per month (52 barrels per day), even though steam injection was sharply curtailed.

Incremental oil production in 1981 from Pattern 590-21 ranged from 17,000 barrels based on a decline curve, to 24,000 barrels, assuming the pattern would have been abandoned. Increased oil recovery in the first

Figure 2-3

STEAM INJECTION, GROSS FLUID PRODUCTION & NET OIL PRODUCTION -- Pattern 590-21

(Barrels per Day; Average per Quarter)

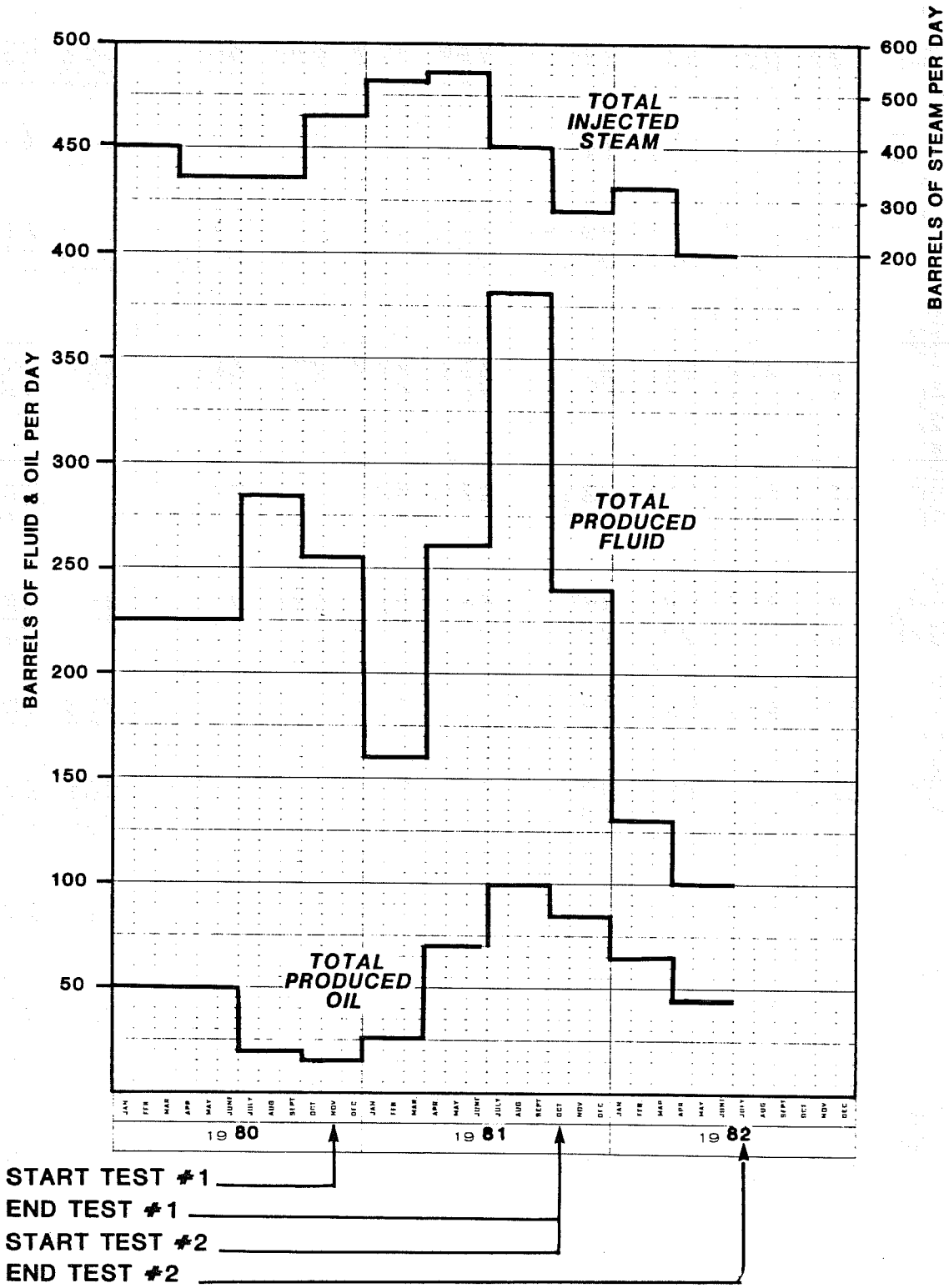


TABLE 2-2

SUMMARY OF PILOT PERFORMANCE

(Steam Drive w/Additives Test, Pattern 590-21, Midway-Sunset Field, California)

Month	OIL PRODUCTION Actual B/M*	OIL PRODUCTION Actual B/D*	OIL PRODUCTION 3 Mos. Avg. B/M	OIL PRODUCTION 3 Mos. Avg. B/D	CONTINUOUS STEAM INJECTION Actual BS/M	CONTINUOUS STEAM INJECTION Actual BS/D	CONTINUOUS STEAM INJECTION 3 Mos. Avg. BS/M	OIL-STEAM RATIO (v/v)** Actual	OIL-STEAM RATIO (v/v)** 3 Mos. Avg.	WATER PRODUCTION Actual BW/M	WATER PRODUCTION Actual BW/D	WATER PRODUCTION 3 Mos. Avg. BW/M	WATER PRODUCTION 3 Mos. Avg. BW/D	WATERCUT (%)*** Actual	WATERCUT (%)*** 3 Mos. Avg
1/80	847	47			6,000	200		0.14		318	20			27	--
2	2,027	70	1,545	51	15,600	510	12,200	0.15	0.13	2,663	92	1,864	66	57	55
3	1,762	58	1,712	56	15,000	490	14,600	0.12	0.12	2,611	86	3,722	157	60	68
4	1,348	48	1,580	52	13,200	430	13,700	0.10	0.12	5,893	293	6,025	233	81	79
5	1,615	53	1,171	40	13,000	450	10,200	0.12	0.11	9,570	319	7,814	291	86	87
6	550	19	923	30	4,500	150	7,500	0.12	0.12	7,978	260	7,954	258	94	90
7	603	19	590	19	5,000	160	6,700	0.12	0.09	6,314	196	7,269	264	91	92
8	618	20	599	19	10,500	350	10,200	0.06	0.06	7,514	335	7,391	265	92	93
9	575	19	506	17	15,100	500	13,300	0.04	0.04	8,346	264	8,172	297	94	95
10	325	11	493	17	14,400	470	14,900	0.02	0.03	8,656	292	7,750	253	96	94
11	580	20	486	16	15,300	500	14,300	0.04	0.03	6,248	204	7,190	236	92	94
12	552	18	461	16	13,300	440	15,500	0.04	0.03	6,665	213	5,548	186	92	92
Total-1980	11,402				140,900					72,776					
1/81	252	10	498	18	18,000	599	14,200	0.01	0.04	3,730	142	4,363	142	94	90
2	691	25	679	25	11,200	372	15,500	0.06	0.04	2,695	86	3,910	136	80	85
3	1,094	40	1,129	40	17,300	576	14,900	0.06	0.08	5,305	180	4,650	157	83	80
4	1,602	54	1,372	54	16,300	543	17,600	0.10	0.08	5,950	204	4,771	179	79	78
5	1,421	67	1,952	71	19,200	641	15,900	0.07	0.12	3,058	153	5,056	188	68	72
6	2,832	93	2,907	101	12,400	411	14,600	0.23	0.20	6,161	206	5,258	190	69	64
7	4,468	144	3,135	107	12,300	411	12,300	0.36	0.25	6,554	211	6,686	225	55	68
8	2,105	83	2,823	97	12,400	413	11,800	0.18	0.24	7,342	258	8,413	282	78	75
9	1,896	63	1,955	69	10,600	351	9,700	0.18	0.20	11,343	378	8,343	280	86	81
10	1,863	60	1,999	70	6,000	197	8,500	0.31	0.24	6,344	204	7,502	255	77	78
11	2,239	88	2,460	87	8,800	290	8,400	0.25	0.24	4,819	182	4,471	154	68	65
12	3,277	112	2,502	89	10,500	346	10,400	0.31	0.24	2,250	75	3,031	108	41	55
Total-1981	23,740				155,000					65,551					
1/82	1,990	67	2,407	84	11,800	393	11,600	0.17	0.21	2,024	66	1,914	66	50	44
2	1,953	74	1,874	65	12,500	417	9,500	0.16	0.20	1,468	58	2,031	66	43	52
3	1,679	54	1,724	61	4,200	140	7,700	0.40	0.22	2,602	75	2,197	74	61	56
4	1,539	56	1,429	50	6,500	217	5,300	0.24	0.27	2,520	89	1,977	65	62	58
5	1,069	41	1,221	46	5,200	173	6,100	0.21	0.20	810	32	1,477	54	43	55
6	1,056	40	1,062	40	6,700	223	6,000	0.16	0.18	1,103	41	956	37	51	47
Total-1982	9,286				46,900					10,527					

* Barrels per month measures total oil produced for the month; barrels per day measures daily oil production for days wells are on line.

** Oil-steam ratio based on barrels per month data.

*** Actual watercut based on barrels per month data; 3 month average watercut based on barrels per day data.

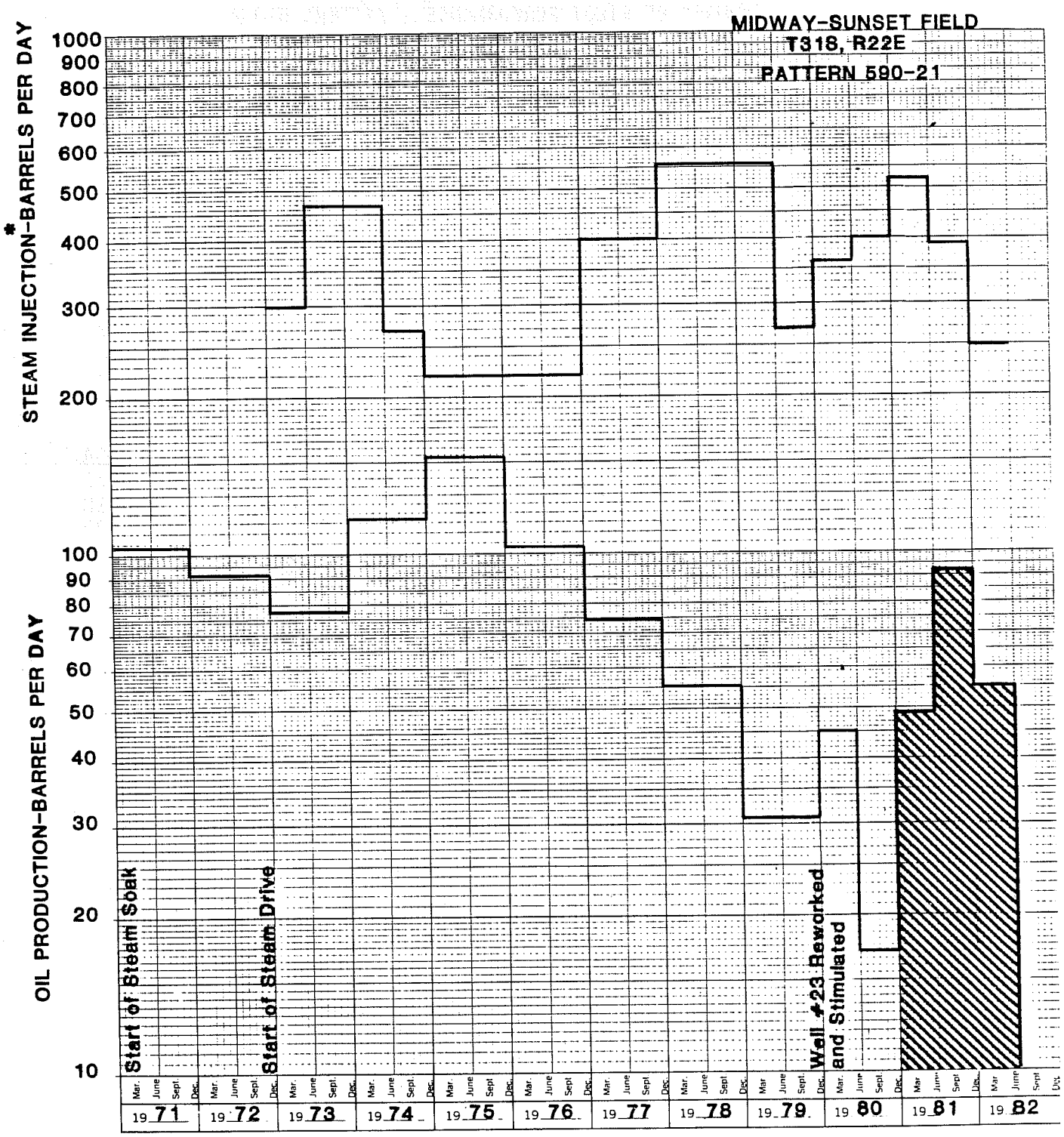
TABLE 2-3

SUMMARY OF PILOT PERFORMANCE - PATTERN 590-21
(QUARTERLY AVERAGES)

	Oil Production (B/M)	Total Fluid Production (B/M)	Oil-Cut (%)	Steam Injection (B/M)	Oil-Steam Ratio (v/v)
1979	1,120			14,800	0.08
1980					
1st Q	1,545	3,409	45	12,200	0.13
2nd Q	1,171	8,985	13	10,200	0.11
3rd Q	599	7,990	7	10,200	0.06
4th Q	486	7,675	6	14,300	0.03
Avg	950	7,017	14	11,200	0.08
1981					
1st Q	679	4,589	23	15,500	0.04
2nd Q	1,952	7,008	30	16,000	0.12
3rd Q	2,823	11,236	25	15,800	0.18
4th Q	2,460	6,931	35	12,400	0.20
Avg	1,978	7,441	27	14,900	0.14
1982					
1st Q	1,874	3,905	48	9,500	0.19
2nd Q	1,221	2,699	45	6,100	0.20
Avg	1,548	3,302	47	7,800	0.20

Figure 2-4

HISTORY OF OIL PRODUCTION AND STEAM INJECTION
(PATTERN 590-21)



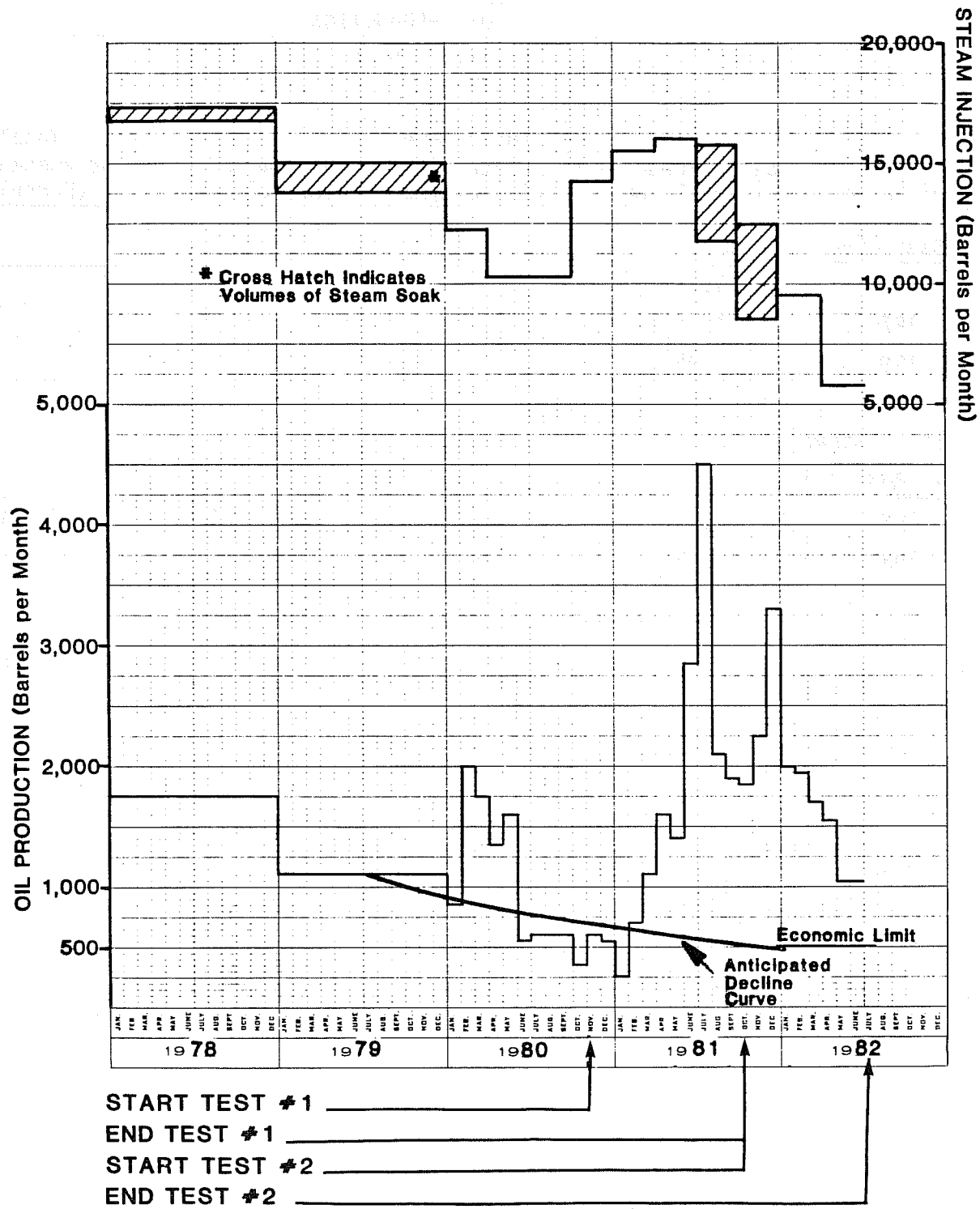
* PLUS FROM 50 TO 80 BARRELS PER DAY OF STEAM SOAK THROUGH 1976

OIL PRODUCTION DURING PILOT TESTS.

Figure 2-5

OIL PRODUCTION AND STEAM INJECTION (BBL/MONTH)

(PATTERN 590-21)



six months of 1982 ranged from 7,000 to 9,000 barrels. The calculations are summarized below:

CALCULATION OF INCREMENTAL OIL PRODUCTION

(Pattern 590-21)

Time Period	Actual Production (Barrels/Mo.)	Anticipated Production* (Barrels/Mo.)	Incremental Oil (Barrels/Mo.)	Total Incremental Oil (Barrels)
A. Base Line				
1978	1,750			
1979	1,120			
1980	950			
B. Since Steam w/ Additives				
1981	1,980	0-600	1,380-1,980	17,000-24,000
1982 (6 mos.)	1,550	0-400	1,150-1,550	7,000- 9,000

*Range in anticipated production reflects abandoned pattern to anticipated decline.

Oil production by well for the four Pattern 590-21 wells is shown on Figure 2-6 and Tables 2-4 and 2-5. The best performance by far has been from Well 194, in the north quadrant of the pattern. The least incremental response, although still a significant oil production, was from the updip Well 23 in the east quadrant where past oil recovery had already been very high, estimated at about 80% of the oil in-place. The increase in production during 1980 is due to steam stimulation of well 23 at the beginning of the year.

Figure 2-6

HISTORY OF OIL PRODUCTION IN PATTERN 590-21 BY PRODUCTION WELL

(1971-MID 1982)

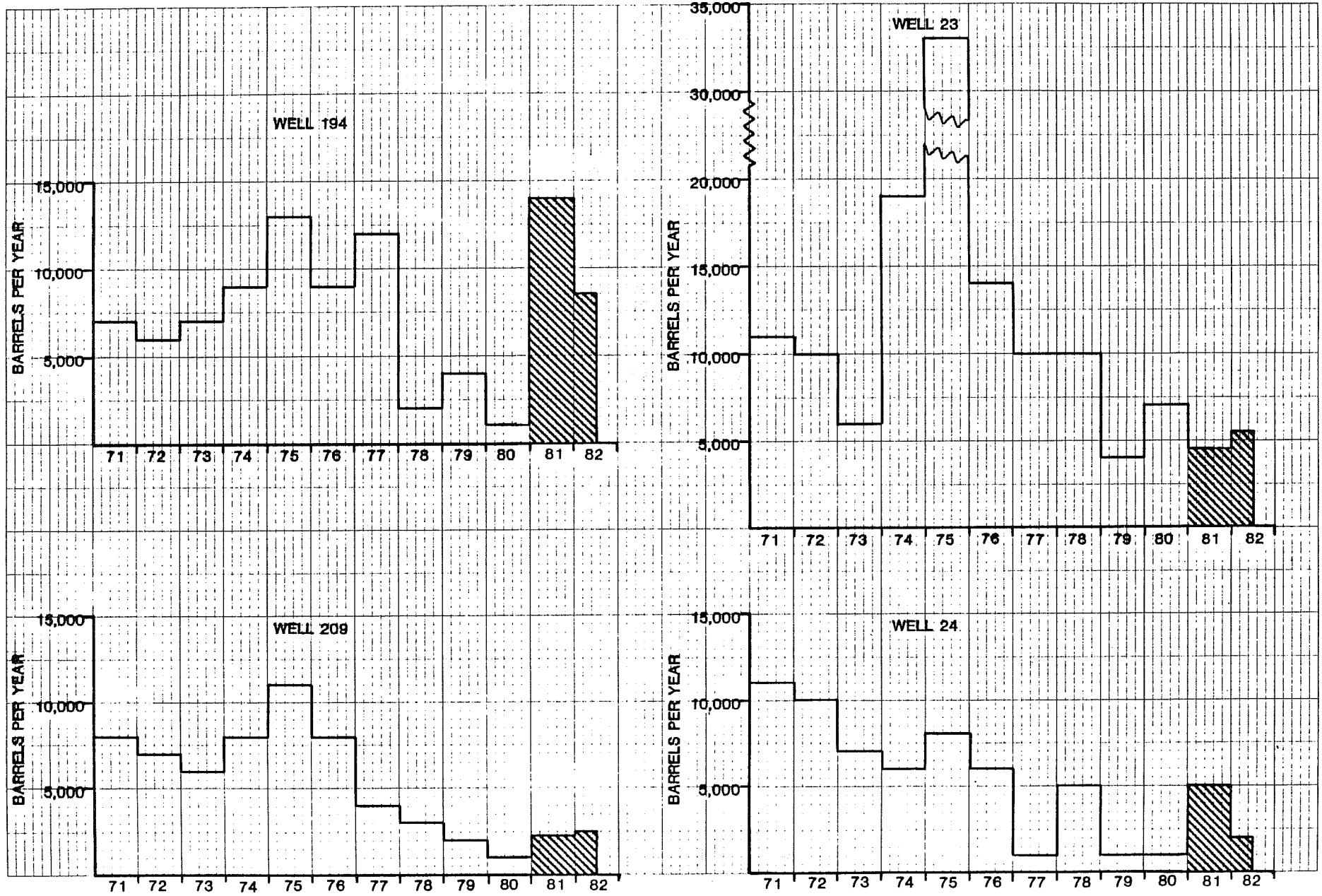


TABLE 2-4

MONTHLY OIL AND WATER PRODUCTION FROM PILOT PATTERN, 590-21

(Barrels of Oil or Water Per Month)

MONTH	WELL 23 BOPM	WELL 23 BWPM	WELL 23 % WATER (v/v)	WELL 24 BOPM	WELL 24 BWPM	WELL 24 % WATER (v/v)	WELL 194 BOPM	WELL 194 BWPM	WELL 194 % WATER (v/v)	WELL 209 BOPM	WELL 209 BWPM	WELL 209 % WATER (v/v)	TOTAL PATTERN ACTUAL BOPM	TOTAL PATTERN ACTUAL BWPM	TOTAL PATTERN ACTUAL % WATER (v/v)	TOTAL PATTERN 3 MONTHS MOVING AVG. 3 MOS. OIL	TOTAL PATTERN 3 MONTHS MOVING AVG. 3 MOS. WATER	TOTAL PATTERN 3 MONTHS MOVING AVG. 3 MOS. WATERCUT(%) (v/v)
1/80	796	144	15	ND	ND	--	10	162	94	41	12	23	847	318	27			
2/80	1,585	744	32	320	183	36	27	1,674	98	81	62	43	2,027	2,663	57	1,545	1,864	55
3/80	1,430	744	34	265	168	39	37	1,674	98	30	25	45	1,762	2,611	60	1,712	3,722	68
4/80	1,195	628	34	36	1,896	98	60	2,160	97	57	1,209	95	1,348	5,893	81	1,580	6,025	79
5/80	919	354	28	130	3,115	96	169	5,054	97	397	1,047	73	1,615	9,570	86	1,171	7,814	87
6/80	50	1,065	96	85	1,945	96	204	4,571	96	211	397	65	550	7,978	94	923	7,954	90
7/80	135	807	86	89	1,261	93	200	3,991	95	179	255	59	603	6,314	91	590	7,269	92
8/80	276	484	64	93	2,188	96	66	4,400	99	183	442	71	618	7,514	92	599	7,391	93
9/80	49	550	92	61	2,203	97	128	5,016	98	337	577	63	575	8,346	94	506	8,172	94
10/80	25	1,005	98	11	1,822	99	64	5,457	99	225	372	62	325	8,656	96	493	7,750	94
11/80	78	784	91	150	1,158	89	306	3,967	93	46	339	88	580	6,248	92	486	7,190	94
12/80	215	621	74	101	1,658	94	189	3,766	95	47	620	93	552	6,665	92	461	5,548	92
Total	6,753	7,930	54 (avg)	1,341	17,597	93 (avg)	1,460	41,892	97 (avg)	1,834	5,357	75(avg)	11,402	72,776	87(avg)	10,066	70,699	88(avg)
1/81	98	283	80	3	493	99	108	2,710	96	43	145	77	252	3,631	94	498	4,363	90
2/81	346	280	45	267	1,258	82	43	964	96	35	193	85	691	2,695	80	679	3,910	85
3/81	180	710	80	239	1,499	86	616	2,918	83	59	178	75	1,094	5,305	83	1,129	4,650	80
4/81	36	545	94	172	1,477	90	1,327	3,774	74	67	154	70	1,602	5,950	79	1,372	4,771	78
5/81	183	359	66	205	411	67	907	2,257	71	126	31	20	1,421	3,058	68	1,952	5,056	72
6/81	310	291	48	523	833	61	1,874	4,911	72	125	126	50	2,832	6,161	69	2,907	5,258	64
7/81	499	319	39	610	1,109	65	3,134	5,004	61	225	122	35	4,468	6,554	59	3,135	6,686	68
8/81	163	97	37	548	1,078	66	1,326	6,014	82	68	153	69	2,105	7,342	78	2,823	8,413	75
9/81	419	450	52	65	843	93	1,203	5,608	82	209	4,442	96	1,896	11,343	86	1,955	8,343	81
10/81	569	894	61	405	1,531	79	610	3,391	85	279	528	65	1,863	6,344	77	1,999	7,502	79
11/81	726	663	48	587	2,172	79	565	1,693	75	361	291	45	2,239	4,819	68	2,460	4,471	64
12/81	773	373	33	857	703	45	1,295	1,034	44	352	140	29	3,277	2,250	41	2,502	3,031	55
Total	4,301	5,264	55 (avg)	4,481	13,407	75 (avg)	13,008	40,278	76 (avg)	1,949	6,503	77(avg)	23,740	65,452	73(avg)	23,411	66,454	74(avg)
1/82	578	334	37	557	799	59	855	891	51	ND	ND	--	1,990	2,024	50	2,407	1,914	44
2/82	355	325	48	209	306	59	823	519	39	556	318	36	1,943	1,468	43	1,874	2,031	52
3/82	569	348	38	48	1,400	97	801	676	46	261	178	41	1,679	2,602	61	1,724	2,197	56
4/82	498	98	16	56	1,506	96	811	812	50	174	104	37	1,539	2,520	62	1,429	1,977	58
5/82	451	254	36	76	182	71	446	326	42	96	48	33	1,069	810	43	1,221	1,478	55
6/82	206	270	57	180	300	62	536	449	40	134	84	38	1,056	1,103	51	1,062	956	47
Total	2,657	1,629	38 (avg)	1,126	4,493	80 (avg)	4,272	3,673	46 (avg)	1,221	732	37(avg)	9,276	10,527	53(avg)	9,717	10,553	52(avg)

TABLE 2-5

DAILY OIL AND WATER PRODUCTION FROM PILOT PATTERN, 590-21

(Barrels of Oil or Water Per Day)

MONTH	WELL 23 BOPD	WELL 23 BWPD	WELL 24 BOPD	WELL 24 BWPD	WELL 194 BOPD	WELL 194 BWPD	WELL 209 BOPD	WELL 209 BWPD	TOTAL PATTERN ACTUAL BOPD	TOTAL PATTERN ACTUAL BWPD	TOTAL PATTERN ACTUAL Total Fluid	TOTAL PATTERN ACTUAL % WATER	3 MONTHS MOVING AVERAGE 3 MOS. OIL	3 MONTHS MOVING AVERAGE 3 MOS. WATER	3 MONTHS MOVING AVERAGE 3 MOS. WATERCUT, % (v/v)
1/80	44	8	-	-	1	11	2	1	47	20	67	70			
2/80	55	26	11	6	1	58	3	2	70	92	162	57	58	66	53%
3/80	46	24	9	6	1	54	2	2	58	86	144	60	59	157	73%
Avg									58	66	124	53			
4/80	40	21	2	119	2	72	4	81	48	293	341	86	53	233	81%
5/80	30	11	5	111	5	163	13	34	53	319	372	86	40	296	88%
6/80	2	23	3	74	7	150	7	13	19	260	279	94	30	266	90%
Avg									40	291	331	88			
7/80	4	26	3	41	6	129	6	8	19	204	223	91	19	241	93%
8/80	9	16	3	71	2	142	6	14	20	243	263	92	19	241	93%
9/80	2	18	2	73	4	167	11	19	19	277	296	94	17	267	94%
Avg									19	265	284	93			
10/80	1	32	0	59	2	176	8	14	11	281	292	96	17	255	94%
11/80	3	26	5	39	10	132	2	11	20	208	228	91	16	235	94%
12/80	7	21	3	53	6	121	2	20	18	215	233	92	16	186	92%
Avg									16	236	252	94			
1/81	4	17	0	19	4	93	2	5	10	134	144	93	18	148	89%
2/81	12	10	10	45	2	34	1	7	25	96	121	79	25	140	85%
3/81	6	23	8	50	24	112	2	6	40	191	231	83	40	164	80%
Avg									25	136	161	84			
4/81	1	18	6	53	44	126	3	7	54	204	258	79	54	183	77%
5/81	6	12	7	15	50	125	4	1	67	153	220	70	71	188	73%
6/81	10	10	17	28	62	164	4	4	93	206	299	69	101	190	65%
Avg									71	188	259	73			
7/81	16	10	20	36	101	161	7	4	144	211	355	59	107	225	68%
8/81	11	6	24	47	43	194	5	11	83	258	341	76	97	282	74%
9/81	14	15	2	28	40	187	7	148	63	378	441	86	69	280	80%
Avg									97	282	379	74			
10/81	18	29	13	49	20	109	9	17	60	204	264	77	70	255	78%
11/81	24	22	20	72	25	74	19	15	88	183	271	68	87	154	64%
12/81	25	12	30	24	42	33	15	6	112	75	187	40	89	108	55%
Avg									87	154	241	64			
1/82	19	10	20	28	28	28	ND		67	66	133	50	84	66	44%
2/82	13	11	10	16	29	19	22	12	74	58	132	44	65	66	50%
3/82	18	12	2	45	26	12	8	6	54	75	129	58	61	74	55%
Avg									65	66	131	50			
4/82	17	3	2	54	27	27	10	5	56	89	145	61	50	65	57%
5/82	15	8	4	8	17	13	5	3	41	32	73	44	46	54	54%
6/82									40	40	80	51	41	36	47%
Avg									46	54	100	54			

The lowest absolute oil recovery was from Well 209 in the south quadrant. Very little of the injected steam appears to have reached this well, as evidenced by the low levels of production and continuing low bottom hole and flow-line temperatures.

C. STEAM INJECTION

The decrease in oil production in the initial months of 1982 appears due to considerably lower steam injection rates. Injection that had averaged nearly 16,000 barrels per month (500 B/D), including steam soak, during the first nine months of 1981 was progressively reduced to 12,400 B/Mo. (410 B/D) in the last quarter of 1981, 9,500 B/Mo. (310 B/D) in the first quarter of 1982, and 5,800 B/Mo. (200 B/D) for the second quarter of 1982, as tabulated below:

STEAM INJECTION RATES
(Pattern 590-21)

	Steam Injection, B/Yr			Total Injection Rate	
	Drive	Soak	Total	(B/Mo.)	(B/D)
1978	196,000	7,000	203,000	16,900	560
1979	151,000	27,000	175,000	14,800	490
1980					
1Q	36,600	-	36,600	12,200	
2Q	30,700	-	30,700	10,200	
3Q	30,600	-	30,600	10,200	
4Q	43,000	-	43,000	14,300	
TOTAL	141,000	-	141,000	11,200	390
1981					
1Q	46,500	-	46,500	15,500	
2Q	47,800	-	47,800	16,000	
3Q	35,300	12,000	47,300	15,800	
4Q	25,300	12,000	37,300	12,400	
TOTAL	155,000	24,000	179,000	14,900	500
1982					
1Q	28,500	-	28,500	9,500	310
2Q	18,400	-	18,400	6,100	200

D. OIL-STEAM RATIO

The oil-steam ratio began a steady rise in February, 1981, three months after the start of chemical and gas injection. It increased dramatically in June 1981, to 0.2, and stayed at or above 0.19 throughout the tests, as shown on Figure 2-7.

The quarterly oil-steam ratios for Pattern 590-21 (with and without steam soak) are shown below:

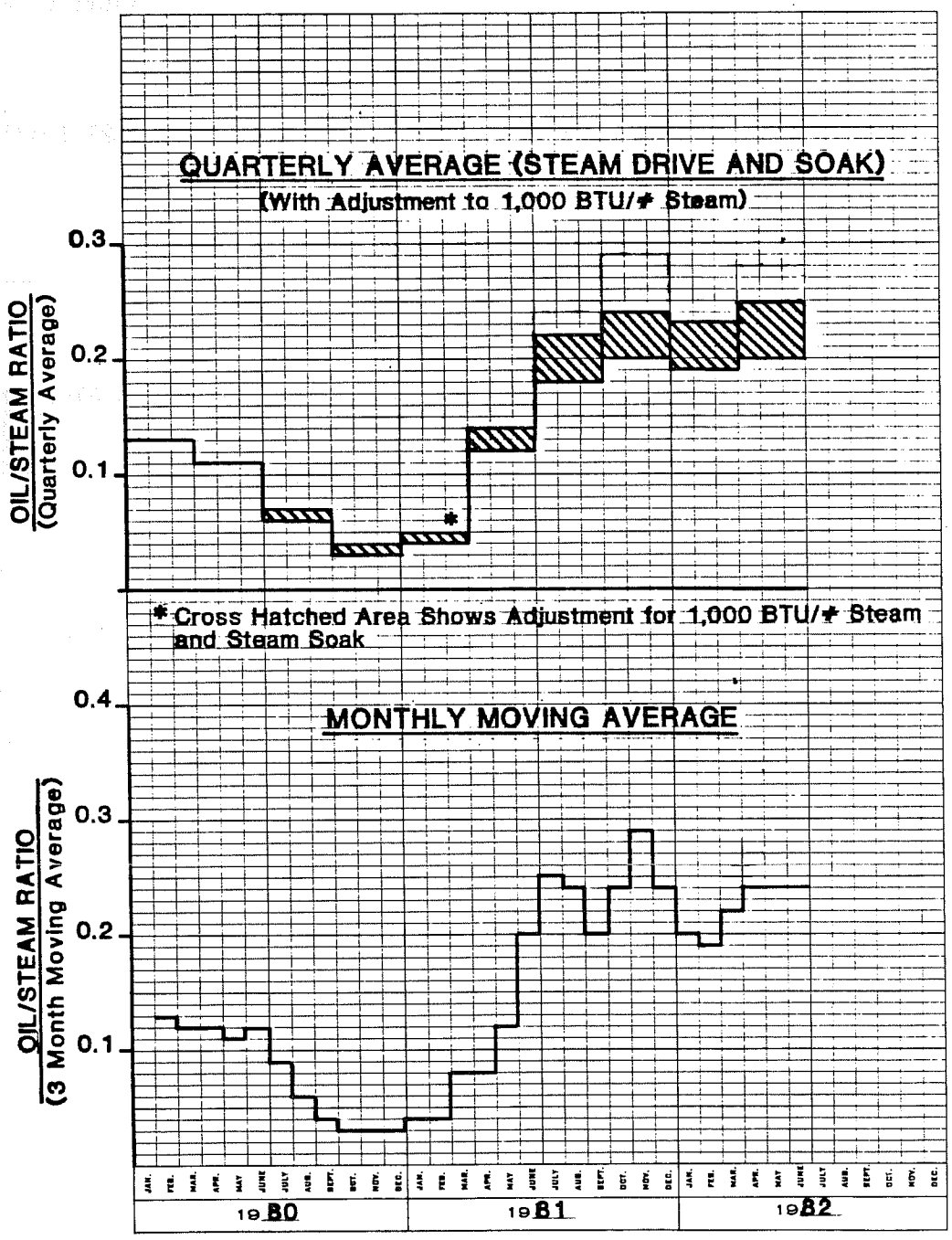
OIL-STEAM RATIO (Pattern 590-21)

	Steam Drive	Steam Drive Plus Steam Soak	
	(As Reported)	(As Reported)	(Adjusted to 1,000 BTU/#)*
1980			
3Q	0.06	0.06	0.07
4Q	0.03	0.03	0.04
1981			
1Q	0.04	0.04	0.05
2Q	0.12	0.12	0.14
3Q	0.24	0.18	0.22
4Q	0.29	0.20	0.24
1982			
1Q	0.19	0.19	0.23
2Q	0.20	0.20	0.24

* Based on a comparison of injected heat (energy).

Figure 2-7

OIL-STEAM RATIO
(PATTERN 590-21)



Since the injected steam is 50 to 60% quality, and estimated at about 830 BTU/lb, the measured oil-steam ratios should be multiplied by 1.2 to reach a standard of 1,000 BTU/lb steam for comparison purposes. With this adjustment, the oil-steam ratio (continuous plus soak), was between 0.22 and 0.24 for the last 12 months of the tests, as shown in the last column of the above table and on Figure 2-7. Thus, there has been a very positive net energy ratio of about 4 BTUs of oil out per 1 BTU of heat in.

E. FLUID BALANCE

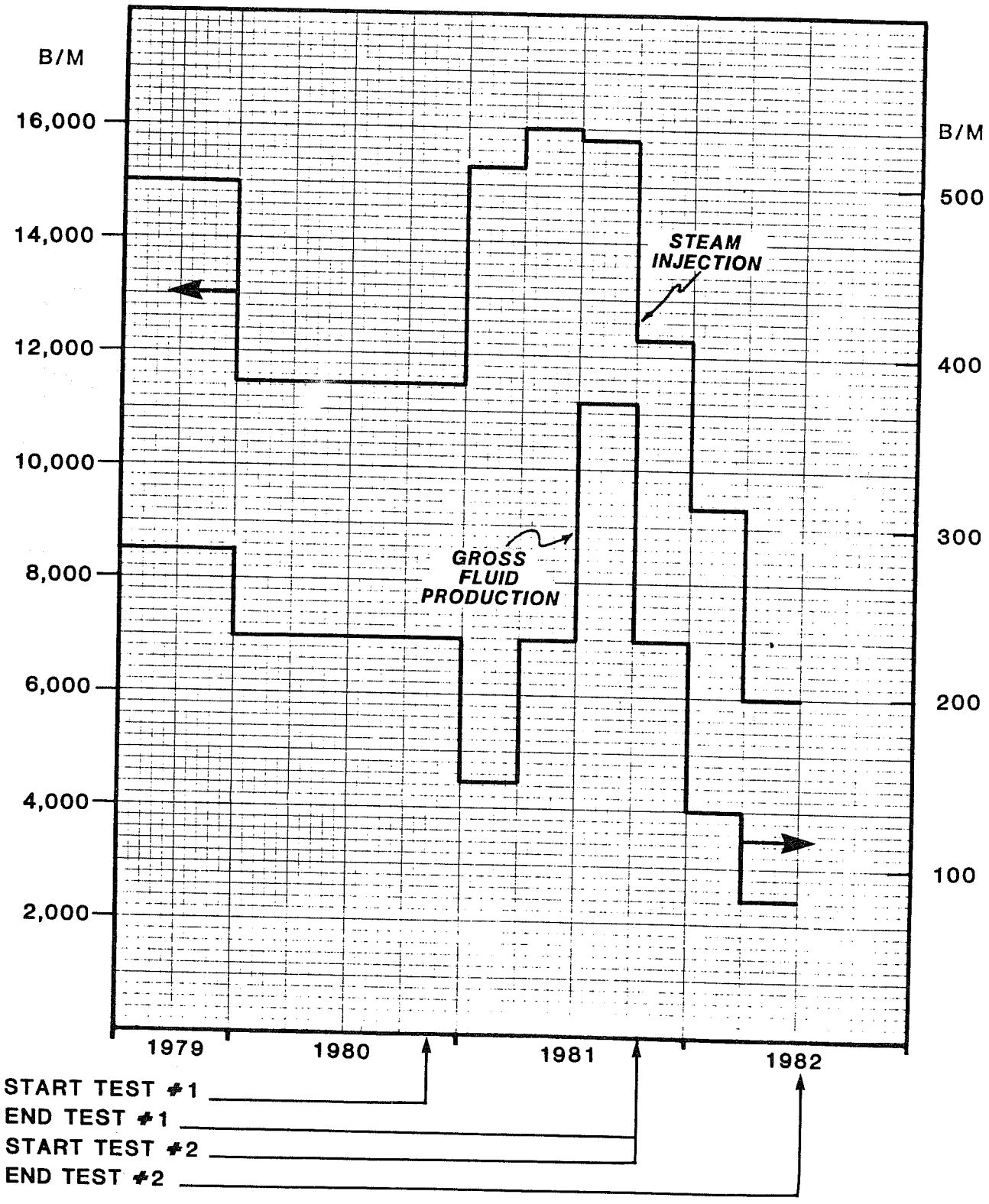
Much of the injected steam is being diverted from the inside Pattern 590-21 and stimulating increased oil production in the second and third ring wells. The fluid balance shows that since mid-1981, only about 50% of the injected steam has been produced from or remained in Pattern 590-21, as summarized on Figure 2-8 and below:

Month	Total Steam Injection (B/Mo.)	Gross Fluid Production (B/Mo.)
September, '81	22,600*	13,200
October	18,000*	8,200
November	8,800	7,100
December	10,500	5,500
January, '82	11,800	4,000
February	12,500	3,400
March	4,200	4,300
April	6,500	4,100
May	5,200	1,900
June	6,700	2,200
Total	106,800	53,900

*Steam soak of 24,000 barrels in August/September allocated for timing purposes to September/October.

Figure 2-8

FLUID BALANCE -- Pattern 590-21
Steam Injection vs. Gross Fluid Production



F. EFFECTIVE OIL-STEAM RATIO

Because of the large fluid imbalance, an effective oil-steam ratio was estimated for Pattern 590-21 using the oil cut as a proxy for the oil-steam ratio. This assumes the steam that was effective in the pattern equals the produced water plus the steam/water required to fill the pore space vacated by the produced oil.

This is equivalent to subtracting amounts of steam, equal to the difference between the gross fluid production and total steam injection from Pattern 590-21, and allocating it to the surrounding patterns. The two components of this effective oil-steam ratio, the gross fluid production and the net oil production, are shown on Figure 2-9.

The oil cut, as shown on Figure 2-10, increased from a base of 5 to 8% at the end of 1980 to over 20% in early 1981, 30% in mid-1981, and to nearly 50% by late 1981. Overall, the oil cut averaged 27% in 1981 and 47% in 1982 (first half). The quarterly and yearly oil cuts after 1979 are shown below:

OIL CUT
(Pattern 590-21)

Time Period	Oil	Water	Oil Cut (%)
1980 - 1Q	4,636	5,592	45
- 2Q	3,513	23,441	13
- 3Q	1,796	22,174	7
- 4Q	1,457	21,569	6
Total	11,402	72,776	14 (avg)
1981 - 1Q	2,037	11,730	23
- 2Q	5,855	15,169	30
- 3Q	8,469	25,239	25
- 4Q	7,379	13,413	35
Total	23,740	65,551	27 (avg)
1982 - 1Q	5,622	6,094	48
- 2Q	3,664	4,433	45
Total	9,286	10,527	47 (avg)

Figure 2-9

GROSS FLUID AND NET OIL PRODUCTION
Pattern 590-21

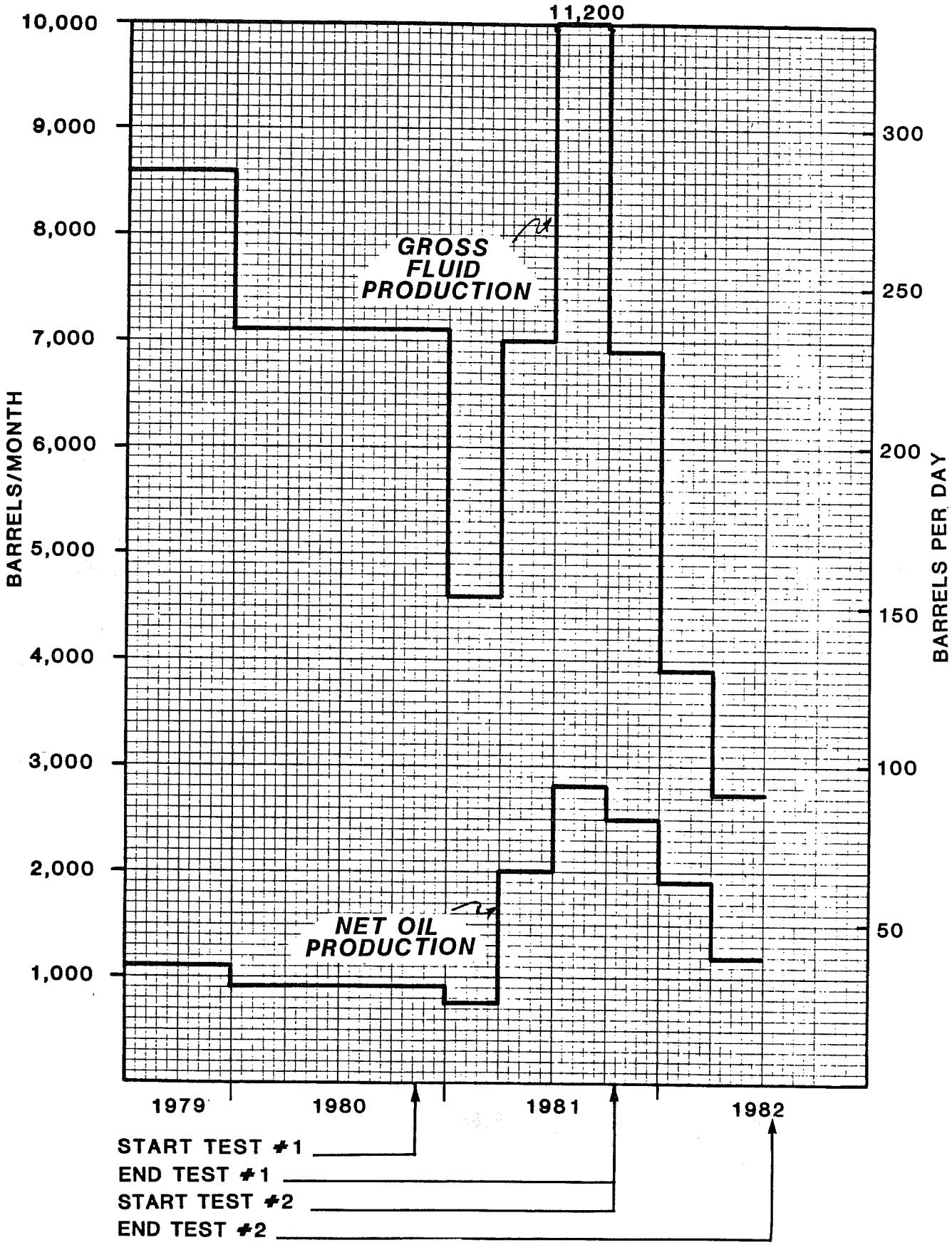
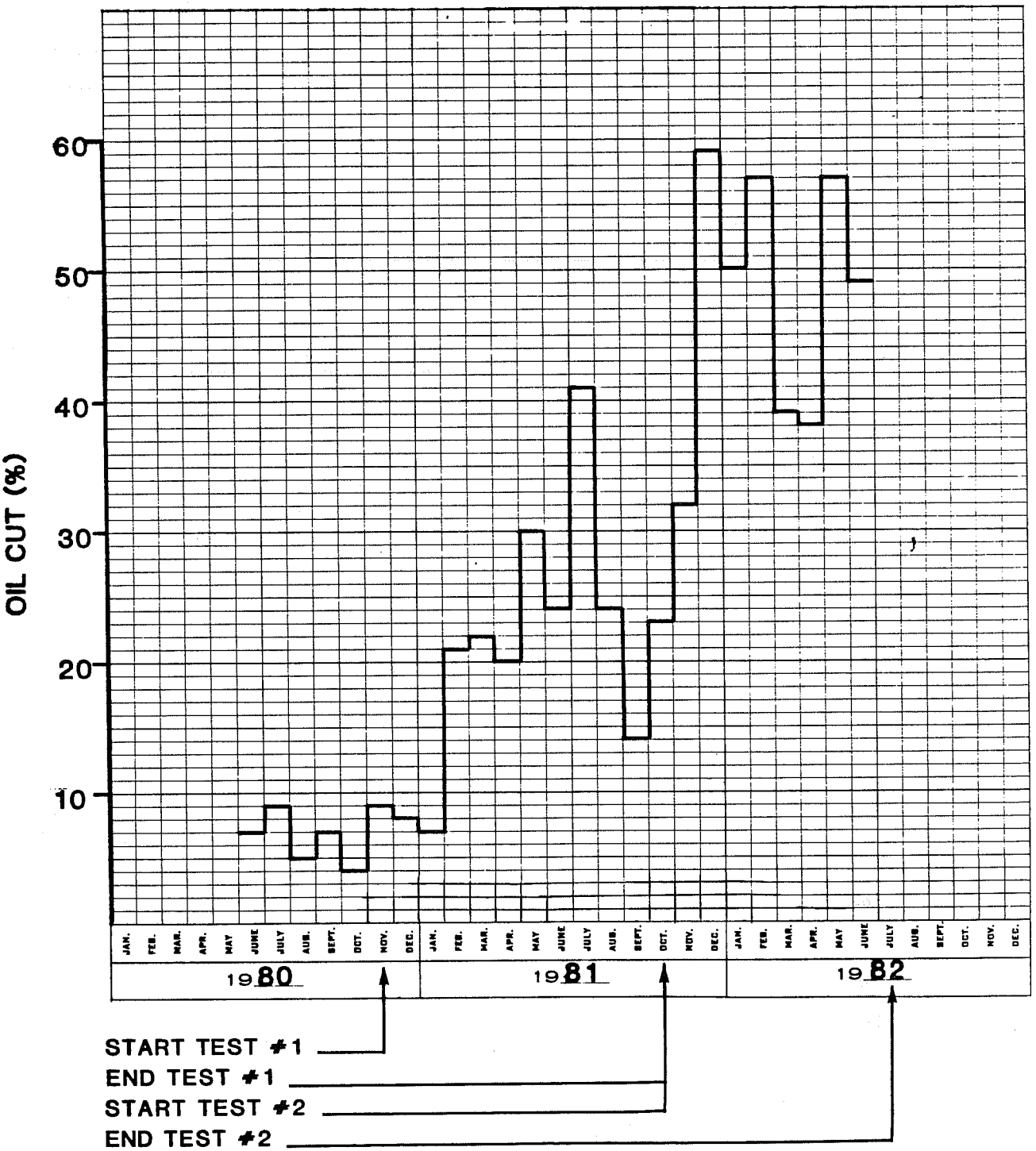


Figure 2-10

OIL CUT (%)

(PATTERN 590-21)



Additional key data on the performance of Pattern 590-21 are provided in Table 2-6.

The last three columns of Table 2-6 show the unadjusted oil-steam ratio, the fluid balance, and the resulting adjusted oil-steam ratio. The overall fluid balance is about 50%, and the adjusted oil-steam ratio is 0.47 in the first half of 1982; up from 0.13 in the pre-pilot period of 1979.

TABLE 2-6

CALCULATION OF ADJUSTED OIL-STEAM RATIO -- PATTERN 590-21

	Gross Fluid (Bbls)	Net Oil (Bbls)	Oil Cut, % v/v	Injected Steam (Bbls)	Oil-Steam Ratio v/v	Fluid Balance v/v	Adjuste Oil-Ste Ratic v/v
A. Pre-Pilot Test							
1979 Total	103,442	13,500	13%	180,000	0.08	0.57	0.13
Mo. Avg.	8,620	1,125		15,000			
1980 Total	84,178	11,402	14%	140,000	0.08	0.61	0.14
Mo. Avg.	7,065	950		11,667			
B. Post-Pilot Test							
1981							
1st Quarter Total	13,767	2,037	15%	47,000			0.15
Mo. Avg.	4,589	679		15,500			
2nd Quarter Total	21,024	5,855	28%	48,000			0.28
Mo. Avg.	7,008	1,952		16,000			
3rd Quarter Total	33,708	8,469	25%	47,000			0.25
Mo. Avg.	11,236	2,823		15,800			
4th Quarter Total	20,692	7,379	35%	37,000			0.35
Mo. Avg.	6,931	2,460		12,400			
1981 Total	89,291	23,740	27%	179,000	0.13	0.50	0.27
Mo. Avg.	7,441	1,978		14,917			
1982							
1st Quarter Total	11,716	5,622	48%	28,600			0.48
Mo. Avg.	3,905	1,874		9,500			
2nd Quarter Total	8,097	3,664	45%	18,400			0.45
Mo. Avg.	2,699	1,221		6,100			
1982 Total (6 mos)	19,813	9,286	47%	47,000	0.20	0.43	0.47
Mo. Avg.	3,302	1,554		7,833			

III. ANALYSIS OF OIL PRODUCTION RESPONSE IN SECOND RING PRODUCTION WELLS (PATTERN 590-21)

An additional 57,000 barrels of oil were recovered from the second ring wells during the 18 months of the steam with additives tests.

- Incremental oil production in 1981, over a normal decline, was 36,000 barrels.

- Incremental oil production for the first six months of 1982 averaged nearly 3,500 per month or 21,000 barrels.

The analysis of oil production, tracer tests, and casing gas in the second ring of wells surrounding Pattern 590-21 shows a significant and sustained response to the injection of steam and additives in eight of the 12 wells as identified on Figure 2-11.

Notable increases in oil production incurred at these eight wells while the four wells not in the path of steam with additives continued to experience a normal decline, Figure 2-12. The wells have been steam soaked since the early 1970's, had a normal decline for several years, and analysis of steam soak practices shows no unusual change from prior years.

The changes in oil production for the second ring wells are summarized below:

- Oil production that averaged 90 barrels per day (B/D) in 1979 and 88 B/D in 1980 increased to 162 B/D in 1981 and 160 B/D per day for the first six months of 1982.

- Oil production for the 8 wells in the path of steam with additives increased from a base of 58 and 61 B/D (1979 and 1980) to 147 B/D in 1981 and 1982.

Figure 2-11

SECOND LINE RINGS WITH RESPONSE TO TESTS

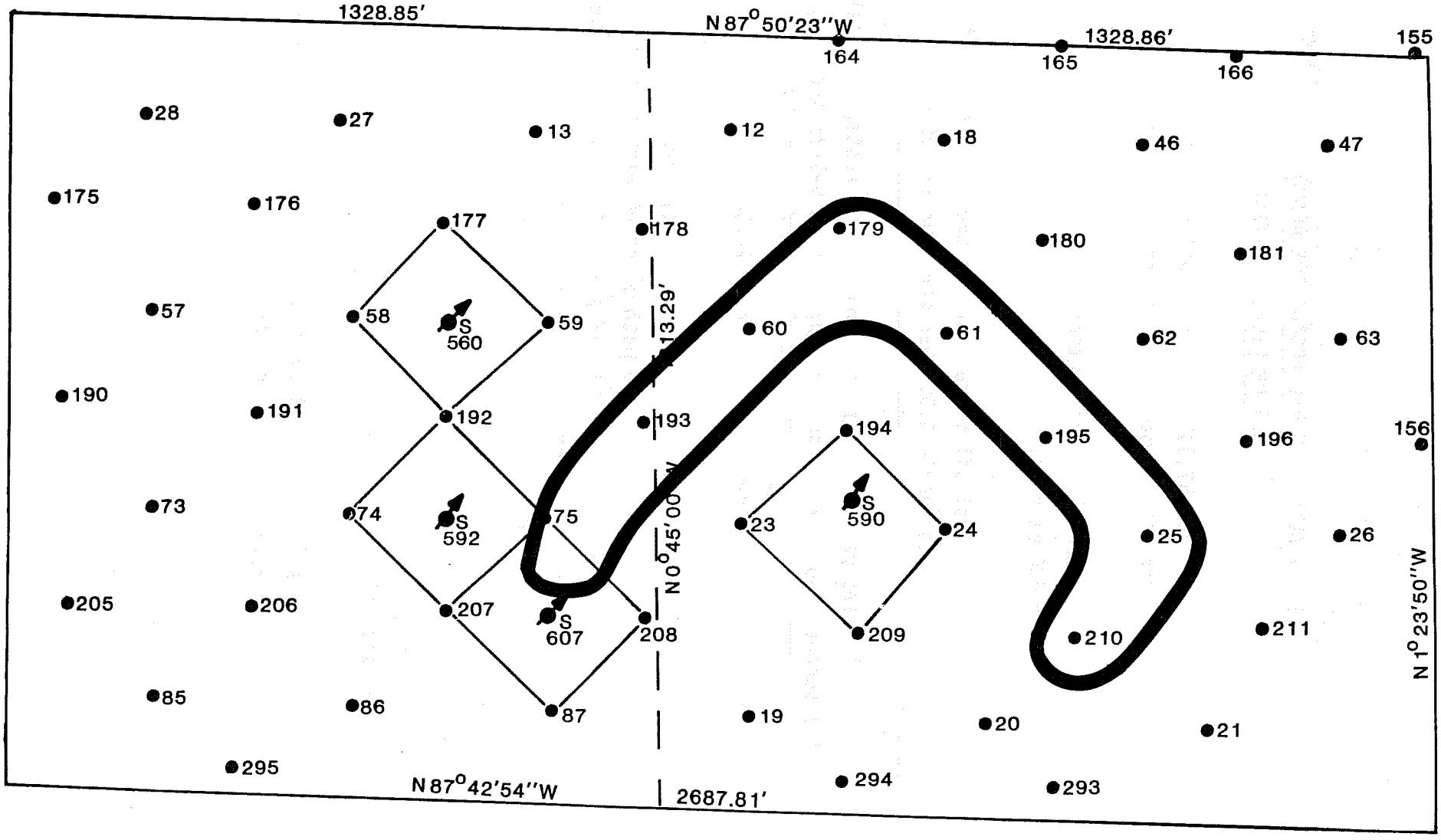
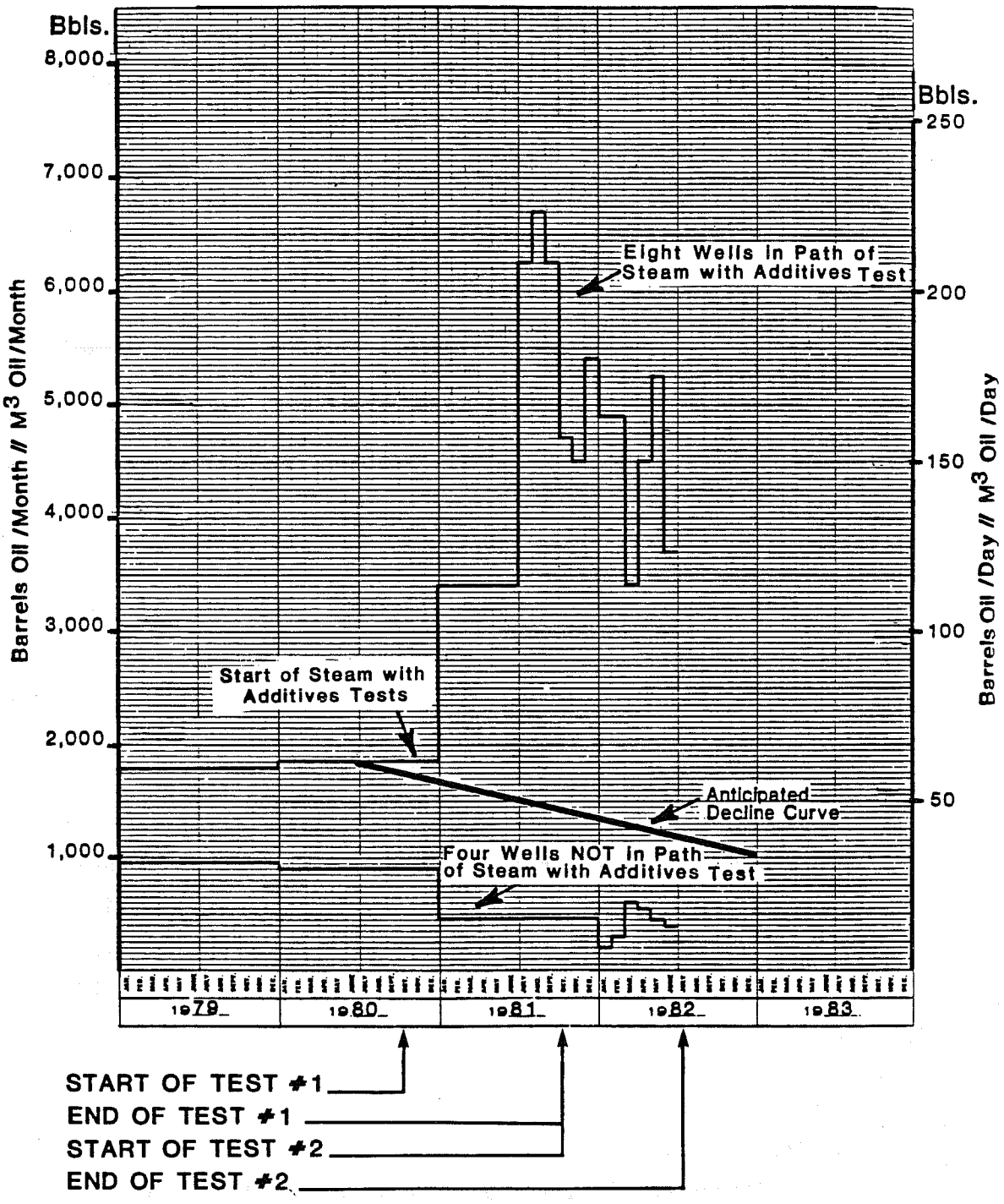


Figure 2-12

OIL PRODUCTION -2nd RING WELLS

(PATTERN 590-21)



- Oil production for the 4 wells not in the path of steam and additives continued to decline--32 B/D in 1979, 27 B/D in 1980, 15 B/D in 1981 and 13 B/D in 1982.

The detailed production well-by-well data is shown on Table 2-7 and summarized below:

Oil Production (B/D)

12 Second Ring Producers -- Pattern 590-21

	8 Wells in Path of Steam w/Additives		4 Wells Not in Path of Steam w/Additives		All 12 Wells	
	Total	Per Well	Total	Per Well	Total	Per Well
1979	58	7	32	8	90	8
1980*	61	8	27	7	87	7
1981	147	18	15	4	162	14
1982 (Jan-June)	147	18	13	3	160	14

*Chemical and air injection started November, 1980

The oil-steam ratio, the most important measure of economic performance, also improved substantially for the second ring wells. The ratio increased to 0.56 in 1981 from a base of 0.19 and 0.25 in 1979 and 1980 (steam soak plus allocation of continuous steam injection in Patterns 592, 560 and 607 to the second ring wells), as shown on Figure 2-13. A major difference is noted among the wells affected and not affected:

- The oil-steam ratio for the 8 wells in the path of steam with additives was 0.71 in 1981 and 1.16 for the first six months of 1982, up from 0.27 in 1980 (steam soak plus drive).

TABLE 2-7
SUMMARY OF OIL PRODUCTION -- SECOND RING WELLS
(AROUND PATTERN 590-21)

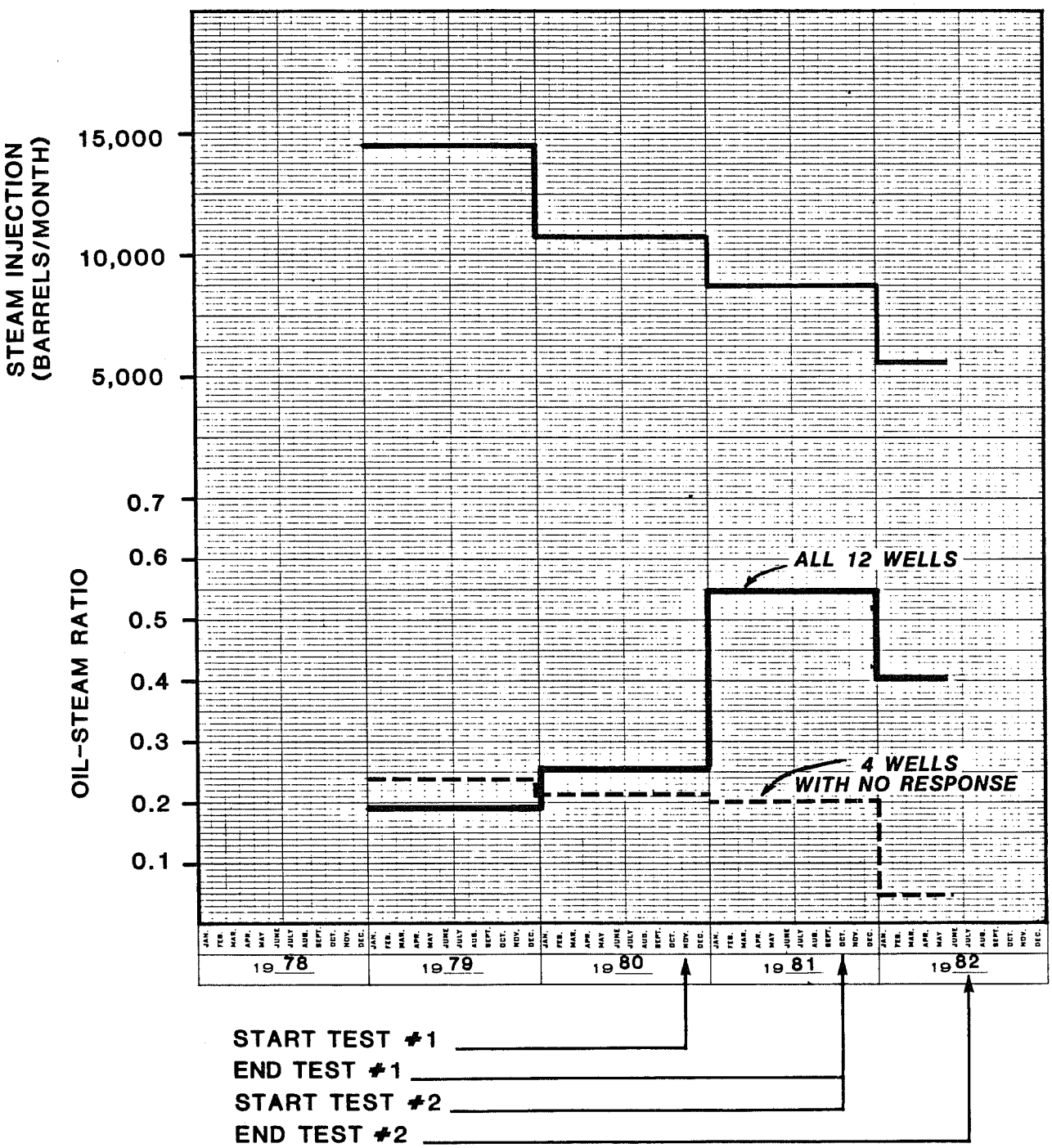
Well	19	20	25*	60*	61*	75*	179*	193*	195*	208	210*	294	Summary 8 Wells w/Response	Summary 4 Wells wo/Response	Summary TOTAL
1979**	2.0	2.8	2.7	2.1	3.2	1.7	5.7	1.7	2.0	4.0	2.2	2.9	21.3	11.8	33.1
1980**	2.0	2.0	1.3	0.6	3.1	2.2	3.4	10.0	0.7	3.7	0.9	2.2	22.2	9.9	32.1
Avg 79-80	2.0	2.4	2.0	1.4	3.2	2.0	4.6	5.8	1.3		1.5		21.8	10.8	32.6
Cum '80 (MB)	67.8	90.5	70.7	55.1	62.9	69.9	52.0	63.3	47.2	47.2	95.4	51.9			
1981**	1.3	1.7	5.4	3.0	4.4	13.7	3.9	10.9	5.7	1.8	6.6	0.8	53.6	5.6	59.2
													31.8	5.2	26.6
1982 1***	32	11	591	603	605	720	355	375	1,291	125	345	11	4,885	179	5,064
2***	18	2	727	482	756	764	327	984	418	226	445	44	4,903	290	5,193
3***	52	222	1,672	594	25	215	121	493	137	122	162	209	3,419	605	4,024
4***	34	319	1,324	241	266	583	687	882	239	123	278	54	4,500	530	5,030
5***	38	180	1,518	685	97	751	398	1,168	320	187	325	59	5,260	464	5,724
6***	77	77	626	469	210	663	-	1,030	339	180	309	51	3,646	385	4,031
													26,613	2,453	29,066

* Wells with response to steam-with-additives.
** Yearly data, Mbbls.
*** Monthly data, barrels.

Figure 2-13

OIL-STEAM RATIO AND STEAM INJECTION - 2nd Ring Wells

(PATTERN 590-21)



- The oil-steam ratio for the four wells not in the path of steam with additives continued to decline to 0.19 in 1981 and 0.05 in the first 6 months of 1982 from a pre-test base of 0.23 in 1980 (steam soak plus drive).

The data on oil production, steam injection and the oil-steam ratio is shown on Table 2-8. The data includes allocation of continuous steam injection, in 1979 and early 1980, to Patterns 592, 560, and 607.

The oil cut, the third measure of performance, improved as well:

- The oil cut for the 8 wells in the path of steam with additives increased from a pre-test base of 15% in 1980 to 30% in 1981 and to 33% in 1982.

- The oil cut for the 4 wells not in the path of steam with additives declined from a pre-test base of 37% in 1980 to 24% in 1981 and to 15% in 1982.

The data on the oil cut for the second pattern wells is provided below:

OIL CUT

12 SECOND-RING PRODUCERS -- PATTERN 590-21

	8 Wells in Path of Steam w/additives	4 Wells Not in Path of Steam w/additives
1979	9%	43%
1980	15%	37%
1981	30%	24%
1982 (Jan.-June)	33%	15%

The key summary data on the performance of the second ring wells to Pattern 590-21 are provided on Table 2-9.

Table 2-10 summarizes the comparison between the performance of Pattern 590-21, and the second ring patterns, expressed as those affected and those not affected by the test.

TABLE 2-8

SECOND-LINE RESULTS--SUMMARY

Time Period	Wells	Oil Production (MB/yr)			Steam Injection* (MB/yr)			Oil-Steam Ratio		
		12	8 w/Response	4 w/o Response	12	8 w/Response	4 w/o Response	12	8 w/Response	4 w/o Response
1. Historical	1978	-	-	-	-	-	-	-	-	-
	1979	33	22	12	174	128	51	0.19	0.17	0.23
	1980	32	22	10	128	83	45	0.25	0.27	0.23
2. After Steam w/Additives	1981	59	54	6	106	76	30	0.56	0.71	0.19
	1982 (Jan-June)	29	27	2	68	23	45	0.43	1.16	0.05

TABLE 2-9

PERFORMANCE OF SECOND RING WELLS -- Pattern 590-21

	8 Wells Affected by Steam w/Additives					4 Wells Not Affected By Steam w/Additives				
	Gross Fluid (Bbls)	Net Oil (Bbls)	Oil Cut, % v/v	Steam (Bbls)	Oil-Steam Ratio v/v	Gross Fluid (Bbls)	Net Oil (Bbls)	Oil Cut, % v/v	Steam (Bbls)	Oil-Steam Ratio v/v
A. Pre-Pilot Test										
1979 Total	228,986	21,510	9.4%	123,000	0.17	27,537	11,709	42.5%	51,000	0.23
Mo. Avg.	19,082	1,792				2,295	976			
1980 Total	145,645	22,215	15.3%	83,000	0.27	27,863	10,258	36.8%	45,000	0.23
Mo. Avg.	12,137	1,851				2,322	855			
B. Post-Pilot Test										
1981										
1st Quarter Total	38,205	9,858				5,889	1,817			
Mo. Avg.	12,735	3,286				1,963	606			
2nd Quarter Total	39,852	9,968				4,686	1,219			
Mo. Avg.	13,184	3,323				1,562	406			
3rd Quarter Total	64,926	19,455				4,632	792			
Mo. Avg.	21,642	6,485				1,544	264			
4th Quarter Total	42,630	14,586				6,546	627			
Mo. Avg.	14,210	4,862				2,182	209			
1981 Total	179,552	53,630	29.7%	76,000	0.71	23,170	5,567	24.0%	30,000	0.19
Mo. Avg.	14,963	4,469				1,930	464			
1982										
1st Quarter Total	33,249	13,206				8,154	1,074			
Mo. Avg.	11,083	4,402				2,718	358			
2nd Quarter Total	46,797	13,407				8,517	1,379			
Mo. Avg.	15,599	4,469				2,839	460			
1982 Total (6 mos)	80,046	26,613	33.2%	23,000	1.16	16,671	2,453	14.7%	45,000	0.05
Mo. Avg.	13,341	4,436				2,778	409			

TABLE 2-9 (Continued)

PERFORMANCE OF SECOND RING WELLS -- Pattern 590-21

	Gross Fluid (Bbls)	Net Oil (Bbls)	Oil Cut, % v/v	Steam (Bbls)	Oil-Steam Ratio v/v	Fluid Balance (Gross fluid/ Steam Inj.)
A. Pre-Pilot Test						
1979 Total	256,523	33,259	12.9%	174,000	0.19	1.47
Mo. Avg.	21,378	2,768				
1980 Total	173,507	32,473	18.7%	128,000	0.25	1.36
Mo. Avg.	14,459	2,706				
B. Post-Pilot Test						
1981						
1st Quarter Total	44,091	11,676	26.5%			
Mo. Avg.	14,697	3,892				
2nd Quarter Total	44,238	11,187	25.3%			
Mo. Avg.	14,746	3,729				
3rd Quarter Total	72,477	21,124	29.1%			
Mo. Avg.	24,149	7,641				
4th Quarter Total	49,178	15,213	30.9%			
Mo. Avg.	16,398	5,071				
1981 Total	209,982	59,200	28.2%	106,000	0.56	1.98
Mo. Avg.	17,498	4,933				
1982						
1st Quarter Total	42,135	14,284	33.9%			
Mo. Avg.	14,045	4,761				
2nd Quarter Total	55,312	14,787	26.7%			
Mo. Avg.	18,437	4,929				
1982 Total (6 mos)	97,447	29,071	29.8%	68,000	0.43	1.43
Mo. Avg.	16,241	4,845				

TABLE 2-10

COMPARATIVE PERFORMANCE OF PATTERN AND SECOND RING WELLS AFFECTED AND NOT AFFECTED BY INJECTION OF STEAM-WITH-ADDITIVES

	Pattern 590-21	Affected 2nd Ring	Total Affected	Not Affected 2nd Ring	Total
A. No. Patterns	1	5	6	3	9
Acres	1.5	7.5	9	4.5	13.5
Wells	4	8	12	4	16
B. Prior Production					
Original Oil In-Place (MBbls)	660	3,300	3,960	1,980	5,940
Recovery thru 12/80 (MBbls)	308	516	824	257	1,081
% Recovery, 12/80	47%	16%	21%	13%	18%
C. Oil Recovery (MBbls/yr.)					
1980 (Base Year)	11.4	22.2	33.6	10.3	43.9
1981	23.7	53.6	77.3	5.6	82.9
1982 - 6 mos.	9.3	26.6	35.9	2.5	38.4
- (annualized)	18.6	53.2	71.8	5.0	76.8
D. Oil-Steam Ratio (v/v)					
1980 (Base Year)	0.08	0.27	0.15	0.23	0.16
1981	0.14	0.71	0.30	0.19	0.29
1982 (6 mos.)	0.20	1.16	0.51	0.05	0.33
E. Oil-Cut (%)					
1980 (Base Year)	13	15	15	37	17
1981	27	30	29	24	28
1982 (6 mos.)	47	33	36	15	33
F. Steam Injection (MBbls/yr.)					
1980 (Base Year)	140	80	220	45	265
1981	180	80	260	30	290
1982 (6 mos.)	47	23	70	45	115

IV. ANALYSIS OF OIL PRODUCTION RESPONSE IN THIRD RING PRODUCTION WELLS (PATTERN 590-21)

Analysis of oil production in the third ring of wells surrounding Pattern 590-21 shows improved oil recovery in six of the 16 wells. The six wells, identified by tracer survey, temperature survey, and casing head gas analysis as being in the path of steam from Well 590-12 are identified on Figure 2-14.

- Incremental oil production in 1981, over a normal decline, was 23,000 barrels (Figure 2-15).

- Incremental oil production for the first six months of 1982 averaged 1,200 barrels per month or 7,000 barrels in total.

- During the 18 months of the tests, an incremental 30,000 barrels of oil were recovered from the third ring wells.

In 1979 and 1980, oil production averaged 187 and 191 barrels per day, respectively, for all 16 of the third ring wells. This increased to 214 barrels per day in 1981, and declined to 155 barrels per day for the first six months of 1982. However, a distinct difference is observable between the six wells in the path of steam with additives and the other ten wells in the third ring:

- Oil production for the six wells in the path of steam with additives increased from an average of 62 B/D in 1979 and 61 B/D in 1980 to 110 B/D in 1981 and 82 B/D in 1982.

- Oil production for the 10 wells <u>not</u> in the path of steam with additives continued to decline--from 125 B/D in 1979 and 130 B/D in 1980, to 104 B/D in 1981 and 73 B/D in 1982.

Figure 2-14

STEAM DRIVE PATTERN 590-21 "N" ZONE

THIRD RING WELLS RESPONDING TO STEAM WITH CHEMICALS

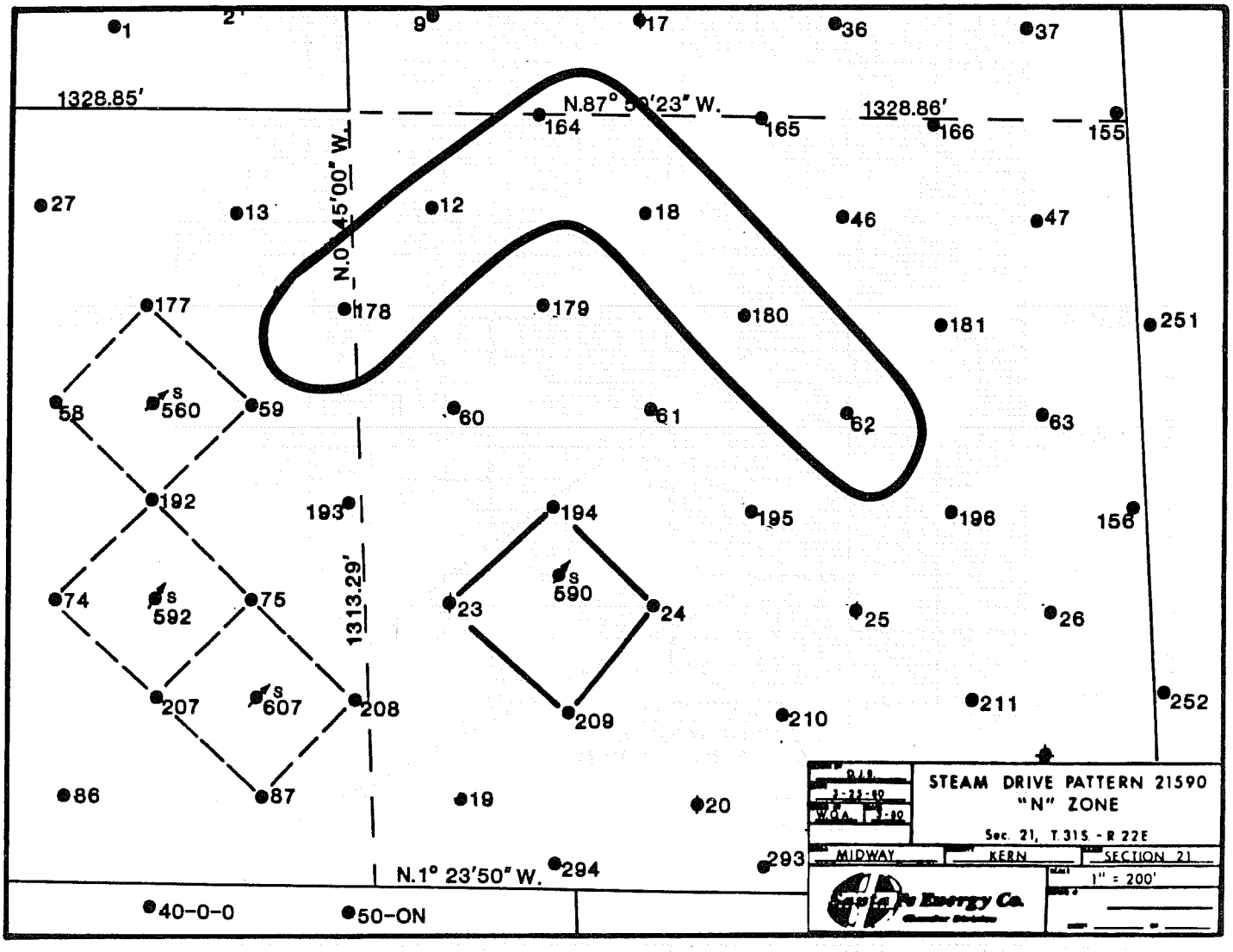
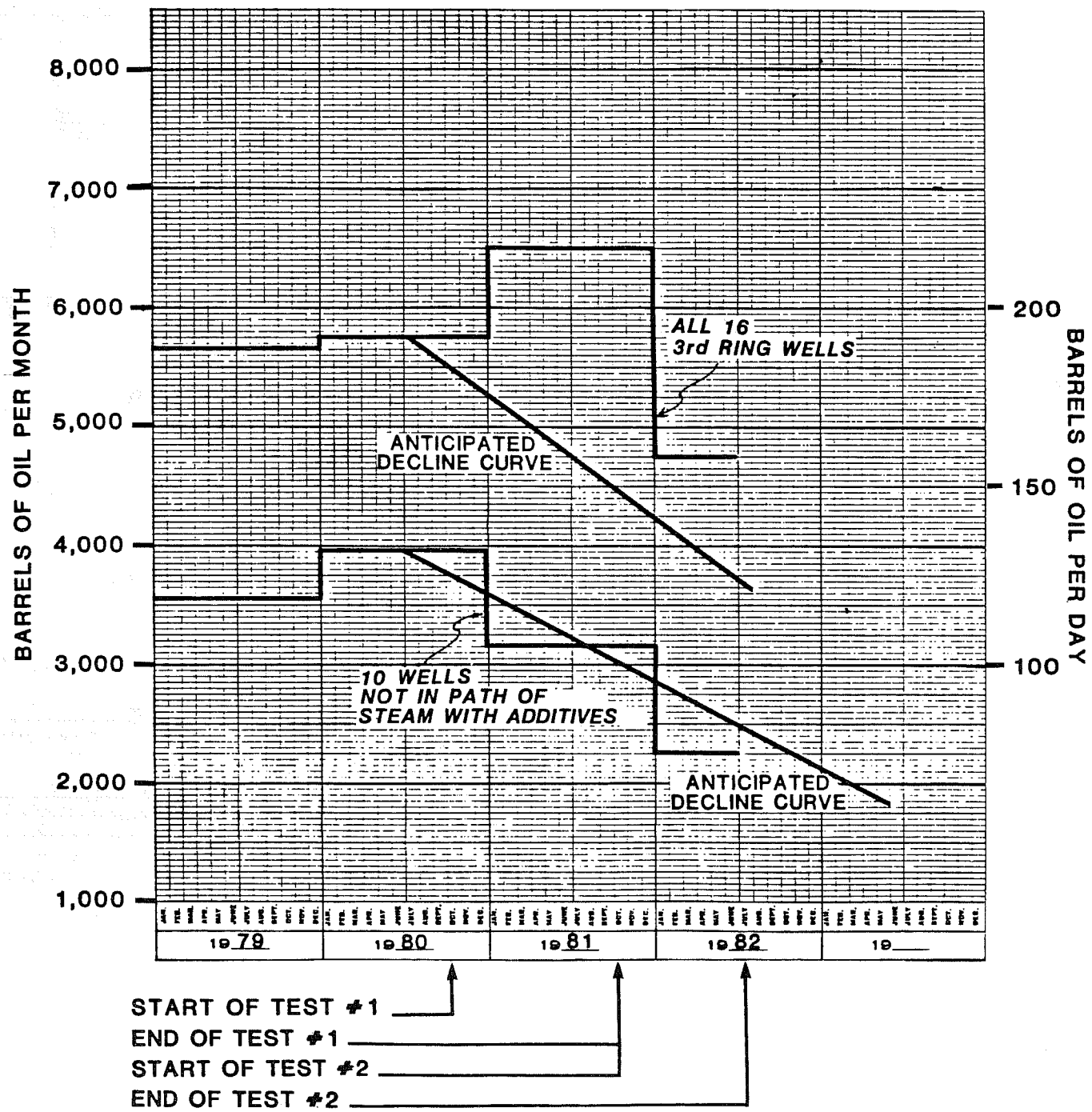


Figure 2-15

OIL PRODUCTION - 3rd RING WELLS

(PATTERN 590-21)



The detailed well-by-well data is shown on Table 2-11 and is summarized below:

Oil Production (B/D) of Third Ring Producers to Pattern 590-21

	6 Wells in Path of Steam w/Additives		10 Wells Not in Path of Steam w/Additives		All 16 Wells	
	Total	Per Well	Total	Per Well	Total	Per Well
1979	62	10	125	12	187	12
1980*	61	10	130	13	191	12
1981	110	18	104	10	214	13
1982 (Jan.-June)	82	14	73	7	155	10

* Chemical injection started November, 1980

With the termination of continuous steam injection in Patterns 592, 560, and 607, the third ring wells received less steam in 1981 (110,000 barrels) than in 1979 and 1980 (340,000 and 170,000 barrels, respectively). Counting all of the injected steam, the oil-steam ratio increased to 0.60 in 1981 from bases of 0.18 (1979) and 0.38 (1980). The major difference in the 1981 performance is due to the six wells in the path of steam from pattern 590-12:

- The oil-steam ratio for the six wells in the path of steam improved from 0.74 in 1980 to 0.81 in 1981 and has remained high (at 0.59 for the first six months of 1982).

- The oil-steam ratio for the 10 wells not in the path of steam also improved from 0.31 in 1980 to 0.61 in 1981; however, in the first six months of 1982 the oil-steam ratio for these 10 wells declined to 0.26.

TABLE 2-11

SUMMARY OF OIL PRODUCTION -- THIRD RING WELLS

(AROUND PATTERN 590-21)

Well	12*	18*	21	26	59	62*	74	87	164*	178	180*	192	196*	207	216	293	Summary 6 Wells w/Resp.	Summary 10 Wells w/o Resp.	Summary TOTAL
1979**	5.7	4.1	3.2	2.5	2.5	1.9	3.5	2.3	6.3	9.7	3.2	3.2	1.6	5.0	3.1	3.4	22.8	45.4	68.2
1980**	6.6	2.6	2.9	2.1	7.2	1.6	10.2	3.2	7.4	5.9	2.5	3.5	1.6	2.8	2.8	1.9	22.3	47.5	69.8
Avg. 79-80	6.2	3.4				1.8			6.8		2.8		1.6				22.6	46.4	69.0
Cum'80 (MB)	93.7	95.7	106.6	65.1	63.5	37.5	65.4	53.5	27.5	63.4	42.4	44.5	35.0	50.7	59.4	53.2			
1981**	14.6	6.6	1.5	0.9	5.7	2.6	6.3	4.7	9.2	3.8	3.6	1.0	3.7	3.2	2.6	1.1	40.3	37.8	78.1
																	17.7	[8.6]	9.1
1982 1***	512	406	45	34	167	373	197	542	599	660	375	30	1246	137	413	41	3511	2266	5777
2***	305	24	70	14	229	468	175	326	557	599	755	19	641	151	491	97	2750	2171	4921
3***	N.D.	87	106	262	176	525	185	113	462	412	756	21	490	132	490	171	2320	2068	4388
4***	104	81	229	349	123	464	362	36	404	399	796	149	369	227	265	102	2218	2241	4459
5***	54	106	373	299	25	481	135	53	183	526	889	65	95	267	240	93	1808	2076	3884
6***	421	180	154	103	480	592	124	390	219	483	772	231	72	191	257	154	2756	2567	4823
																	14,863	13,389	28,252

* Wells with response to steam with chemicals.

** Yearly data, M Bbls.

*** Monthly data, barrels.

The data on oil production, steam injection and the oil-steam ratio for the third ring wells are shown on Table 2-12. The data includes allocation of continuous steam injection (in 1979 and early 1980) from Patterns 592, 560, and 607. Figure 2-16 shows the steam injection and the oil-steam ratio for the third ring wells.

The key summary data on the performance of the third ring wells (to Pattern 590-21) are provided on Table 2-13.

TABLE 2-12

THIRD-LINE FLUID BALANCE, PATTERN 590-12

	Oil Production (MB/yr)			Steam Injection (MB/yr)			Oil-Steam Ratio		
Wells:	All 16	6 w/ Response	10 w/o Response	All 16	6 w/ Response	10 w/o Response	All 16	6 w/ Response	10 w/o Response
Time Period									
Historical									
1978	-	-	-	360	40	320	-	-	-
1979	61	23	38	342	43	299	0.18	0.53	0.13
1980	65	22	43	170	30	139	0.38	0.74	0.31
After Steam w/Additives									
1981	71	40	31	108	50	60	0.66	0.81	0.51
1982 (6 Mos.)	28	15	13	94	25	52	0.30	0.59	0.26

Figure 2-16

OIL-STEAM RATIO
STEAM INJECTION - 3rd RING WELLS
(PATTERN 590-12)

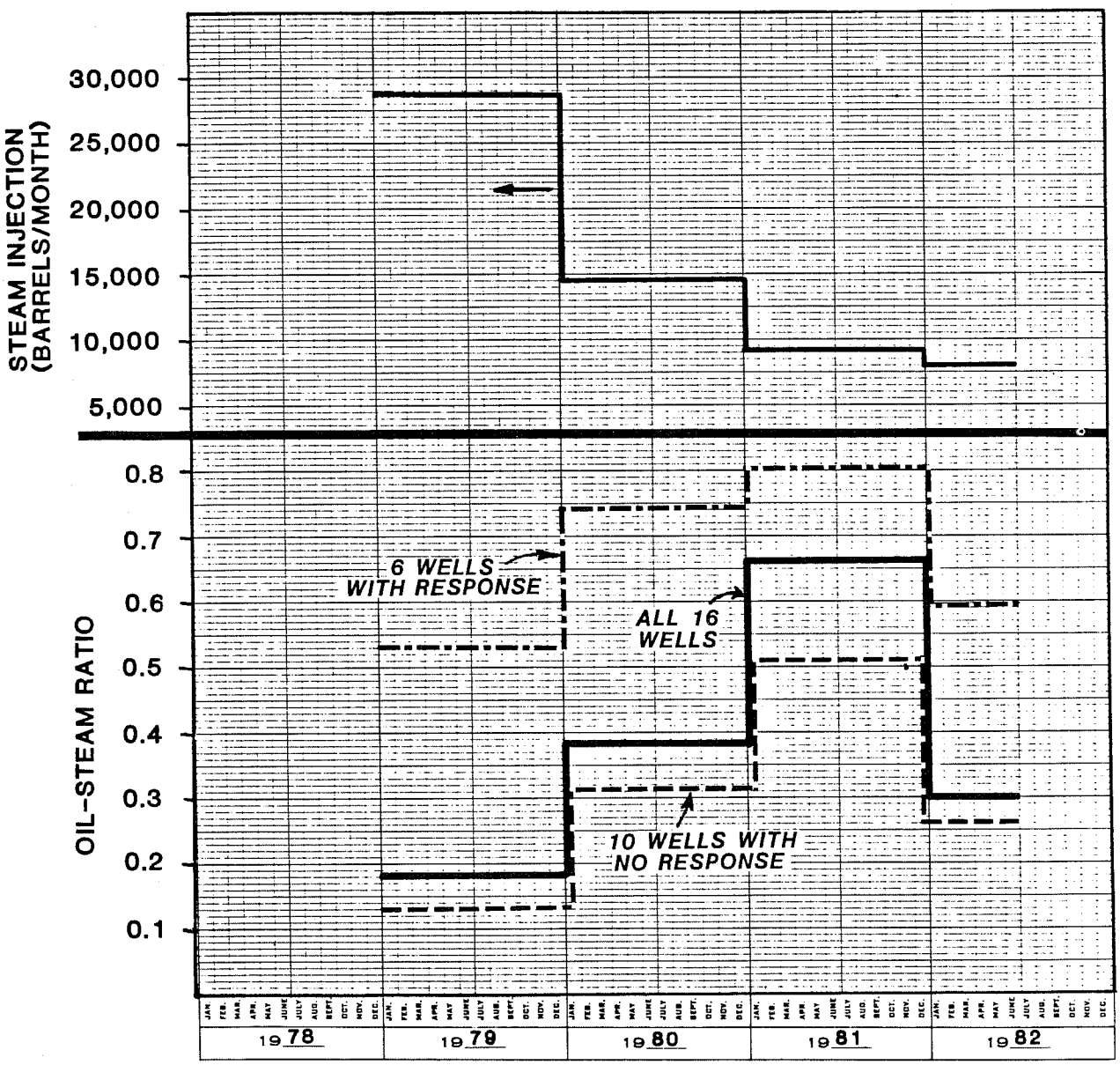


TABLE 2-13

PERFORMANCE OF THIRD RING WELLS -- Pattern 590-21

	6 Wells Affected by Steam w/Additives					10 Wells Not Affected By Steam w/Additives				
	Gross Fluid (Bbls)	Net Oil (Bbls)	Oil Cut, % v/v	Steam (Bbls)	Oil-Steam Ratio v/v	Gross Fluid (Bbls)	Net Oil (Bbls)	Oil Cut, % v/v	Steam (Bbls)	Oil-Steam Ratio v/v
A. Pre-Pilot Test										
1979 Total	43,671	22,719	52.0%	43,000	0.53	93,769	38,252	40.8%	299,000	0.13
Mo. Avg.	3,639	1,893				7,814	3,188			
1980 Total	42,904	22,314	52.0%	30,000	0.74	83,071	42,558	51.2%	139,000	0.31
Mo. Avg.	3,575	1,860				6,923	3,546			
B. Post-Pilot Test										
1981										
1st Quarter Total	21,603	5,940				14,846	4,461			
Mo. Avg.	7,201	980				4,949	1,487			
2nd Quarter Total	32,844	13,714				22,616	8,895			
Mo. Avg.										
3rd Quarter Total	25,820	9,308				23,328	9,903			
Mo. Avg.						7,443	3,004			
4th Quarter Total	24,246	11,381				24,843	7,531			
Mo. Avg.	8,082	3,794				8,281	2,510			
1981 Total	104,513	40,343	38.6%	50,000	0.81	86,633	30,790	35.5%	60,000	0.51
Mo. Avg.						7,219	2,566			
1982										
1st Quarter Total	22,714	8,581				25,267	6,505			
Mo. Avg.	7,571	2,860				8,422	2,168			
2nd Quarter Total	26,546	6.282				20,975	6,884			
Mo. Avg.	8,849	2,094				6,992	2,295			
1982 Total (6 mos)	49,260	14,863	30.2%	25,000	0.59	46,242	13,389	29.0%	52,000	0.26
Mo. Avg.	8,210	2,477				7,707	2,232			

TABLE 2-13 (Continued)

PERFORMANCE OF THIRD RING WELLS - Pattern 590-21

	Gross Fluid (Bbls)	Net Oil (Bbls)	Oil Cut, % v/v	Steam (Bbls)	Oil-Steam Ratio v/v	Fluid Balance (Gross Fluid/ Steam Inj.)
A. Pre-Pilot Test						
1979 Total	137,440	60,971	44.4%	342,000	0.18	0.40
Mo. Avg.	11,453	5,081				
1980 Total	125,975	64,872	51.5%	170,000	0.38	0.74
Mo. Avg.	10,498	5,406				
B. Post-Pilot Test						
1981						
1st Quarter Total	36,449	10,401				
Mo. Avg.	12,150	3,467				
2nd Quarter Total	56,460	22,609				
Mo. Avg.	18,820	7,536				
3rd Quarter Total	49,148	19,211				
Mo. Avg.	16,383	6,404				
4th Quarter Total	49,089	18,912				
Mo. Avg.	16,363	6,304				
1981 Total	191,146	71,133	37.2%	108,000	0.66	1.77
Mo. Avg.	15,929	5,928				
1982						
1st Quarter Total	47,981	15,088				
Mo. Avg.	15,994	5,029				
2nd Quarter Total	47,521	13,166				
Mo. Avg.	15,840	4,387				
1982 Total (6 mos)	95,502	28,254	29.6%	94,000	0.30	1.02
Mo. Avg.	15,917	4,709				