BERC/TPR-77/7

NORTH STANLEY POLYMER DEMONSTRATION PROJECT, SECOND ANNUAL REPORT

By

Kewanee Oil Company
Prepared for DOE Under Contract No. EY-76-C-02-0029

Date Published—October 1977

Bartlesville Energy Research Center
Department of Energy
Bartlesville, Oklahoma

TECHNICAL INFORMATION CENTER
UNITED STATES DEPARTMENT OF ENERGY

NOTICE

Available from the National Technical Information Service, U. S. Department of Commerce, Springfield, Virginia 22161.

Price: Paper Copy $7.25
Microfiche $3.00

Printed in the United States of America
USDOE Technical Information Center, Oak Ridge, Tennessee

BERC/TPR-77/7
Distribution Category UC-92a

NORTH STANLEY POLYMER DEMONSTRATION PROJECT, SECOND ANNUAL REPORT

KEWANEE OIL COMPANY

Jarl P. Johnson
Manager of Engineering

J. W. Cunningham
Assistant Manager of Engineering

B. M. DuBois
District Engineer

Fred W. Burtch
Technical Project Officer
Bartlesville Energy Research Center
Department of Energy
Bartlesville, Oklahoma

Prepared for the Department
of Energy under Contract No. EY-76-C-02-0029

Date Submitted—July 1977
Date Published—October 1977

UNITED STATES DEPARTMENT OF ENERGY
TECHNICAL INFORMATION CENTER

TABLE OF CONTENTS

SUMMARY

The North Stanley Polymer Demonstration Project is a cooperative test of the economics of polymer enhanced waterflooding. It is a field scale test involving 1,010 productive acres containing 72 million barrels of pore volume, 19 injection wells, and 28 producers. The project is conducted under Contract Number EY-76-C-02-0029.*000 between Kewanee Oil Company and the Energy Research and Development Administration.

The objectives, history, and activities of the first contract year are discussed in detail in the first annual report available from ERDA and published in October 1976 as BERC/TPR-76/3. This report covers the activities of the second contract year which ended June 25, 1977.

The primary activity during the second year of the project was successful injection of the polymer slug. Polymer injection was completed June 22, 1977, after injecting 1,194,770 pounds of Dow Pusher 700 and 11,962,918 barrels of water over a period of 372 days. The average polymer concentration during the period was 285 parts per million.

In order to accelerate the change in injection profiles and to decrease per well injection rates below 3,000 BPD, nine of the injection wells were given Channelblock* treatments. Seven of the nine treatments were successful on the initial attempt. Retreatment of one well was required after one month. The retreatment and the initial treatment on a second well broke down after six months. The two wells were subsequently retreated successfully. One well, Pappin 12, did not respond to the Channelblock treatment. It was the closest well to the injection plant, and the pressure was too high for the soft gel

*Trademark of the Dow Chemical Company

to hold. The rate on Pappin 12 was then restricted by use of a flow regulator coil. The polymer at 250 ppm concentration experienced a 12% shear degradation passing through the regulator coil.

Movement of the slug through the reservoir was monitored by analysis of produced water samples. The producing wells were sampled every two weeks from February 1976 through June 1976 and once a month thereafter. The water samples were analyzed for changes in salinity and the presence of polymer. A study is under way to determine the change in sweep efficiency resulting from the polymer injection and Channelblock treatments by balancing the salinity changes and polymer breakthrough with injection volumes.

The mixing and injection equipment functioned extremely well and was operated by the lease pumper with a minimum of outside supervision. The primary producing problem experienced was a change in the producing well fluid levels resulting from the changes in injection distribution. Since most of the wells are produced through downhole centrifugal pumps, which are designed for a specific fluid level, it was necessary to either change out the pump or lower the present pump which resulted in less efficiency. Although it is not possible to predict the magnitude and location of fluid level (i.e. reservoir pressure) changes in advance, anyone planning a polymer injection project should include adequate funds to enable corrections to be made in the pumping equipment where necessary.

The oil production started responding in September 1976 by increasing 15 BPD to 581 BPD. It increased to 586 BPD in October, 590 BPD in November, and 592 BPD in December. In January production jumped to 660 BPD, an increase of 68 BPD. It fell back to 641 in February but slowly increased to 658 BPD by May. June's production fell back to 645 BPD, partially as a result of lower injection rates experienced when polymer injection was terminated. The response to date has exceeded the predictions and is quite encouraging. Production must continue to increase if the overall project goals are to be met. Until more history is available, projecting the response is uncertain, and economics are hazy.

During the final project year, a detailed study will be made to identify what changes have occurred in the fluid movement in the reservoir and how the movement will affect sweep efficiency and ultimate recovery. As a result of that study, a firm response projection will be made, and project economics will be calculated. In the immediate future, the feasibility of a micellar injection project will be determined. If the micellar project is not feasible, the fresh water injection will be terminated and replaced with produced water injection.

DISCUSSION

Polymer Injection

Polymer injection was initiated on June 16, 1976. The initial concentration was 200 ppm while the injection system was being checked out and calibrated. On June 21 the concentration was increased to the design rate of 250 ppm. Table 1 lists the actual injection schedule utilized. Although minor variations were required to achieve the total design weight of polymer in each phase, the basic schedule shown on the Milestone Chart in the first annual report was followed. Polymer injection was completed on June 22, 1977, only seven days behind the scheduled completion date.

For the total period, 1,194,770 pounds of Dow Pusher 700 polymer were injected in solution with 11,962,918 barrels of fresh water treated with 14,250 pounds of Virchem D-OX (oxygen scavenger). The polymer injection period lasted 372 days. The average polymer concentration was 285 ppm while the average fresh water injection rate was 32,158 bbls/day.

Injection Rate-Pressure Performance

Figures 1 and 1A show the injection rate and plant pressure during the polymer injection period. During the fresh water preflush period from February to June, the rates and pressures fluctuated as the system was debugged. On June 15, when polymer injection started, the pressure dropped from 270 psi to 190 psi at a rate of 35,000 BPD. The subsequent drop to 150 psi was caused by Hiram 17 WI breaking down and accepting too much water. A Channelblock treatment on Hiram 17 WI was initiated immediately.

The steady increase in plant pressure from July 5 to August 5 was a result of the Channelblock treatments shown in Table 2, Chronology of Events. At that point, the pressure increased to 315 psi which caused Hiram 17 WI to break down again. The second Channelblock job on Hiram 17 WI started on August 10 and was completed on August 23. The polymer concentration was increased to 600 ppm on August 5 and then was increased to 625 ppm on August 19 to make up for a previous period of underinjection. The plant pressure slowly increased while the injection rate remained relatively constant at 32,500 BWPD. On October 21 Big Eagle 11 WI was reactivated. A Channelblock treatment was immediately applied to prevent communication with Big Eagle 3 from recurring. On November 9 the polymer concentration was dropped back to 600 ppm. The Pappin 12 WI injection rate became excessive in early November. An attempted Channelblock treatment was unsuccessful; therefore a flow regulator coil was installed to limit the injection rate at Pappin 12 WI to 2,400 BPD.

The polymer concentration was reduced to 250 ppm on November 18, but was increased to 290 ppm on December 1. The injection pressure climbed to 370 psi by the end of December as a result of the Channelblock work, the flow regulator coil, and the cumulative effect of polymer injection. On January 3, 1977, the polymer was cut back to 250 ppm, and on January 11 it was reduced to 100 ppm. In spite of the lower polymer concentration, the plant pressure stayed between 360-400 psi. In mid January Hiram 17 WI and Gale 14 WI began accepting nearly 5,000 BWPD each as a result of the high injection pressure. The two wells were re-treated, and a decision was made to limit the injection pressure to 350 psi. The injection rate stabilized at 31,000 to 32,000 BWPD from that point to the end of polymer injection. Polymer injection was terminated on June 22, 1977. The plant pressure immediately jumped to 385 psi, and the injection rate fell to 29,000 BPD as a result of losing the friction reducing property of the polymer. On June 25, throttling valves were installed on wells Hiram 17 WI, Gale 14 WI, Gale 11 WI, Art 8 WI, and Pappin 12 WI to limit the injection in those wells. As a result the plant pressure jumped above 450 psi before appearing to stabilize at approximately 430 psi.

Prior to the injection of polymer, the reservoir was accepting approximately 35,000 BPD at a pressure of 300 psi. The cumulative effect of the polymer injection and Channelblock work was to decrease the injection rate 5,000 BPD to 30,000 BWPD and increase the injection pressure 130 psi to 430 psi.

Injection Well Performance

The effect of the Channelblock work on the system injection pressure and rate was discussed in the previous section. Figure 2 gives the location and results of the work by well. Table 3 shows the details of the treatments on each well. The volume of treatment for Hiram 17 WI includes both the first and second stages. The treatments were designed by Dow Chemical Company to yield a soft gel that would penetrate deep into the reservoir rather than a firmer gel that would not penetrate as deeply. In retrospect it is probable that the treatments on Hiram 17 should have ended with a firmer gel in the vicinity of the wellbore. However, it would have been necessary to have added salts to the mixing water to achieve a harder gel. The equipment in use at that time precluded this option.

The most successful job was on Hiram 10 WI where the injection rate dropped from 4,936 BWPD @ 110 psi to 2,010 BWPD @ 192 psi following the treatment. The job was long lived in that the rate dropped to 1,149 BWPD @ 310 psi by November. The well stayed below 2,000 BWPD throughout the remainder of the polymer injection. Gale 14 WI was the second well that required retreatment. The initial job lowered the injection rate from 4,670 BWPD @ 125 psi to 1,119 BWPD @ 235 psi. However, as the system pressure increased, the injection rate shot back up. By November the well was taking 4,505 BWPD @ 300 psi. It is somewhat unfair to call the treatment a failure as the injection rate was less than before treatment, and the injection pressure had more than doubled. It is more accurate to state that the system pressure had increased beyond the design limits of the treatment. Included in Appendix B are plots of each well's injection rate and pressure during the project.

Using injection profile survey results and a comparison of gamma ray log changes, the wells were grouped by injection pattern types. Details of the method of typing were discussed in the first annual report. Figure 3 shows the location of the pattern types and the wells in each group prior to polymer injection. Figure 4 shows the same information at the end of the 600 ppm polymer slug. It should be noted that during the interim the Channelblock treatments had also been performed. Three wells, Pappin 12 WI, 13 WI, and 14 WI, had changed classification due to having perforations added in the upper section. However, 6 wells had changed category as a result of the polymer and/or the Channelblock treatments. They are starred on Figure 4. Four of these wells--Art 8 WI, Big Eagle 9 WI, Fanny 4 WI, and Brenner 9 WI--changed as the result of polymer alone since they had not been Channelblocked. Hiram 17 WI had been Channelblocked twice, and Gale 14 had been Channelblocked once. These most likely were affected primarily by the Channelblock. Figure 5 shows the injection well grouping during the last month of polymer injection when the concentration was 100 ppm. The only well that changed category was Fanny 4. It had originally been injecting into both top and bottom zones. After the 600 ppm polymer, the injection had moved into the top zone only. At the end of the 100 ppm injection, it was taking water in both zones again. Appendix F shows the injection profiles for the three surveys for each well.

In addition to the injection profile surveys, pressure fall-off tests were run on 12 of the 19 wells before polymer, at the end of 600 ppm polymer, and at the end of 100 ppm polymer injection. Table 4 is a comparison of the pressure fall-off calculations from the tests taken prior to the start of polymer injection with those taken after 600 ppm polymer. The wells that received Channelblock treatments are indicated with an asterisk by the well name. The actual plots of pressure vs $(T+\Delta T)/\Delta T$ are included in Appendix D. The calculations have a rather large degree of uncertainty due to several factors. First, the actual viscosity of the polymer solution in the reservoir is questionable as it can be reudced by shear through perforations and/or dilution by formation salt water. Second, the effective formation thickness can be either the total zone thickness, the length of the actual perforated interval which is taking fluid at the wellbore, or a value somewhere in between. Assuming that it is the same during both tests is questionable. The effective height directly affects the permeability calculation.

The calculations indicate a higher permeability capacity suggesting more extensive parting in the injection wells after polymer injection. Although this appears somewhat surprising at first, it should be remembered that the injection pressure is significantly higher at the injection wells, and the rates are nearly the same with a fluid of higher viscosity. It should be expected the wells would experience more extensive parting under those conditions.

Additional pressure fall-off tests were taken just before the termination of polymer injection. These tests are currently being analyzed and will not be discussed in this report.

Fluid Movement

Movement of the two slugs, fresh water and polymer, was monitored by the use of produced water analyses. Water samples were taken from all producing wells twice monthly from February through June 1976. In July the frequency was reduced to once per month. During the semi-monthly sampling period, a complete water analysis was run on each sample to determine the makeup of the produced water. After reviewing the results, it was determined that chlorides or total dissolved solids and specific gravity were the properties that were most consistent. Consequently, the total analyses were dropped, and only the above properties were routinely determined.

The total dissolved solids content of the produced water sample has been contoured on a map with a computer contouring package. The quality of water at the injection wells was considered to be that of the Ark-Burbank water for the purpose of mapping. Work is under way to balance the fresh water injection volumes with the observed dilution of produced water to arrive at an estimate of the amount of reservoir pore space each injection well is affecting and also to estimate the sweep efficiency. The use of a more sophisticated reservoir model that could describe the displacement and crossflow taking place in this reservoir would be difficult to construct because of the irregular well spacing pattern and fracture systems present, and would be prohibitively expensive. The salinity maps are attached in Appendix E.

In a number of cases, the salinity of the produced water increased somewhat prior to dilution occurring. This is an indication that native formation water was being displaced ahead of the fresh water slug. Utilization of the shape of the individual salinity curves will be used to provide judgment factors in the model work to determine whether the dilution in a specific well appears to be caused by fingering from a thin zone or from a large section of the sand. The salinity history for each producing well is included in Appendix A.

The produced water was also tested for the presence of polymer. Each sample was given a clay flocculation test which simply indicates the presence of polymer but gives no quantitative measurements. If a positive test was indicated, the sample was sent to Dow Chemical for quantitative analysis in their lab. The polymer content is shown on the salinity history graphs for the producing wells in Appendix A.

Table 5 lists the breakthrough time for fresh water and polymer for all produced wells. The cases of severe fresh water breakthrough (Big Eagle 3, Gale 14, and Hiram 15) also had very quick polymer breakthrough. In addition, O'Dell 1 had polymer in the produced water within 31 days. Other wells with good agreement between fresh water and polymer breakthrough times were Art 3, Gale 16, Hiram 14, and Hiram 16. In contrast, Art 5 and 9 have had no measurable polymer while showing dilution at 210 and 144 days respectively. Fanny 6 saw dilution in 112 days but required 303 days before polymer breakthrough.

Figure 6 shows the areas experiencing polymer and/or fresh water breakthrough. It is apparent that the north and south ends of the project have not responded to the fresh water and polymer injection and that response on the west side has been limited. In the north end, the primary problem has been lack of productivity of the producing wells. The five wells outside the responding area produced an average of 312 BPD of fluid compared to average producing rates of 1,000 to 2,000 BPD in the better parts of the field. The transmissibility in this part of the reservoir is limited, which causes fluid movement from injectors to producers to be limited also. Consequently, the majority of the injection in this area has moved along the high permeability section to the south and east where the bulk of the withdrawals are. The southern section is affected by the boundary injection wells into which produced water is injected. The boundary injection was designed to insure that the polymer stayed within the project area. The requirements have been somewhat exceeded, and the lack of response in the Pappin and Skelly Barber wells may have been due to over-injection of produced water in the boundary wells, creating an unfavorable pressure gradient.

Production Response

Figure 9 is the injection-production history for the project. The combination of early Channelblock work and polymer injection started paying off in September 1976. Production increased 15 BPD to 581 BPD for the month. It increased 5 BOPD in October, 4 BOPD in November, and 2 BOPD in December. January saw the largest monthly increase the project has experienced as production jumped 68 BOPD to 660 BOPD. That was the largest single month's production since June 1974. February's production fell back to 641 BOPD, but production increased each month through May when it averaged 658 BOPD.

At the end of June when polymer injection was terminated, the water injection rate dropped 1,200 BPD, the water production dropped 547 BPD, and the oil production dropped 13 BPD to 645 BPD.

It is anticipated that both water injection and production will slowly increase over the next several months allowing a return to the previous producing levels.

Both water injection and water-oil ratio performance should also be discussed in light of the increased oil production. As discussed in the Injection Rate-Pressure Performance Section, the overall injection rate decreased during the period of polymer injection. From past performance, a decrease in total fluid and oil production should have resulted. However, the increase in oil production in September coincides with a sharp decrease in water-oil ratio, and the water-oil ratio trend has continued to drop as oil production increased. The economic success of the project will be determined by how long the reversal in historical trends is sustained in the oil production and water-oil ratio performance.

Figure 7 is a map indicating the response seen at each producing well. Eight wells have seen a sustained increase in oil rate. Nine wells have seen some increase in production which was of short duration. Five of the wells are essentially unchanged, while six have experienced a decline in production. The sustained increase is concentrated in the Gale, Hickman, and O'Dell Leases, along with Fanny 6. These wells are directly affected by injection from the Hiram, Gale, and Pappin injection wells. Due to the high injectivity of these wells, 57% of the total polymer was injected into this group of wells. The area also recovered less secondary oil than the flood as a whole. Both reasons could explain the degree of response seen in the area.

The two wells with the best production response are Fanny 6 and O'Dell 1. The producing history for both wells is shown in Figure 8. Fanny 6 started responding in December when the producing rate increased from 36 to 78 BOPD. In January it tested 117 BOPD and in February it peaked at 127 BOPD. Production dropped back for several months reaching a low of 83 BOPD in May. However, in June the rate jumped back up to 103 BOPD.

O'Dell 1 responded sooner by jumping from 18 BOPD in August to 32 BOPD in September. The increase was not as dramatic as Fanny 6; but as Figure 8 shows, production has clearly stayed above the prepolymer level. In both cases, the water-oil ratio dropped when the oil increased and has stayed relatively constant at a lower level.

Two of the wells with short-lived production kicks were Hiram 16 and Art 9. Both appear to have been the victim of communication with offset injection wells as the water-oil ratios jumped up markedly following the production increase. Decreased production in five wells--Big Eagle 3, Art 5, Fanny 7, Hiram 15, and Pappin 15--can be at least partially explained by lower total fluid withdrawals caused by a decrease in the fluid levels in the wells.

Individual production curves showing oil rate, total water rate, and water-oil ratio performance are included in Appendix C. Four of the nine wells that have shown a short-lived increase in production started responding at the same time that polymer breakthrough occurred. Three of the eight wells with sustained production increases also started responding at the same time polymer breakthrough was observed. Figure 10 shows the salinity and polymer history for O'Dell 1 above the producing history. Polymer breakthrough occurred in July, and the content became measurable in August. In August, oil production jumped from 18 to 32 BOPD, and the water-oil ratio dropped from 65 to 35. The correlation does not always hold true, however, as Fanny 6, the best well in the project, experienced an oil production jump of 42 BPD in December. The increase has been sustained, and polymer was not measured in the produced water until April of this year.

Due to the early Channelblock treatments, production has responded more rapidly than was predicted in Figure 9. In spite of the fact that eight wells have experienced a sustained production increase, the bulk of the increase in production is coming from only two wells. Obviously, there are two possible extremes in future performance. One would be for a number of the other wells to respond in a similar manner to Fanny 6 and O'Dell 1 which would ensure the economic success of the project. The other case would be for no additional wells to respond, and the two good wells to lose production. As with most fields, it is probable the actual case will be somewhere in between.

Production Problems

The production problems have been limited and for the most part easily corrected. The polymer injection plant caused essentially no problems. It was working correctly within a week of startup and was operated by the lease pumper. In December the injection plant was down during a bitterly cold period due to a power outage. When the plant was restarted, several of the flowlines were frozen, and it was necessary to wait a week or so for warmer weather before these wells could be reactivated. Under normal conditions, the fluid velocity was sufficient to prevent freezeup regardless of the temperature. In September moderate calcium carbonate scaling was discovered in the polymer concentrate discharge lines. This was corrected by adding a scale inhibitor to the injection water at a concentration of 4 ppm.

The biggest problem area occurred in the artificial lift equipment. Most of the wells in the North Stanley Project require that large quantities of fluid be produced if the well is to be economical. This has been accomplished by the use of downhole centrifugal pumps which are designed to work most efficiently at a specific rate, depth, and fluid level and provide minimal flexibility. As a result of the Channelblock and polymer injection, the injection distribution in the reservoir was changed. This caused a change in the fluid levels in a number of the wells. Figure 11 shows the results of a fluid level survey taken in September 1976. A number of the wells began to "pump off" due to the decrease in fluid level. The pumps were lowered in 4 wells, and two wells required a change to smaller submersible pumps in order to stabilize the production. It is not possible to predict the location of fluid level changes in advance. However, based on Kewanee's experience, anyone undertaking a similar project should anticipate such changes occurring and budget sufficient money to correct them.

At the end of polymer injection, the presence of an anaerobic Desulfovibrio (sulfate reducing) bacteria was discovered in the producing wells. Ten wells had 1-10 colonies/ml, 9 wells had 10-100 colonies/ml, and 9 wells had in excess of 100 colonies/ml. There have been no corrosion problems to date. At the end of polymer injection, the oxygen scavenger was eliminated. It is believed that the problem will correct itself when small quantities of oxygen enter the reservoir waters. In the meantime, the bacteria will be watched and a corrosion inhibitor added if the problem becomes more severe.

Future Plans

Figure 12 is the revised Milestone Chart for the project. There have been only minor revisions from last year. The coming year will consist primarily of review and analysis. The first decision to be made will be whether to discontinue injection of fresh water. The polymer slug requires a fresh water pad to prevent formation brine and ferric oxide from degrading the polymer quality. However, two month's injection should be sufficient for that purpose. The primary reason for continuing fresh water past that point is to condition the reservoir for a micellar injection project. Consequently, it will be necessary to define the reservoir heterogeneity and sweep efficiency after polymer.

The study will utilize the salinity maps, polymer breakthrough data, and injection well volumes in order to determine the area contacted by the polymer slug. From these data, an estimate of sweep efficiency will be formulated. The pressure fall-off data will be carefully analyzed to see if the polymer and Channelblock treatments have altered the formation permeability enough to consider a micellar project.

Utilizing the results generated previously, a revised oil production forecast will be made, and economics of the polymer injection project will be calculated. Reports of all work will be included in the final report on the project.

LIST OF FIGURES

FIGURE 1

PLANT DISCHARGE PRESSURE & INJECTION RATE - 1976

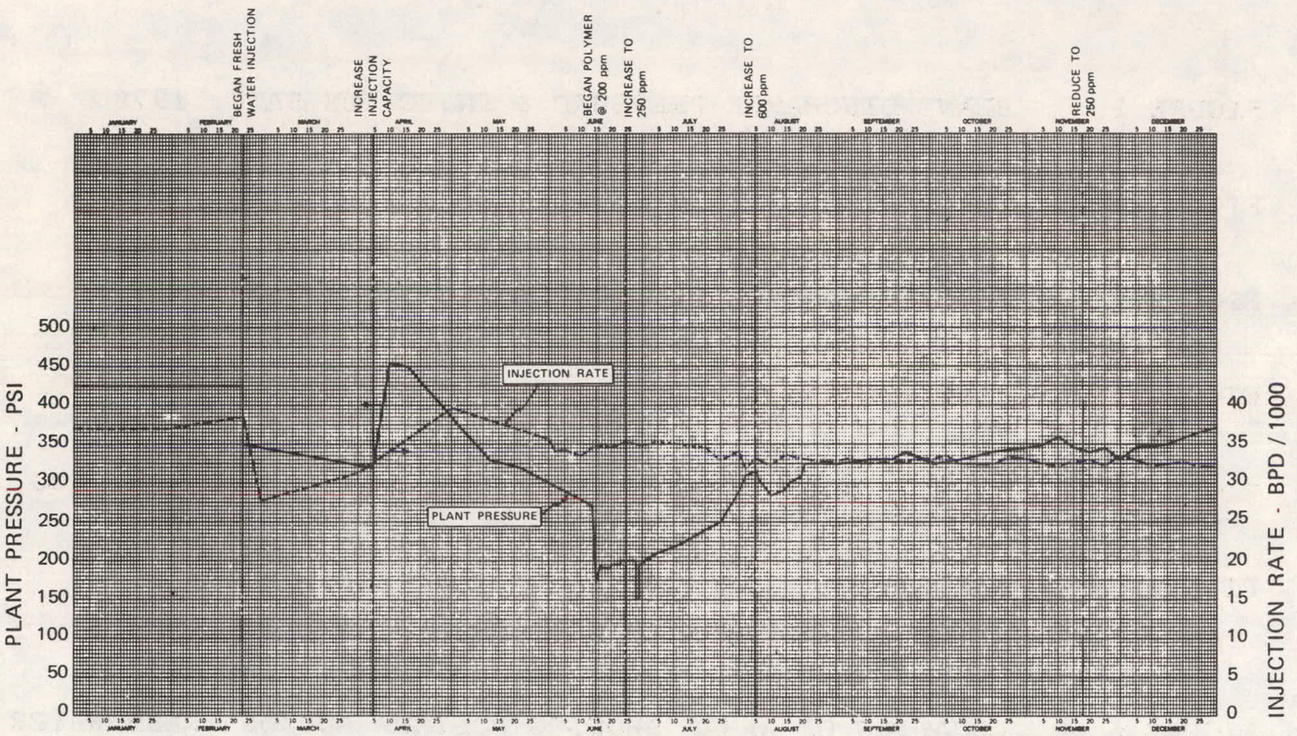


FIGURE 1A

PLANT DISCHARGE PRESSURE & INJECTION RATE - 1977

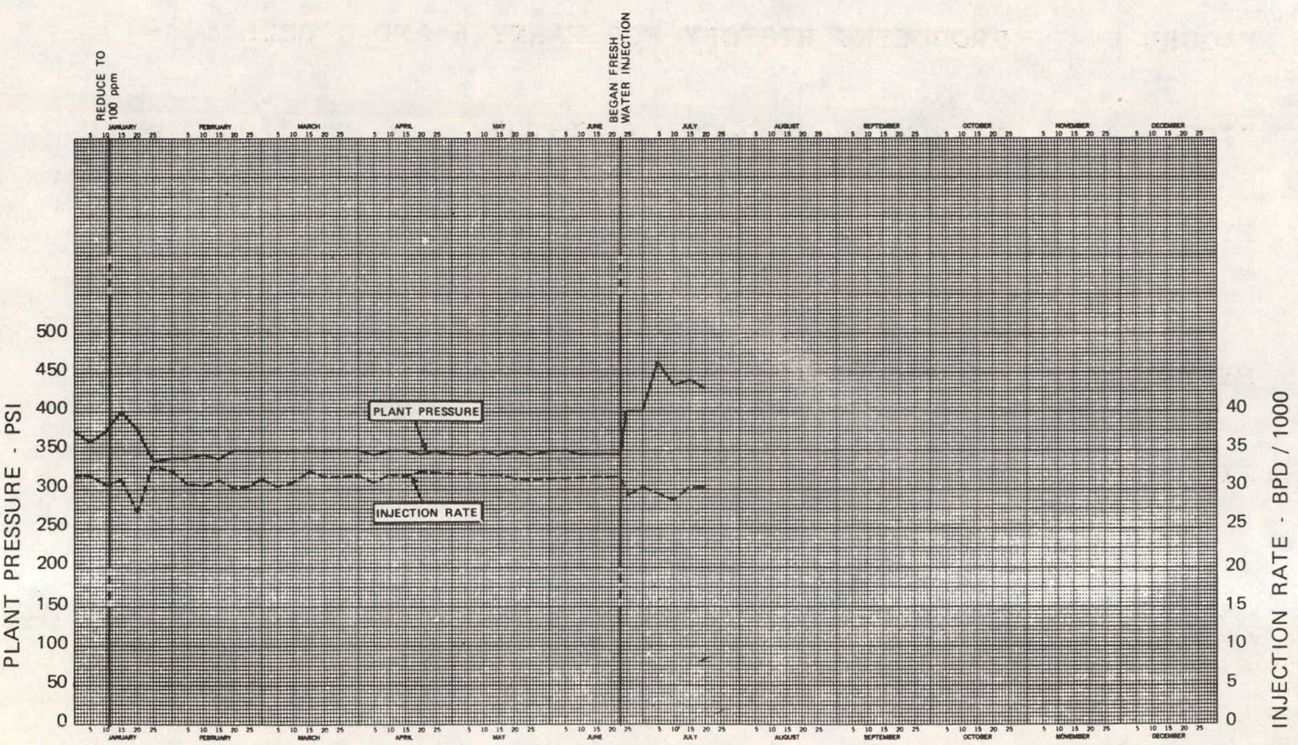


FIGURE 2

LOCATION AND RESULTS OF CHANNELBLOCK TREATMENTS

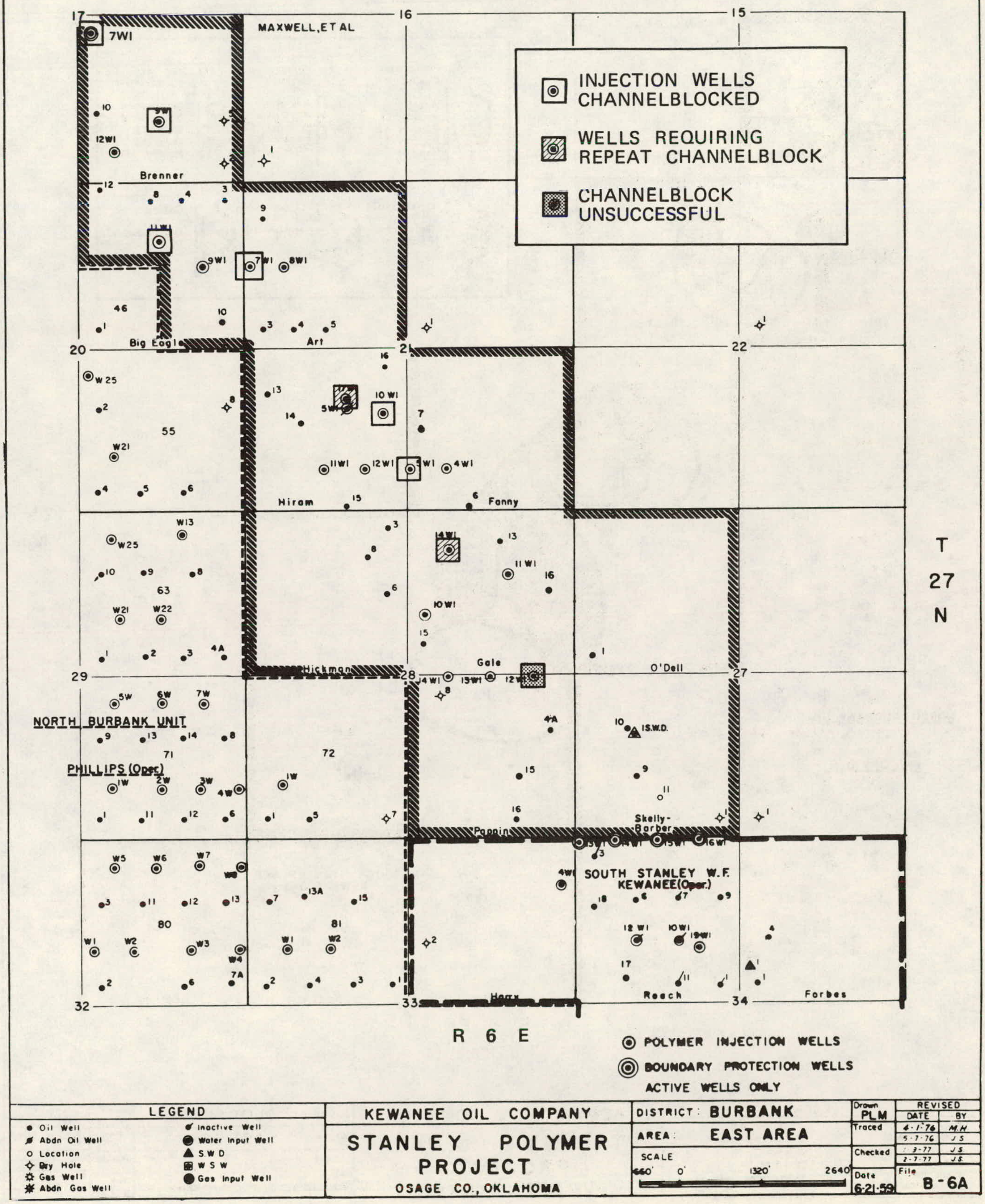
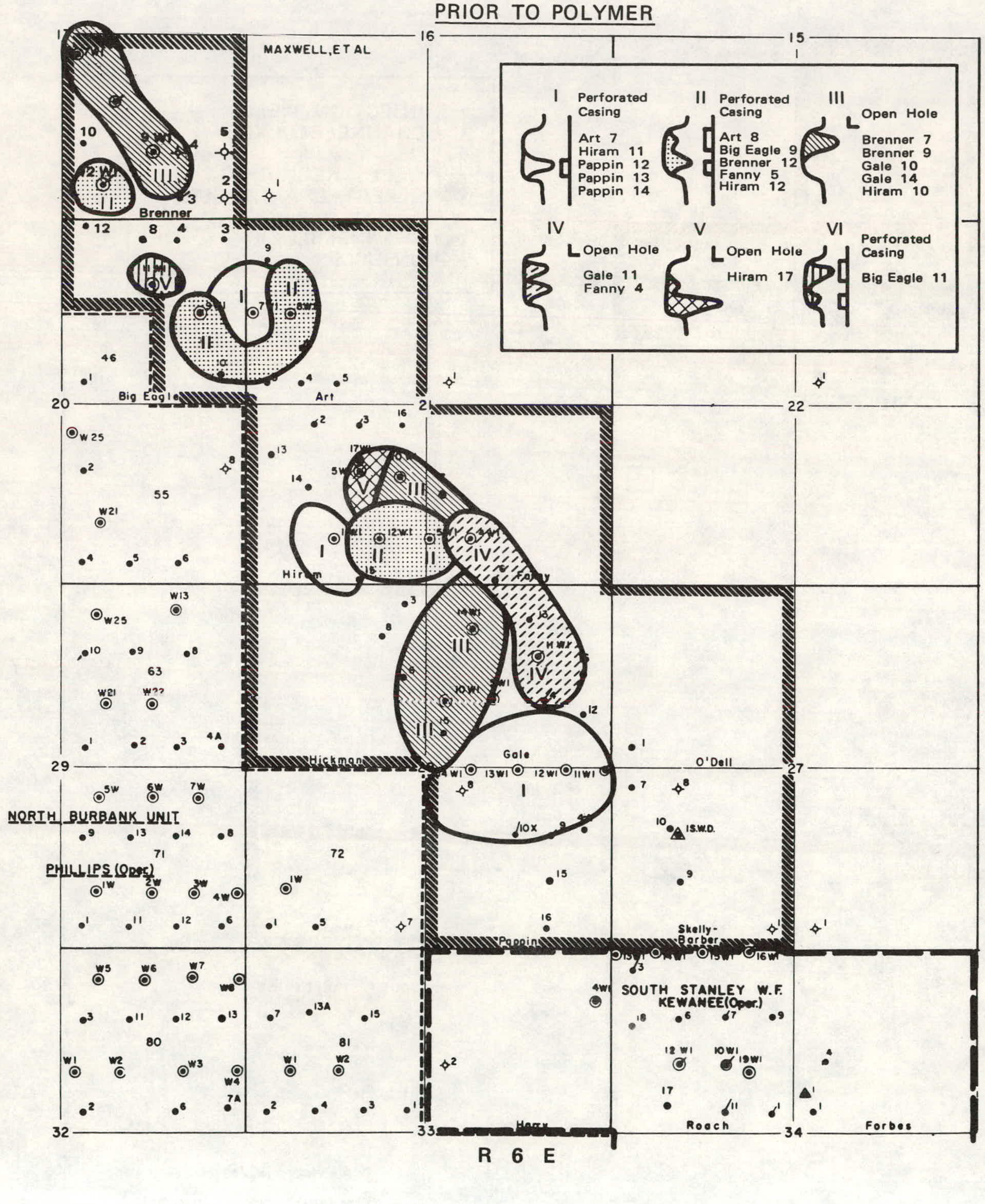


FIGURE 3

DISTRIBUTION OF PROFILE PATTERNS

PRIOR TO POLYMER



LEGEND	
Oil Well	Inactive Well
Abdn Oil Well	Water Input Well
Location	S.W.D
Dry Hole	W S W
Gas Well	Gas Input Well
Abdn. Gas Well	

KEWANEE OIL COMPANY

STANLEY POLYMER PROJECT

OSAGE CO., OKLAHOMA

DISTRICT: BURBANK

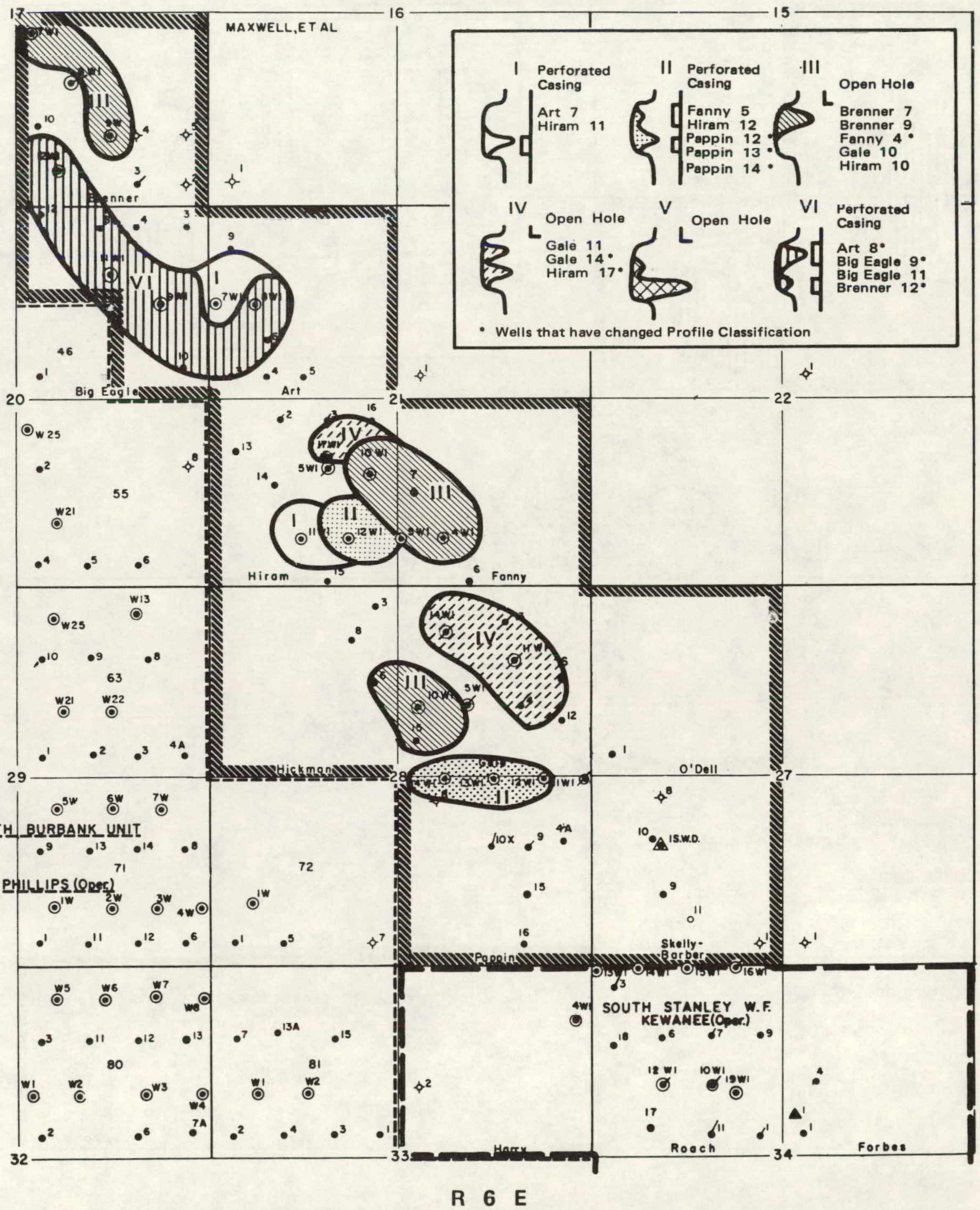
AREA: EAST AREA

SCALE 660' 0' 1320' 2640'

Drawn	PLM	REVISED DATE	BY
Traced		4-1-76	M.H
		5-7-76	J.S
Checked			
Date	6-21-59	File	B-6A

FIGURE 4

DISTRIBUTION OF PROFILE PATTERNS AFTER 600 ppm POLYMER SLUG

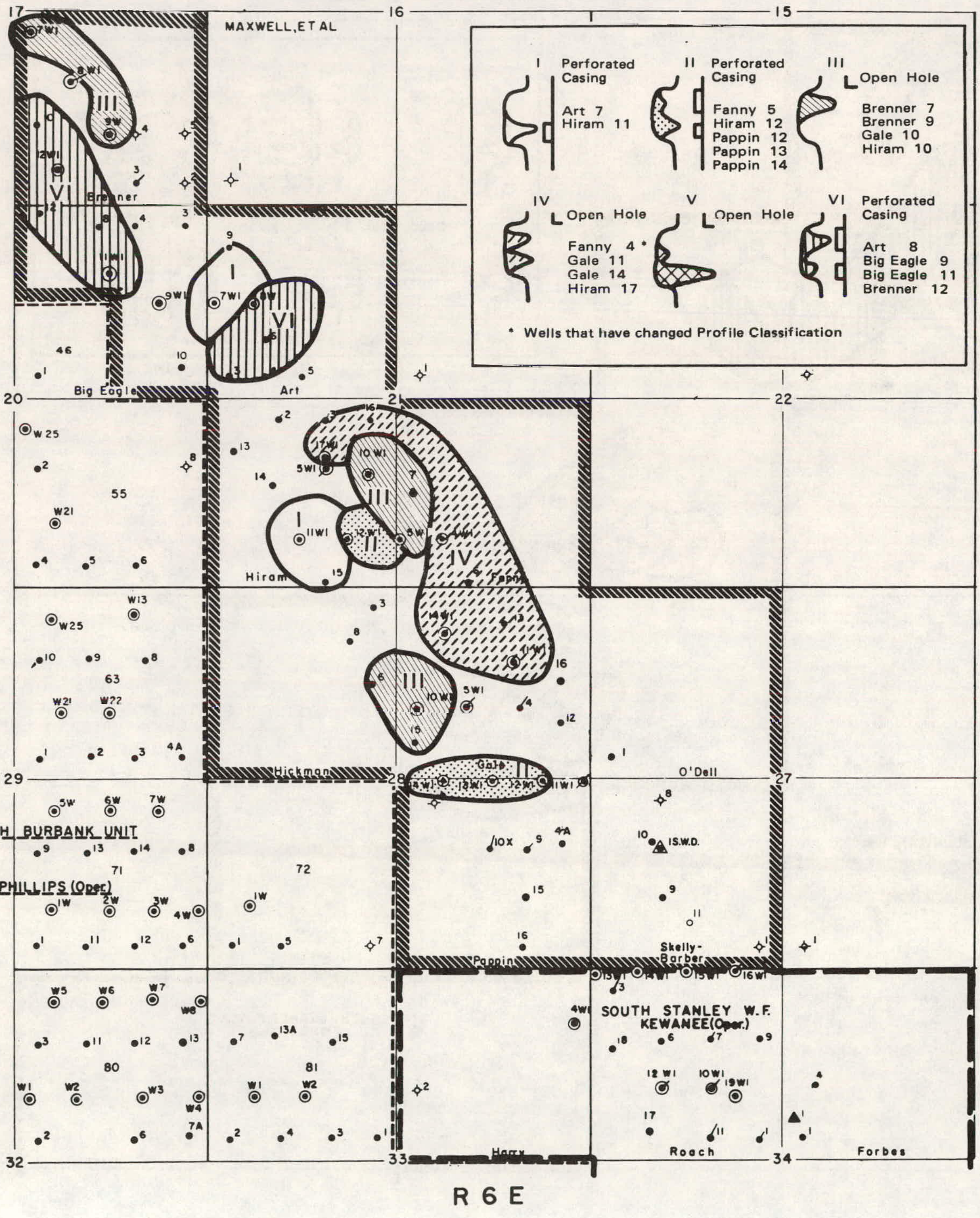


LEGEND		KEWANEE OIL COMPANY	DISTRICT: BURBANK	Drawn PLM	REVISED DATE 3-22-77 BY J.S.
● Oil Well	Inactive Well	STANLEY POLYMER PROJECT	AREA: EAST AREA	Traced	
Abdn. Oil Well	Water Input Well		SCALE: 660' 0' 1320' 2640'	Checked	
○ Location	▲ S.W.D.				
Dry Hole	W.S.W.				
Gas Well	Gas Input Well	OSAGE CO., OKLAHOMA		Date 6-21-59	File B-6A
Abdn. Gas Well					

FIGURE 5

DISTRIBUTION OF PROFILE PATTERNS

LAST MONTH OF POLYMER INJECTION



LEGEND	
Oil Well	Inactive Well
Abdn Oil Well	Water Input Well
Location	S.W.D.
Dry Hole	W S W
Gas Well	Gas Input Well
Abdn Gas Well	

KEWANEE OIL COMPANY

STANLEY POLYMER PROJECT

OSAGE CO., OKLAHOMA

DISTRICT: BURBANK

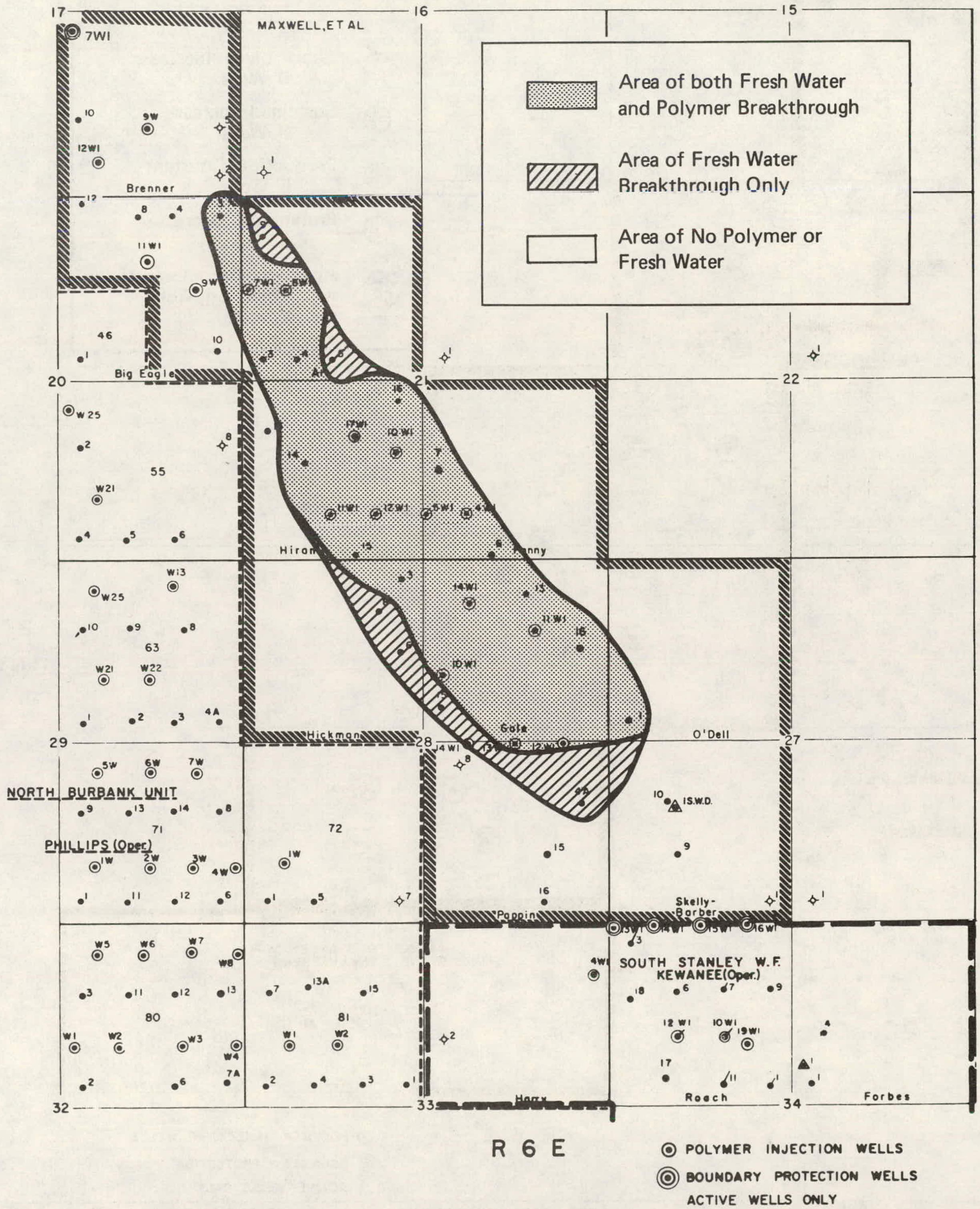
AREA: EAST AREA

SCALE: 660' 0' 1320' 2640'

Drawn PLM; Traced; Checked; Date 6-21-59; REVISED DATE 3-22-77 BY J.S.; File B-6A

FIGURE 6

LOCATION OF AREAS SHOWING POLYMER AND/OR FRESH WATER



LEGEND		KEWANEE OIL COMPANY	DISTRICT: BURBANK	Drawn: PLM	REVISED: DATE 7-15-77, BY J.S.
Oil Well	Inactive Well	STANLEY POLYMER PROJECT	AREA: EAST AREA	Traced	
Abdn Oil Well	Water Input Well			Checked	
Location	S.W.D.	OSAGE CO., OKLAHOMA	SCALE 660 0' 1320' 2640'	Date 6-21-59	File B-6A
Dry Hole	W.S.W.				
Gas Well	Gas Input Well				
Abdn Gas Well					

FIGURE 7

PRODUCTION RESPONSE

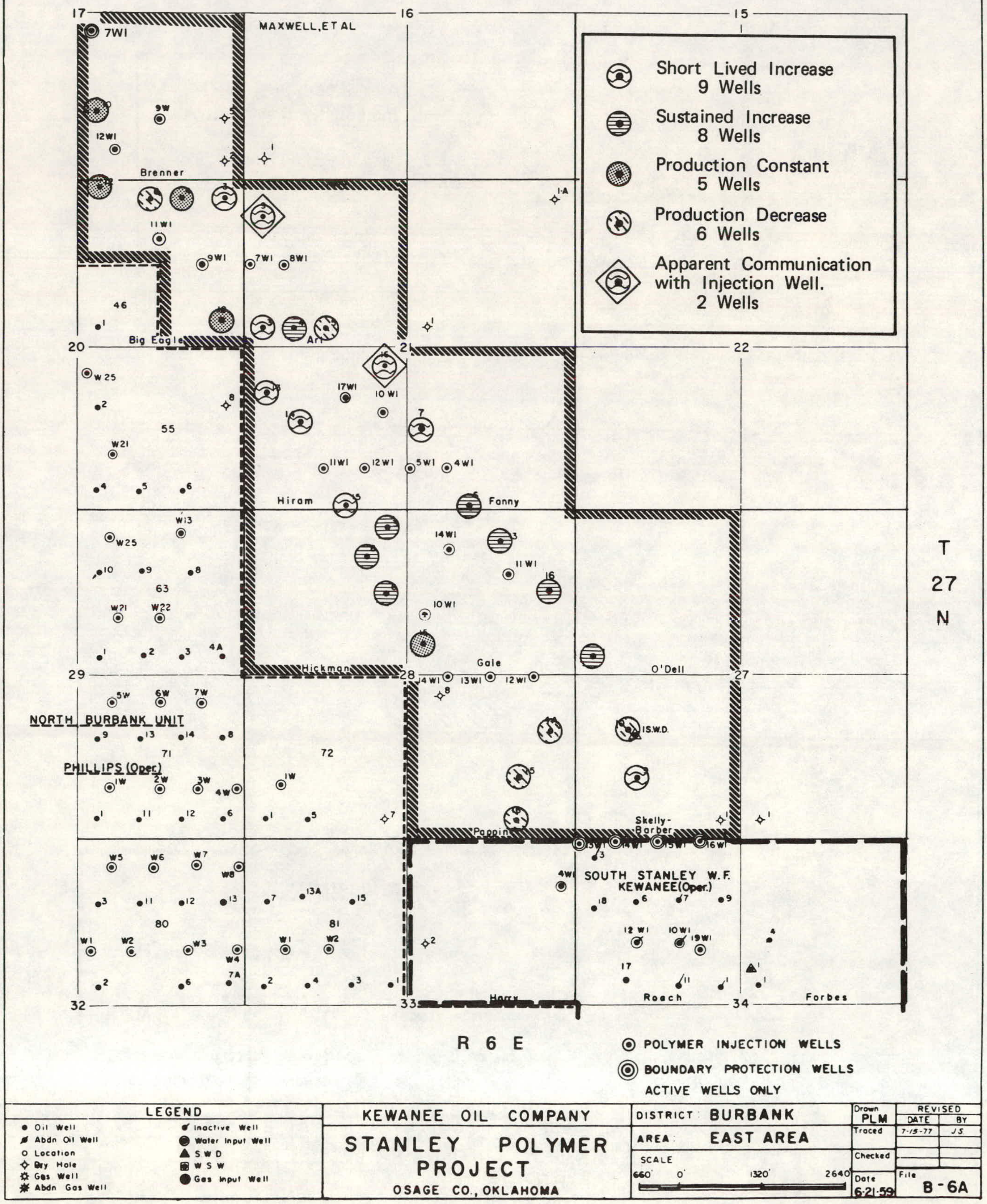
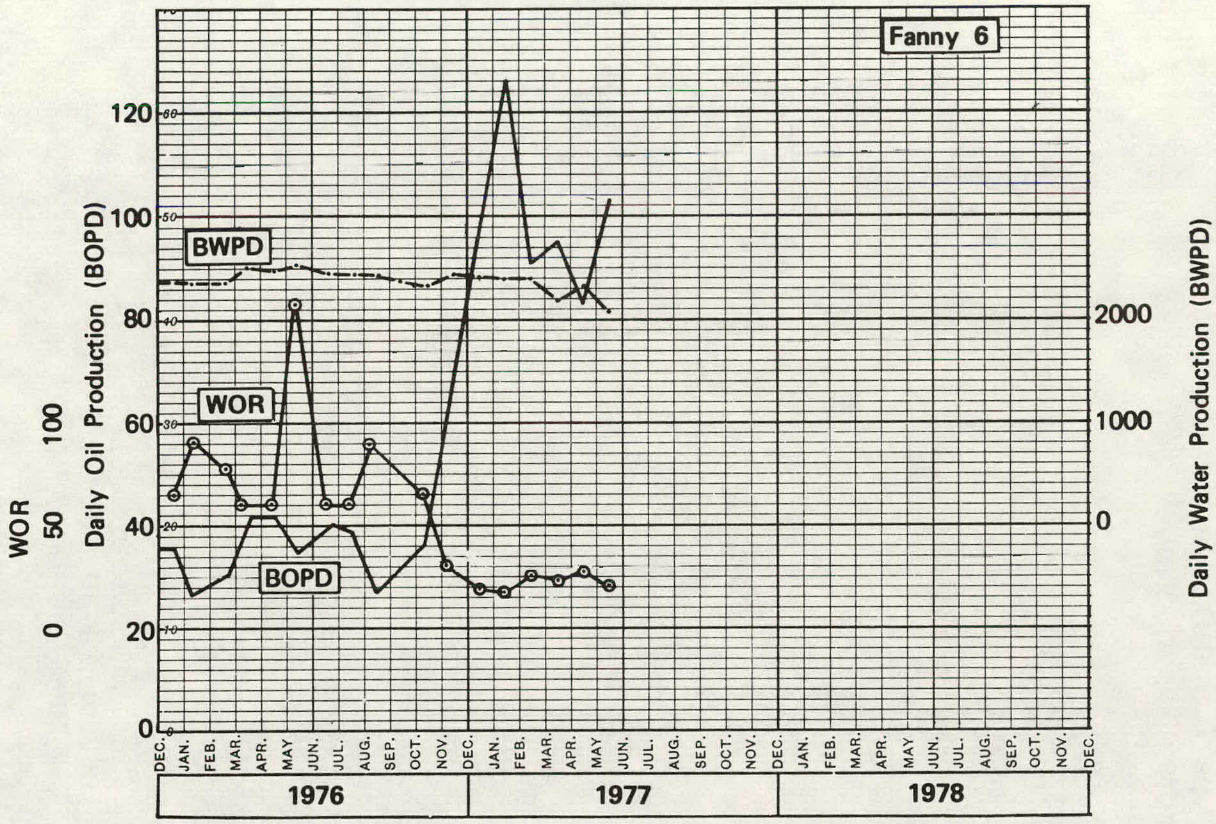


FIGURE 8

PRODUCING HISTORY FOR FANNY 6 AND O'DELL 1



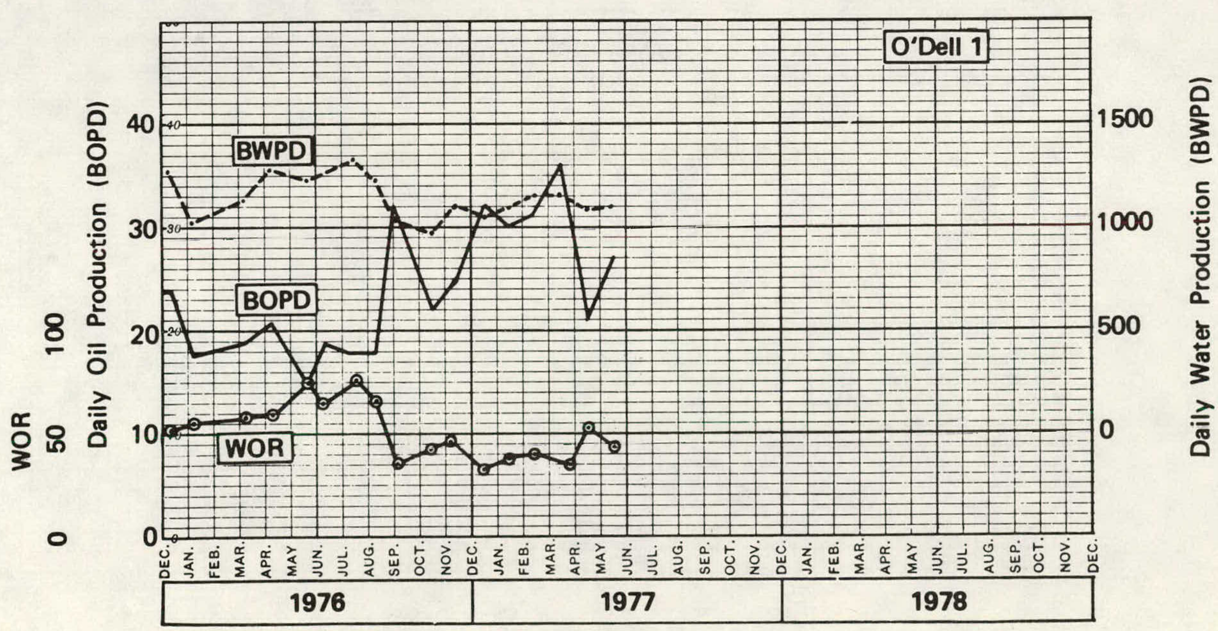


FIGURE 9

NORTH STANLEY PROJECT
INJECTION - PRODUCTION HISTORY

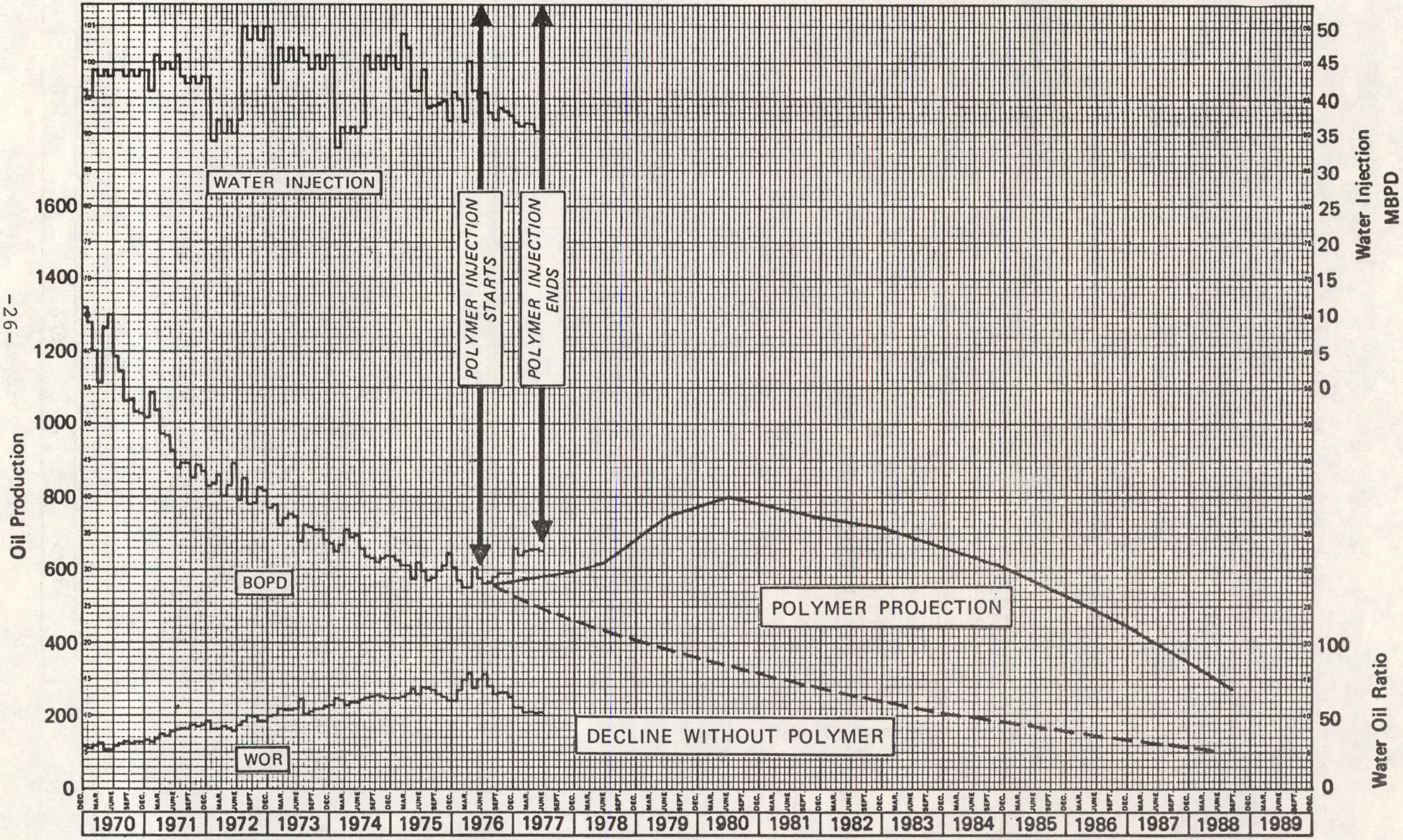
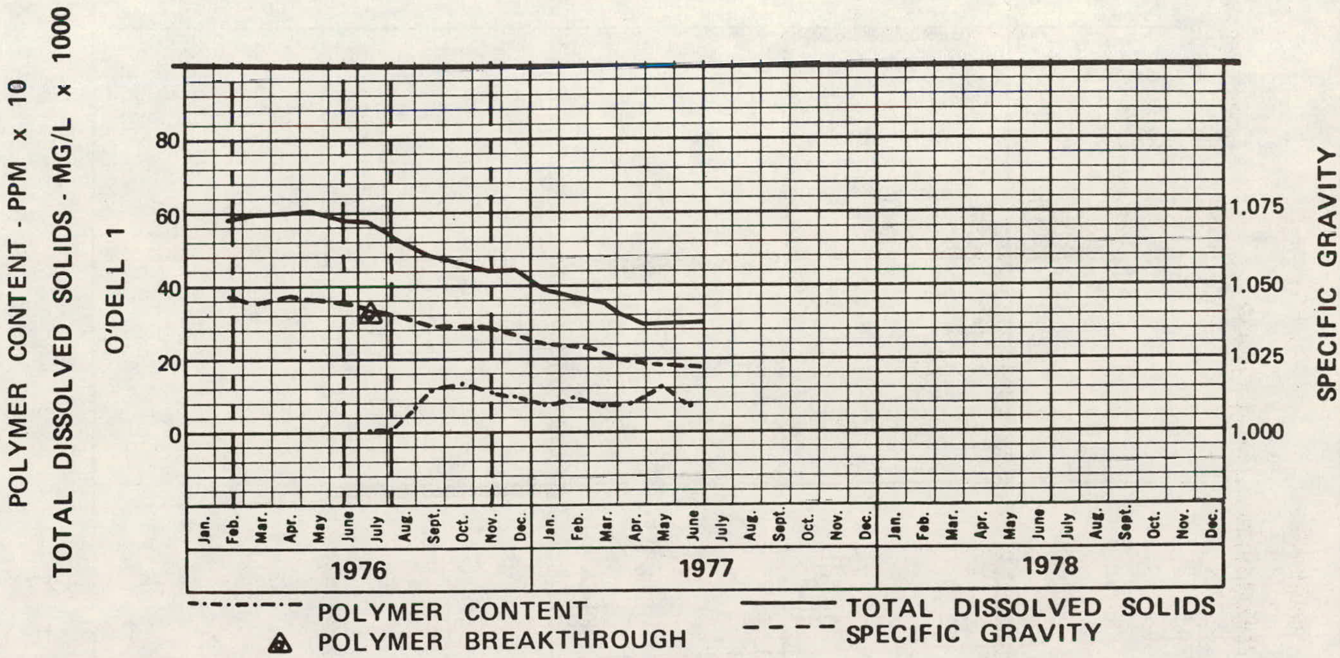


FIGURE 10

COMPARISON OF PRODUCTION TO SALINITY AND POLYMER DETECTION



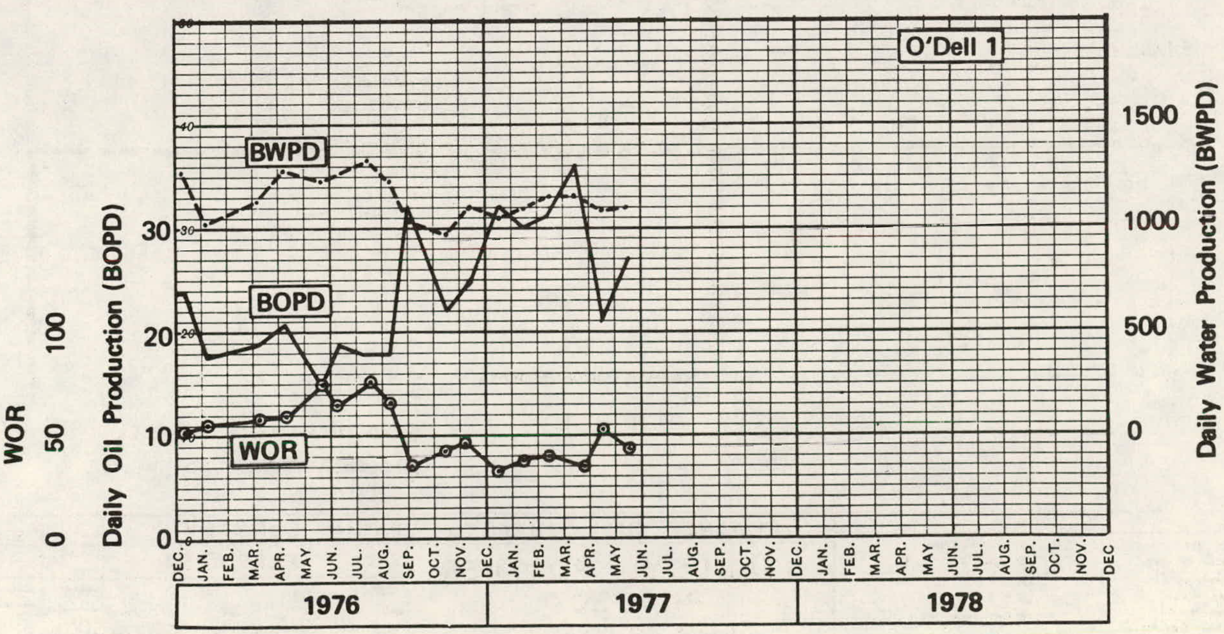


FIGURE 11

CHANGE IN FLUID LEVELS

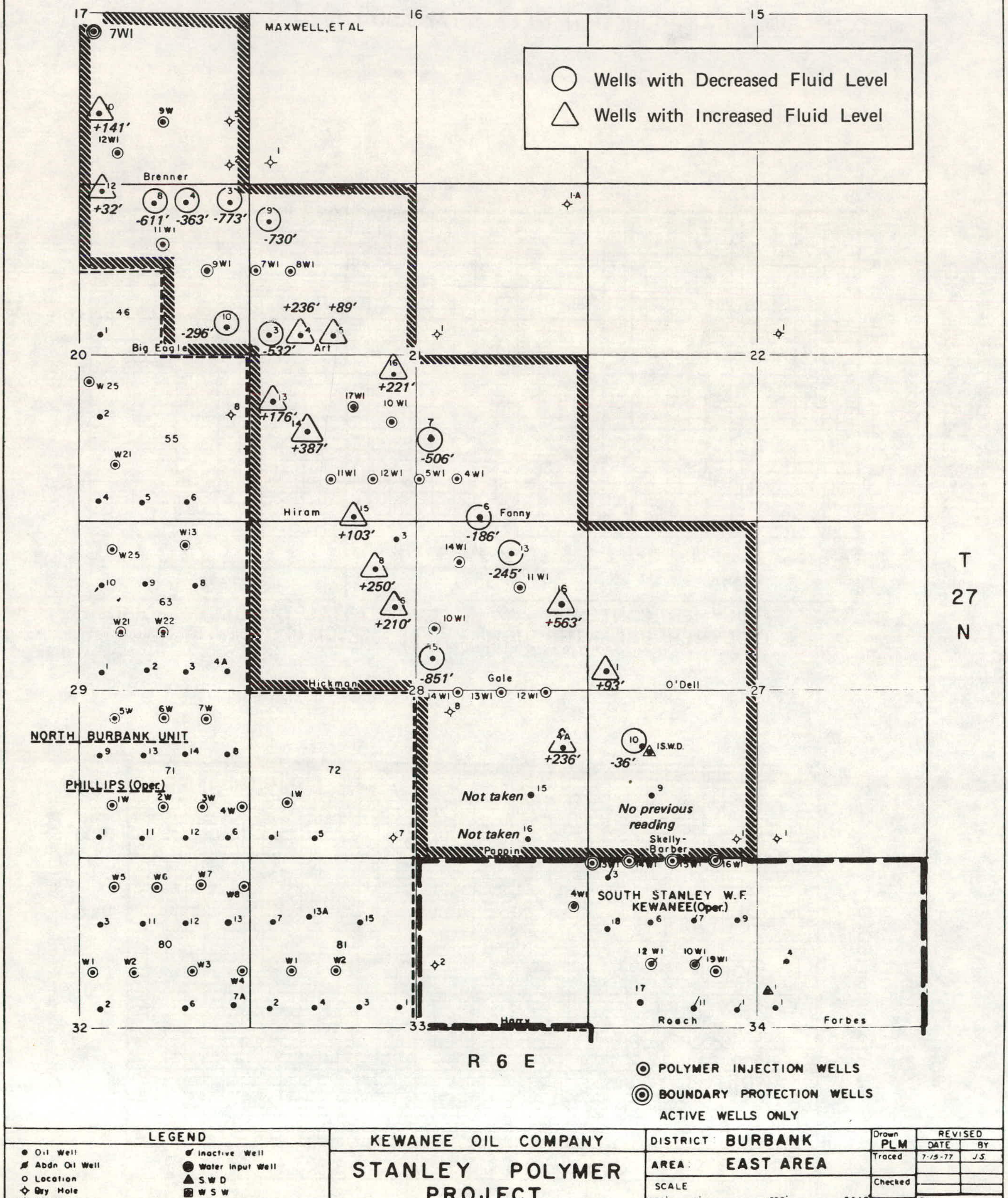
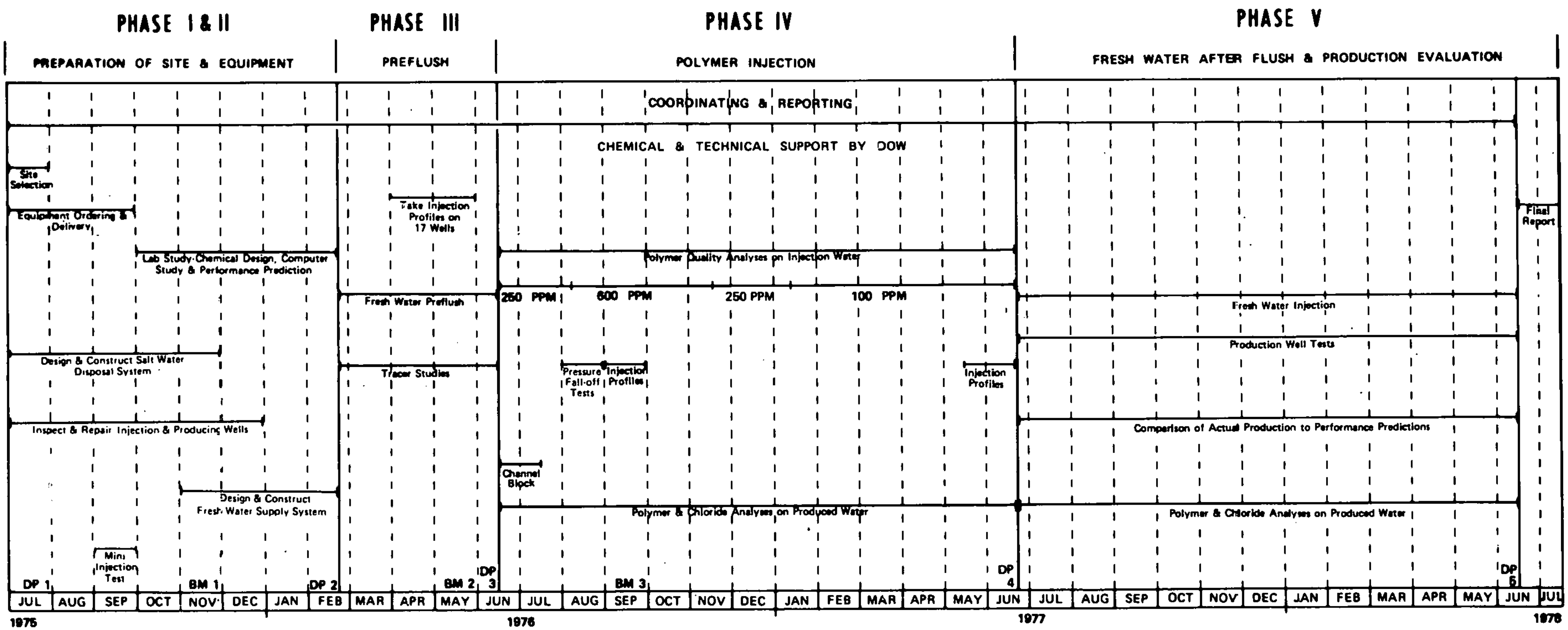


FIGURE 12

MILESTONE CHART

POLYMER INJECTION PROJECT

Controlled Water Flooding



DECISION POINT 1. IS THE TEST SITE ADEQUATE ?
DECISION POINT 2. IS THE TEST SITE READY FOR FRESH WATER INJECTION ?
DECISION POINT 3. IS THE TEST SITE READY FOR POLYMER INJECTION ?
DECISION POINT 4. IS THE POLYMER INJECTION COMPLETE ?
DECISION POINT 5. IS ADDITIONAL EVALUATION DATA NEEDED ?

BENCH MARK 1. ATTAINMENT OF ADEQUATE PRODUCED WATER DISPOSAL CAPACITY
BENCH MARK 2. COMPLETION OF INJECTION PROFILE SURVEYS DURING FRESH WATER INJECTION
BENCH MARK 3. COMPLETION OF TWO MONTHS OF POLYMER INJECTION

Revision 2 June 26, 1977

LIST OF TABLES

TABLE 1

POLYMER INJECTION HISTORY

DATE STARTED	NUMBER OF DAYS	CONCENTRATION PPM	AVERAGE POUNDS PER DAY	TOTAL POUNDS
6-16-76	5	200	2339	11,695
6-21-76	44	250	2924	134,505
8-5-76	14	600	6454	90,356
8-19-76	82	625	6723	551,308
11-9-76	9	600	6454	58,086
11-18-76	13	250	2883	34,592
12-1-76	33	290	3344	110,347
1-3-77	9	250	2883	23,061
1-11-77	163	100	1109	180,820
TOTAL	372	285	3212	1,194,770

TABLE 2

CHRONOLOGY OF EVENTS

Date	Event
6/16/76	Started polymer injection at 200 ppm.
6/21/76	Increased polymer concentration to 250 ppm.
7/05/76	Completed Channelblock on Hiram 17 WI.
7/16/76	Completed Channelblock on Fanny 5 WI.
7/16/76	Ran positive flocculation test on Big Eagle 3, Gale 13, Hiram 15, and O'Dell 1.
7/28/76	Completed Channelblock on Gale 14 WI.
7/29/76	Perforated upper intervals on Pappin 12 WI, 13 WI, and 14 WI.
7/31/76	Completed Channelblock on Hiram 10 WI.
8/02/76	Completed Channelblock on Art 7 WI.
8/02/76	Completed Channelblock on Brenner 9 WI.
8/05/76	Increased polymer concentration to 600 ppm.
8/08/76	Completed Channelblock on Brenner 9 WI.
8/19/76	Increased polymer concentration to 625 ppm.
8/23/76	Completed re-Channelblock on Hiram 17 WI.
9/01/76	Ran positive flocculation test on Hiram 14 and 16.
9/20/76	Attempted to increase injection rate to 35,000 BPD causing injection pressure to increase from 340 to 500 psi. Made decision to limit plant pressure to 350 psi.
9/20/76	Found moderate calcium carbonate scaling in polymer concentration discharge lines. Added scale inhibitor at 4 ppm.
9/20/76	Found scaling in Big Eagle 3 and Gale 13.
9/30/76	Completed shooting fluid levels. Some wells beginning to "pump off."
9/30/76	Completed lowering pumps in Art 3, Art 5, Big Eagle 3, and Gale 13.
9/30/76	Completed change to smaller submersible pumps in Gale 13 and Art 4.
9/30/76	Recorded first positive oil production response 19 BPD tertiary oil in September.
10/21/76	Reactivated Big Eagle 11 WI.
10/30/76	Completed Channelblock on Big Eagle 11 WI.
10/30/76	Averaged 42 BPD tertiary oil during October.
11/09/76	Reduced concentration to 600 ppm polymer.
11/11/76	Completed Channelblock treatment on Pappin 12 WI; treatment was unsuccessful due to high line pressure.
11/16/76	Completed second round of pressure fall-off tests.
11/17/76	Completed injectivity profiles.
11/17/76	Installed flow regulator coil on Pappin 12 WI.
11/18/76	Reduced polymer concentration to 250 ppm.
11/20/76	Recorded three wells showing more than 100 ppm polymer, Hiram 15, Hiram 16, and O'Dell 1.
11/30/76	Averaged 45 BPD tertiary oil during November.
12/01/76	Increased polymer concentration to 290 ppm.
12/30/76	Averaged 57 BPD tertiary oil during December.

Date	Event
1/03/77	Reduced polymer concentration to 250 ppm.
1/11/77	Reduced polymer concentration to 100 ppm.
1/30/77	Averaged 130 BPD tertiary oil in January.
2/01/77	Made decision to limit plant discharge pressure to 350 psi.
2/01/77	Recognized severe polymer and fresh water breakthrough in Hiram 16. Decided to re-Channelblock Hiram 17 WI.
2/17/77	Completed re-Channelblocking Gale 14 WI.
2/28/77	Averaged 116 BPD tertiary oil in February.
3/05/77	Completed re-Channelblocking Hiram 17 WI.
3/15/77	Hiram 16 polymer content decreased from 240 ppm to 95 ppm.
3/22/77	Repaired casing leak in Hiram 15.
3/31/77	Averaged 130 BPD tertiary oil in March.
4/13/77	Received results of water analysis showing anaerobic corrosive bacteria in produced water. Started treating with Visco 1152.
4/14/77	Polymer in Gale 13 decreased from 155 ppm to 16 ppm.
4/30/77	Averaged 144 BPD tertiary oil in April.
5/15/77	Recorded 2 wells in excess of 150 ppm, 3 wells 100-150 ppm, 4 wells 10-100 ppm, 3 wells 0-10 ppm.
5/31/77	Averaged 153 BPD tertiary oil in May.
6/01/77	Re-Channelblocked Gale 14 WI.
6/10/77	Completed pressure fall-off tests.
6/16/77	Completed injection profile surveys.
6/22/77	Terminated polymer injection.
6/22/77	Injection pressure jumped to 385 psi from 345 psi. Vol dropped to 29,000 from 31,000 BWPD.
6/25/77	Installed throttling valves on Hiram 17 WI, Gale 14 WI, Gale 11 WI, Art 8 WI, and Pappin 12 WI to limit injection in those wells.
7/15/77	Injection pressure stabilized at 430 psi; rate stabilized at 30,000 BWPD.

TABLE 3

SUMMARY OF CHANNEL BLOCK TREATMENTS

WELL		PRIOR TO TREATMENT			CONCLUSION OF TREATMENT			NOVEMBER, 1976			VOLUME OF TREATMENT
		Injection Rate (BPD)	Wellhead Pressure (psi)	Injectivity Index (B/psi)	Injection Rate (BPD)	Wellhead Pressure (psi)	Injectivity Index (B/psi)	Injection Rate (BPD)	Wellhead Pressure (psi)	Injectivity Index (B/psi)	
BRENNER	7 WI	1277	70	.95	500	250	.32	755	300	.48	+/-25,000
BRENNER	9 WI	3315	169	2.30	2210	270	1.44	1542	300	.98	37,180
BIG EAGLE	11 WI	3400	260	2.21	1250	325	.78	1531	320	.96	117,659
ART	7 WI	2823	170	1.95	1781	274	1.15	3204	290	2.04	42,236
HIRAM	10 WI	4936	110	3.56	2010	192	1.37	1149	310	.72	65,803
HIRAM	17 WI	4937	105	3.60	3400	275	2.20	3174	320	2.00	68,068
FANNY	5 WI	3348	167	2.30	2112	192	1.43	2418	300	1.52	25,740
GALE	14 WI	4670	125	3.36	1119	235	1.28	4505	300	2.88	75,636
PAPPIN	12 WI*	3400	310	2.17	+4000	350		2846*	250	1.89	>100,000

* Treatment - unsuccessful, installed flow coil to reduce rate - December Injection Figure

TABLE 4

COMPARISON OF PRESSURE FALL–OFF CALCULATIONS

FRESH WATER VS 600 PPM POLYMER

	Stabilized Injection Rate (B/D) W/O Polymer	W Polymer	% Difference	Slope (psi/cycle) W/O Polymer	W Polymer	% Difference	Permeability (Md) W/O Polymer	W Polymer	% Difference
Art 7 *	2175	3205	+47.4	45	176	+291.1	65.5	94.6	+44.4
8	990	1784	+80.2	72	94	+30.6	22.0	116.36	+429.0
Big Eagle 9	450	484	+7.6	184	100	+45.7	3.85	29.2	+658.0
Brenner 9 *	1990	1542	-22.5	19	93	+389.5	140.0	84.9	-39.4
Fanny 4	1825	1874	+2.69	109	176	+61.5	33.3	35.33	+6.1
5 *	2130	2419	+13.6	8.5	52	+512.0	335.0	238.3	-28.9
Hiram 11	1075	665	-38.14	25	40	+60.0	69.9	103.6	+48.2
12	1025	150	-85.4	27	85	+215.0	59.9	4.92	-91.8
17 *	3000	3175	+5.8	30	62	+107.0	13.4	137.0	+922.4
Pappin 12 *	3275	1844	-43.7	38	37	-2.63	114.0	252.0	+122.2
13	1325	967	+27.0	118	138	+16.95	28.9	36.91	+27.7
14	1025	90	+91.23	42	130	+210.0	41.8	4.54	-89.1

	Skin Effect W/O Polymer	W Polymer	Difference	Stabilized Injection Rate Initial Pressure W/O Polymer	W Polymer	% Difference	Flow Efficiency W/O Polymer	W Polymer	% Difference
Art 7 *	-0.17	-5.79	-5.62	1.73	2.19	-26.6	1.02	11.6	+1037.0
8	-3.04	-4.26	-1.22	0.8	1.25	+56.3	1.67	2.35	+40.7
Big Eagle 9	-5.23	-5.6	-.37	0.32	0.33	+3.13	4.63	8.48	+83.2
Brenner 9 *	4.44	-5.28	-9.72	1.58	1.07	-32.3	0.66	3.09	+368.2
Fanny 4	-5.32	-5.28	+.04	1.45	1.34	-7.6	4.61	6.44	+39.7
5 *	11.43	-4.3	-15.73	1.6	1.67	+4.4	0.47	2.33	+396.0
Hiram 11	5.26	-4.39	-9.65	0.86	0.46	-46.5	0.56	2.18	+289.3
12	0.98	-4.78	-5.76	0.77	0.1	-87.0	0.89	3.27	+267.0
17 *	-5.34	-5.4	-.06	2.62	2.2	-16.0	-5.5	2.91	+153.0
Pappin 12 *	1.39	-4.75	-6.14	2.51	1.33	-47.0	0.86	1.78	+107.0
13	-3.25	-5.11	-1.86	0.93	0.64	-31.2	2.22	4.37	+96.8
14	-3.21	-4.61	-1.4	0.74	0.06	-91.9	1.54	3.03	+96.7

* Wells that were channelblocked.

TABLE 5

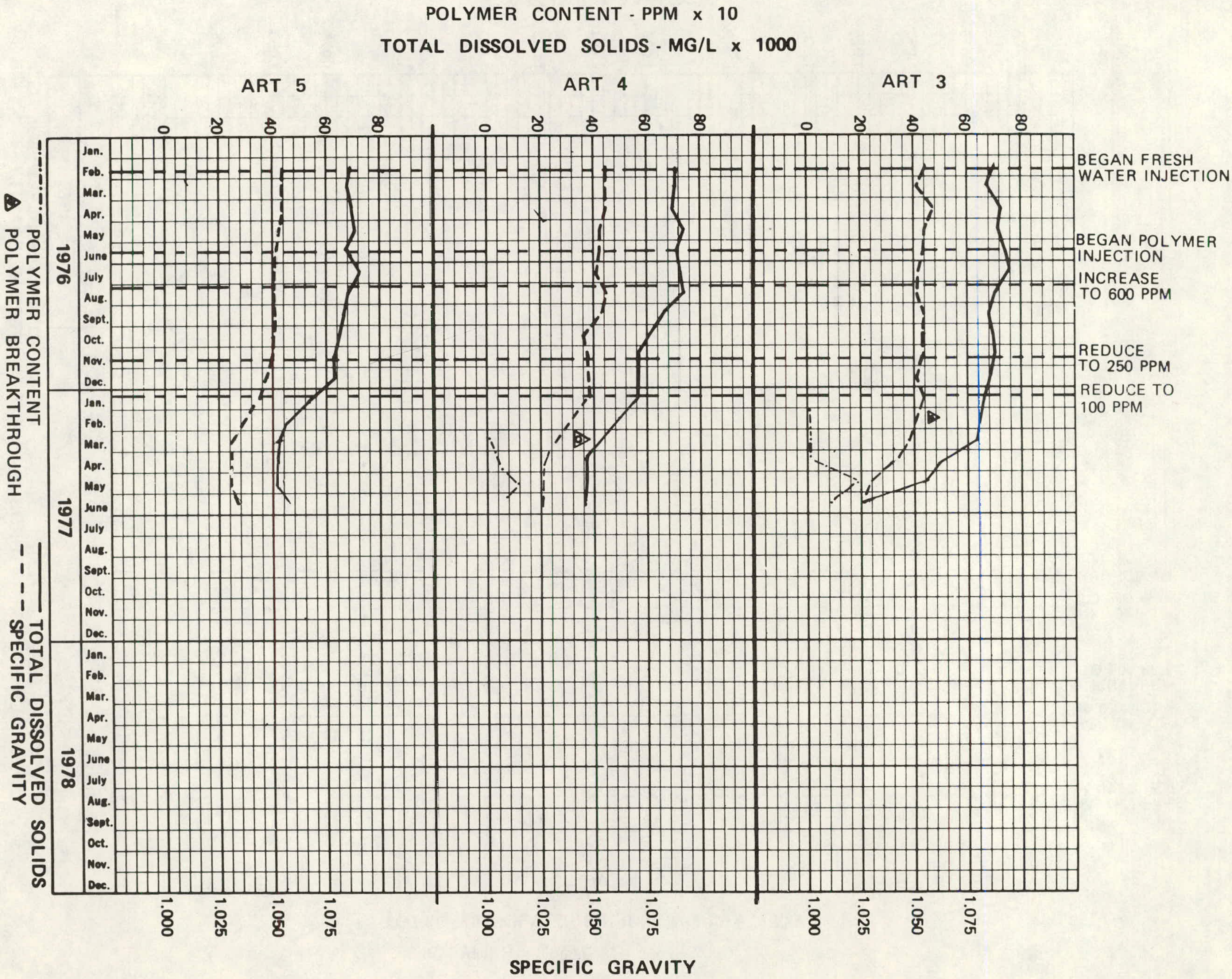
POLYMER AND FRESH WATER BREAKTHROUGH

Well	Days Until Polymer Breakthrough	Days Until Fresh Water Breakthrough
Art 3	252	271
Art 4	273	210
Art 5 ***	No Polymer	210
Art 9 ***	No Polymer	144
Big Eagle 3	21	29
Big Eagle 4	No Polymer	No Dilution
Big Eagle 8	No Polymer	No Dilution
Big Eagle 10	No Polymer	No Dilution
Big Eagle 12	No Polymer	No Dilution
Brenner 10	No Polymer	No Dilution
Fanny 6	303	112
Fanny 7	188	112
Gale 13	31	42
Gale 15	No Polymer	210 *
Gale 16	158	144
Hickman 3	230	175
Hickman 6 ***	No Polymer	175
Hickman 8 ***	No Polymer	159 *
Hiram 13	No Polymer	No Dilution
Hiram 14	77	98
Hiram 15	21	31
Hiram 16	97	98
O'Dell 1	31	84
Pappin 4A	No Polymer	112
Pappin 15	No Polymer	No Dilution
Pappin 16	No Polymer	No Dilution
Skelly Barber 9	No Polymer	No Dilution
Skelly Barber 10	No Polymer	No Dilution **

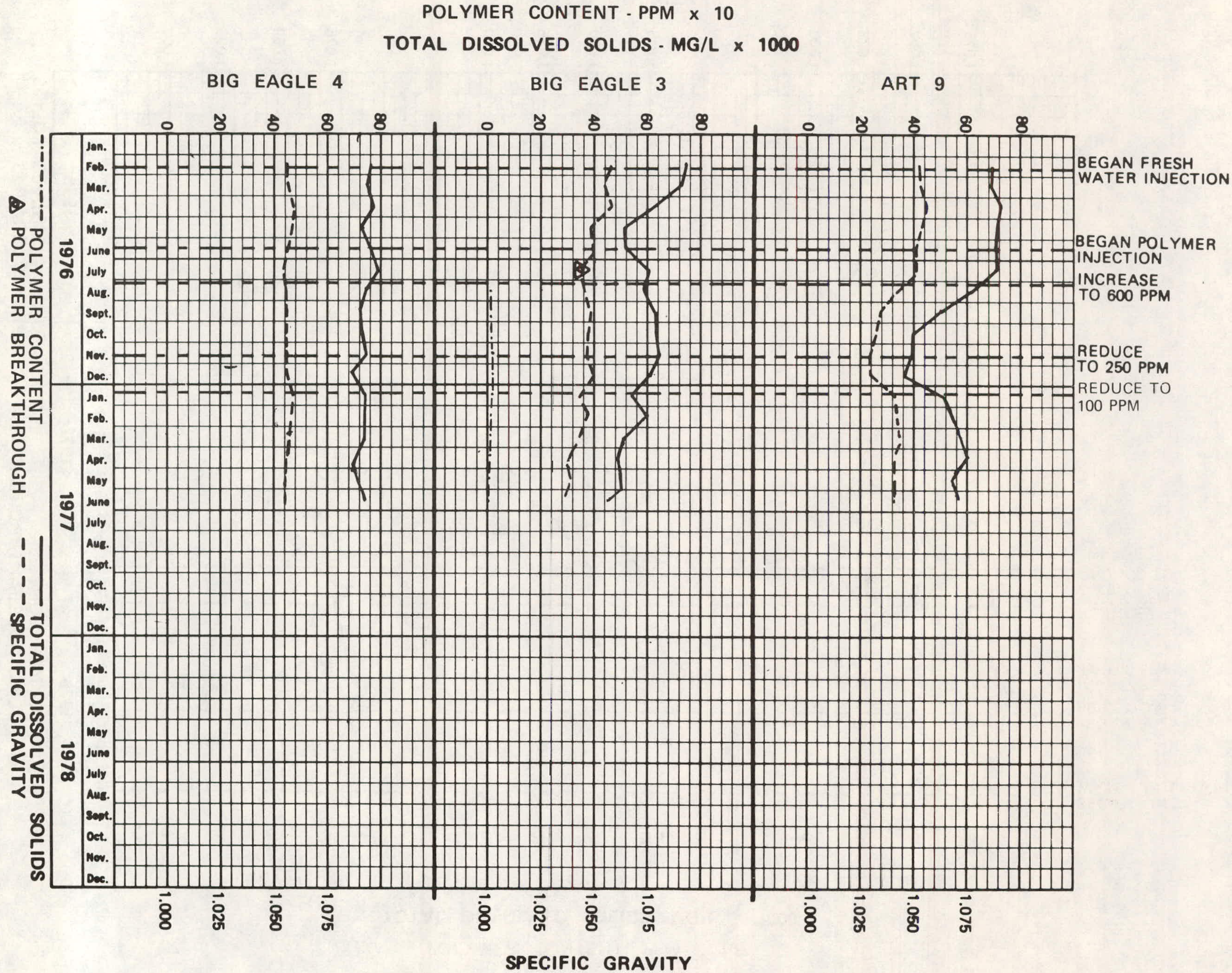
* Very minor dilution.

** Salinity dropped from reservoir original level of 120,000 to average of 70,000 which is the same as other wells in the area.

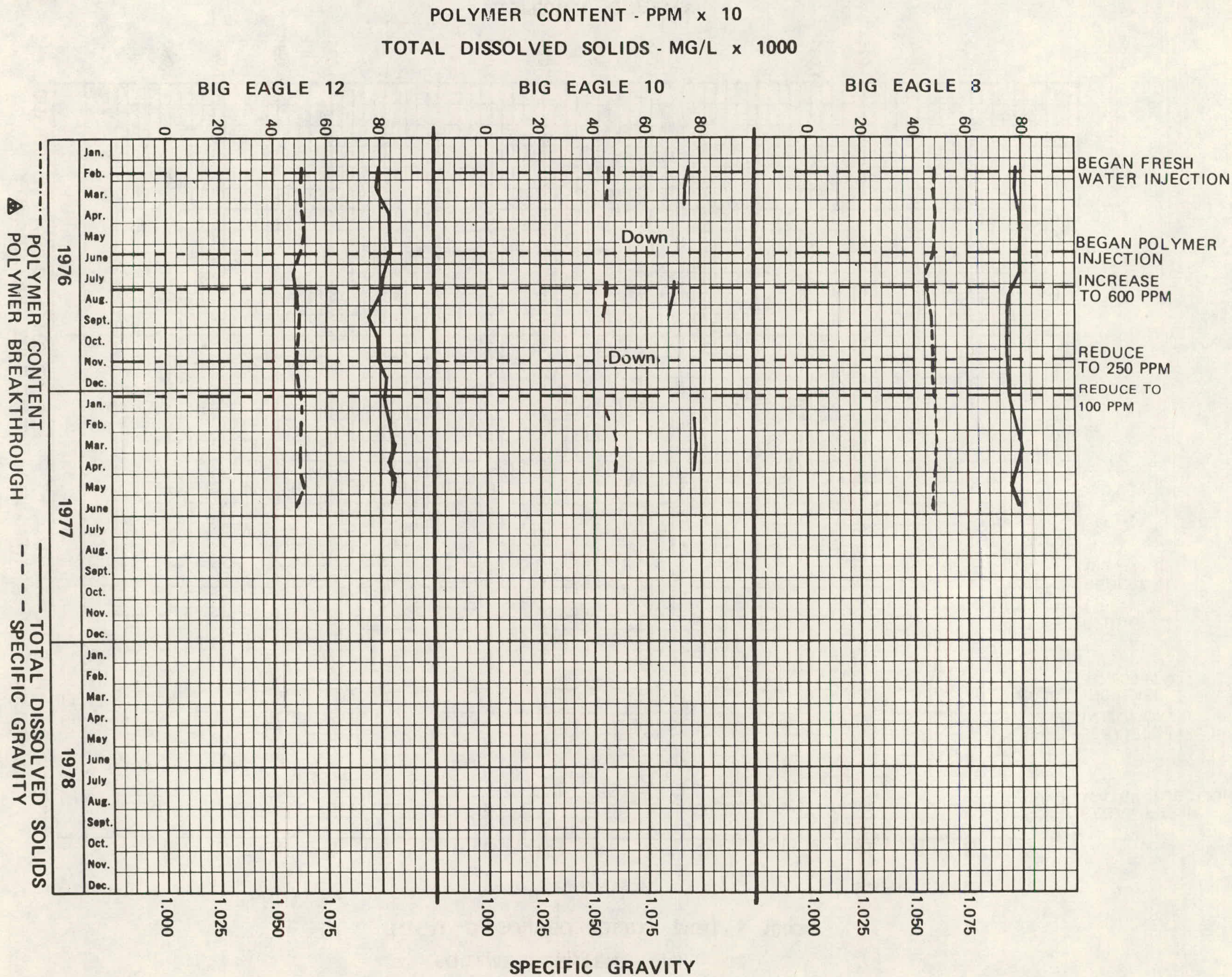
*** Positive clay flocculation tests, but concentration was too small to measure in the lab.



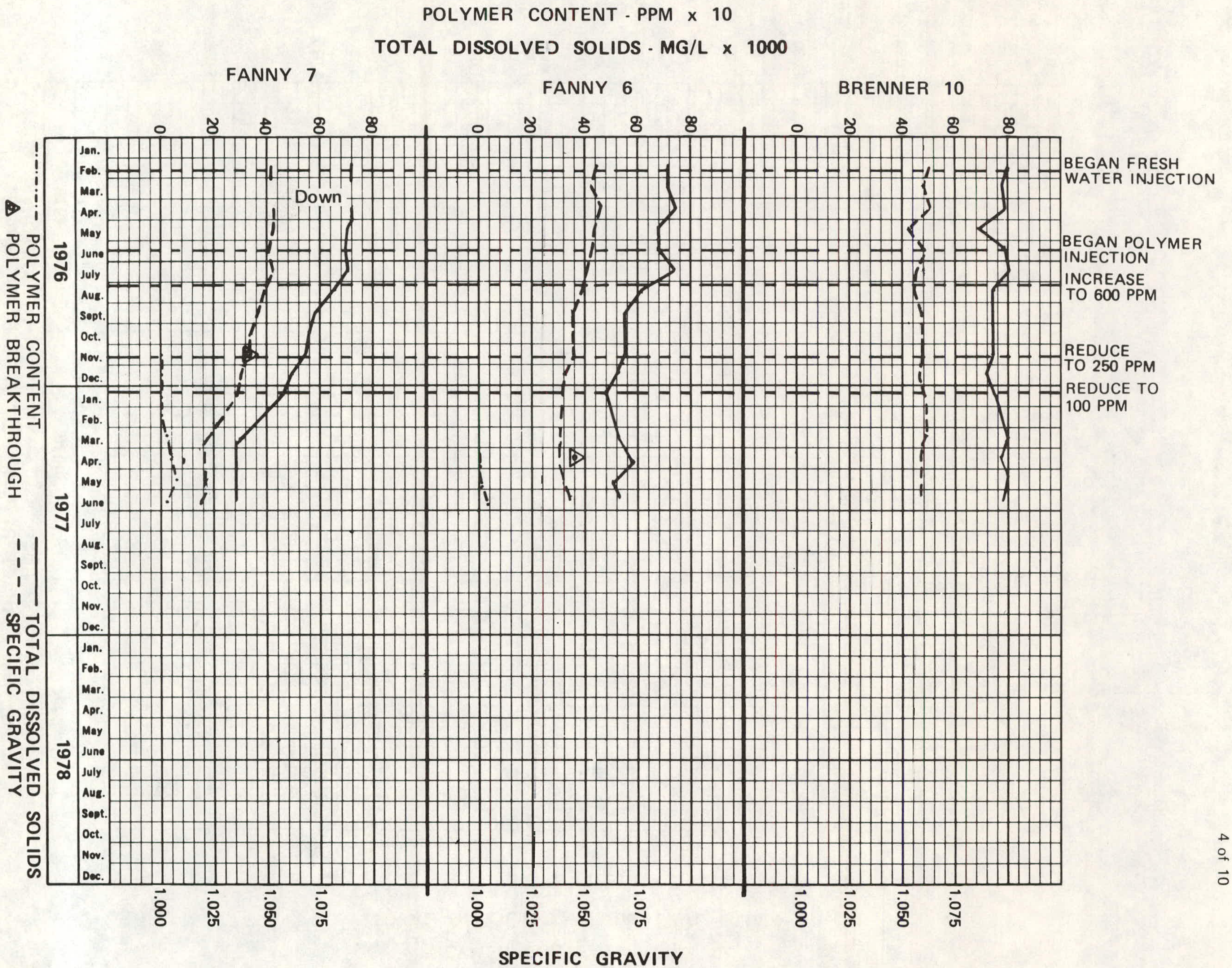
PRODUCED WATER - TOTAL DISSOLVED SOLIDS



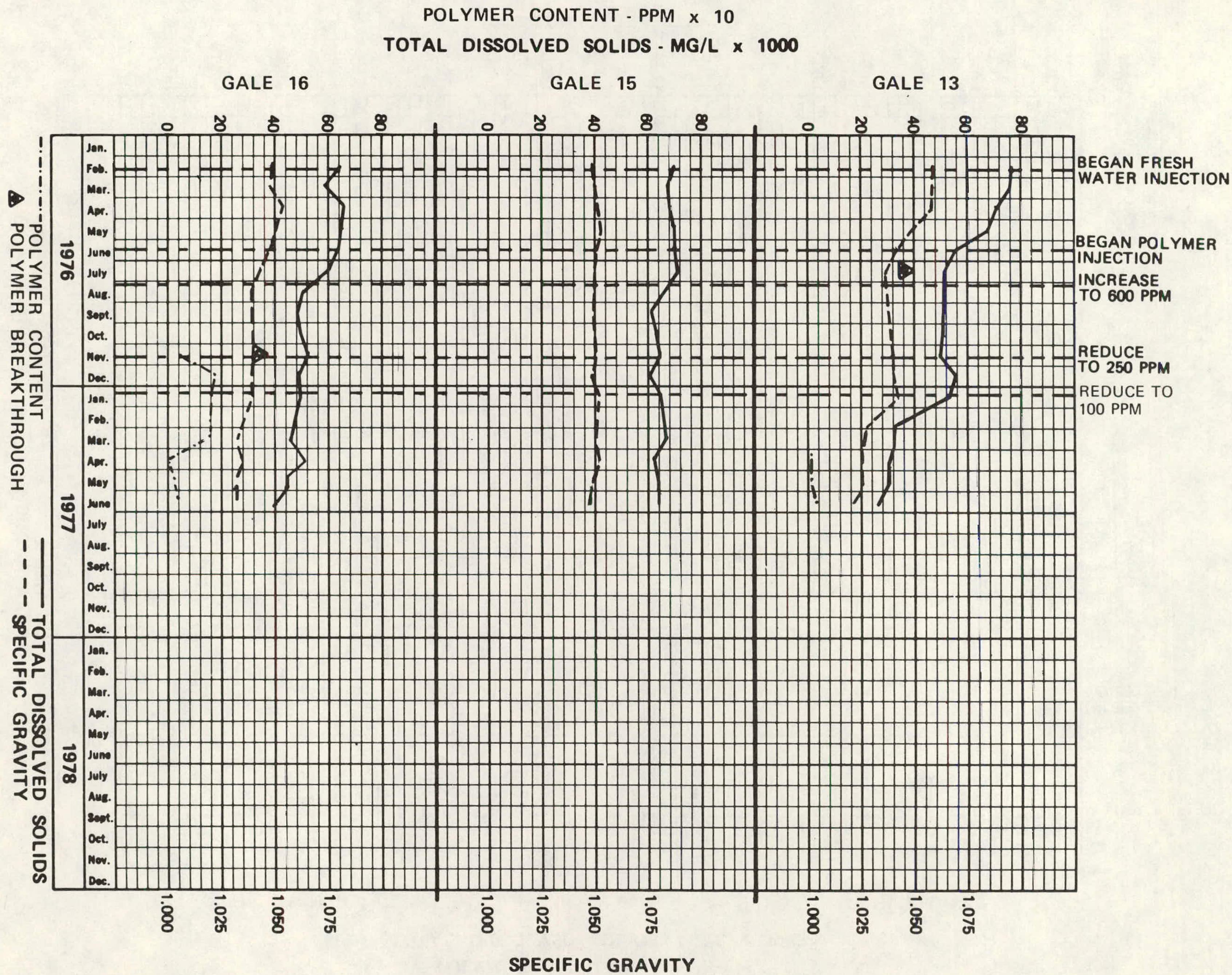
PRODUCED WATER - TOTAL DISSOLVED SOLIDS



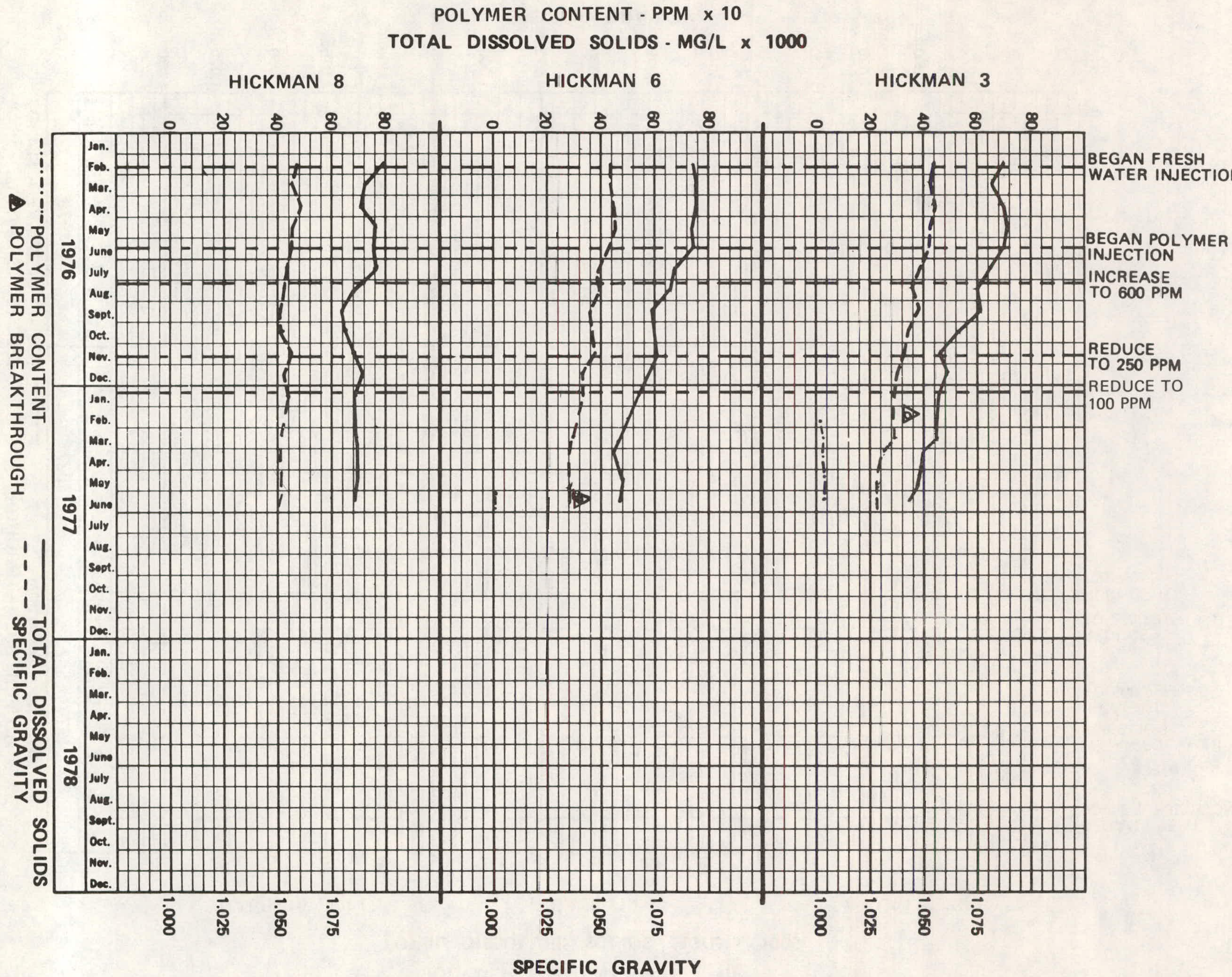
PRODUCED WATER - TOTAL DISSOLVED SOLIDS



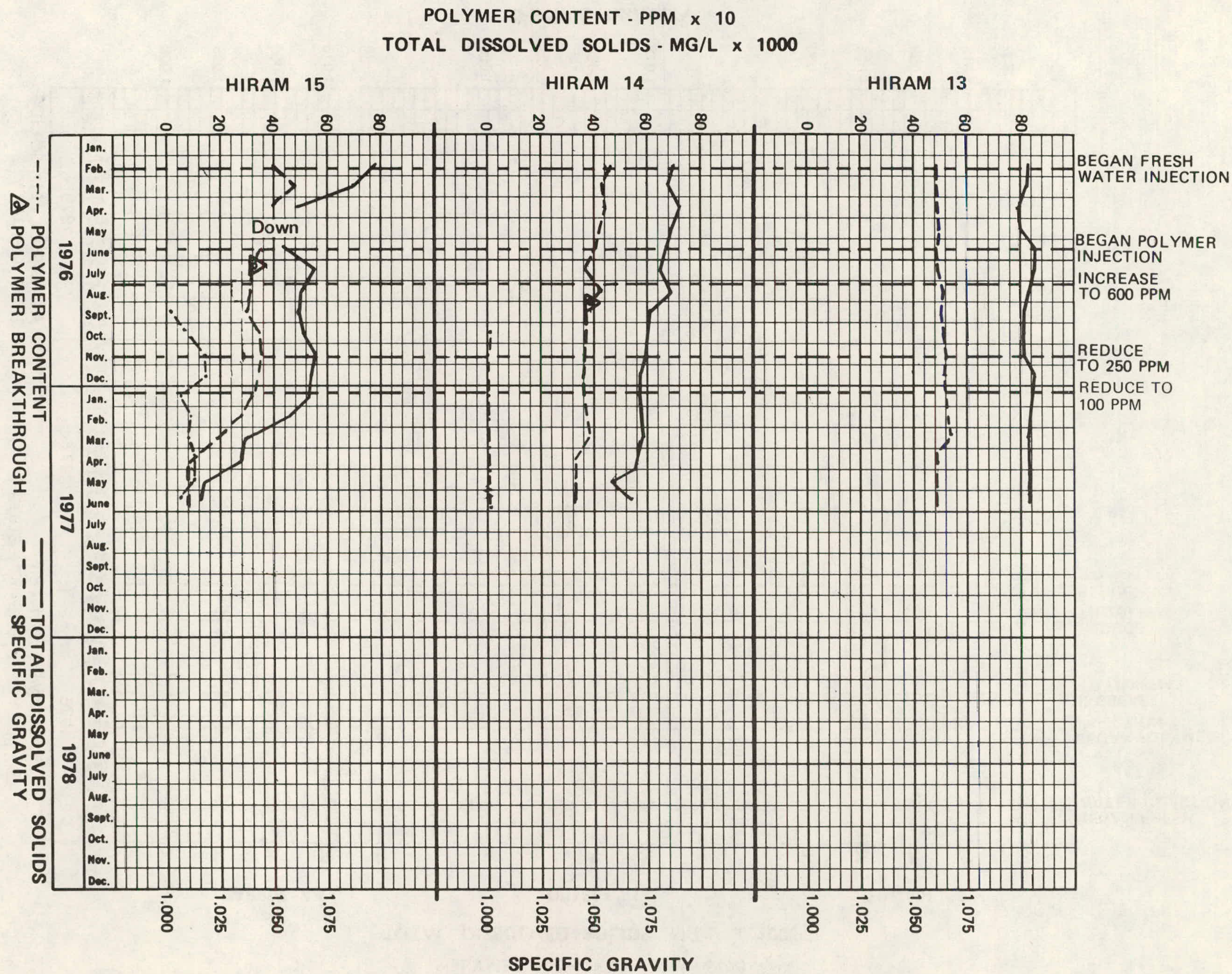
PRODUCED WATER - TOTAL DISSOLVED SOLIDS



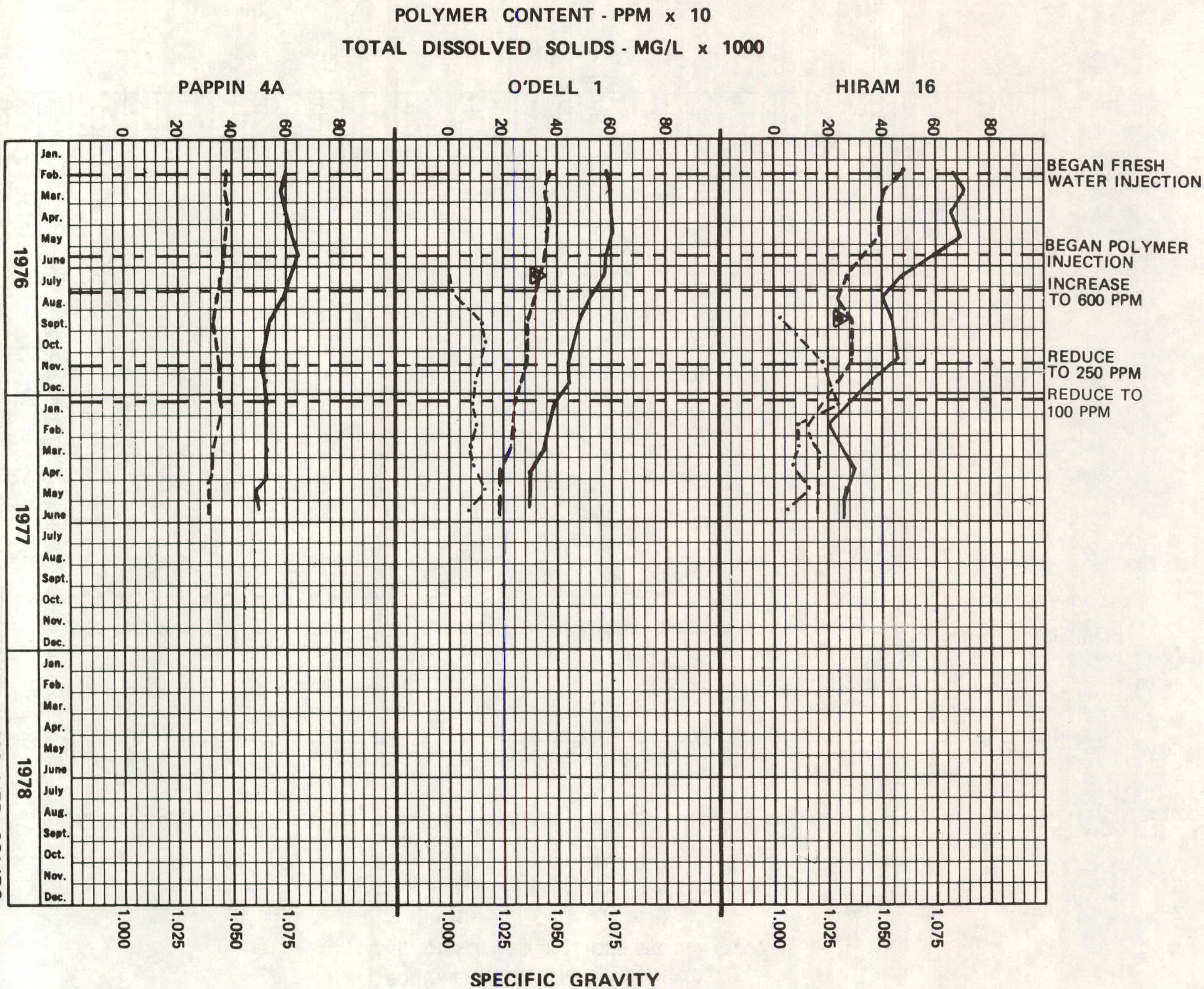
PRODUCED WATER - TOTAL DISSOLVED SOLIDS



PRODUCED WATER - TOTAL DISSOLVED SOLIDS

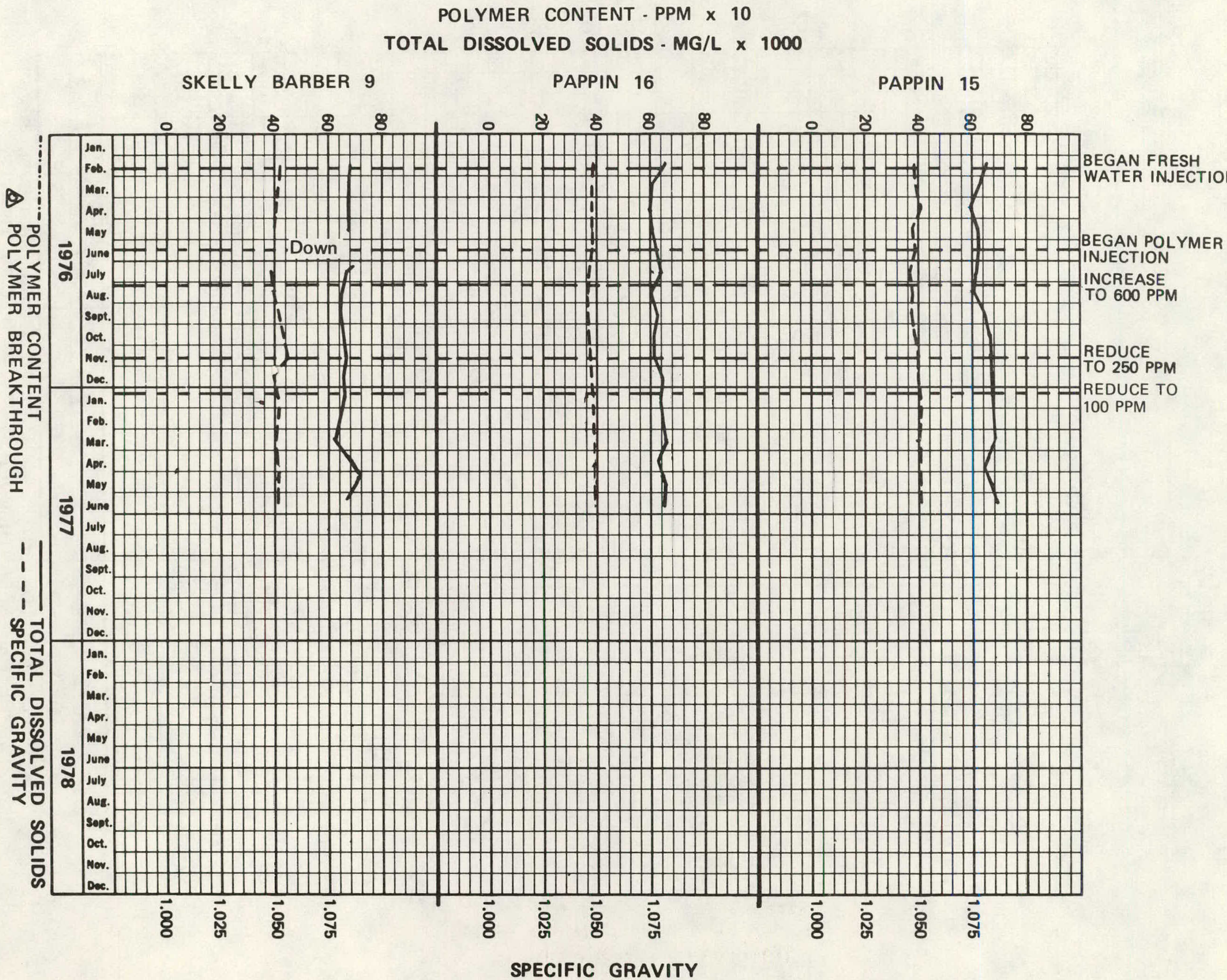


PRODUCED WATER - TOTAL DISSOLVED SOLIDS

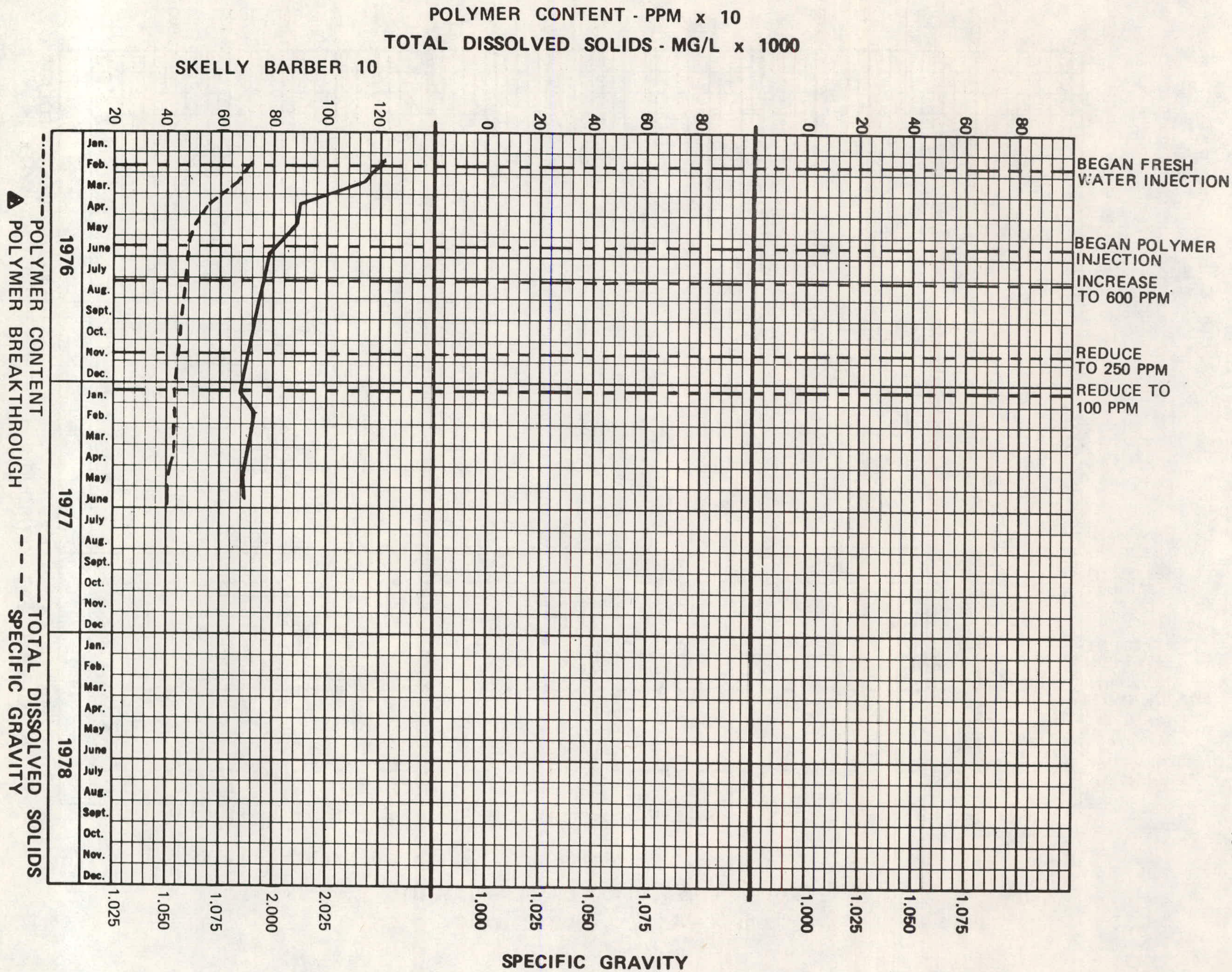


-·-·-·- POLYMER CONTENT
▲ POLYMER BREAKTHROUGH
——— TOTAL DISSOLVED SOLIDS
- - - - SPECIFIC GRAVITY

PRODUCED WATER - TOTAL DISSOLVED SOLIDS

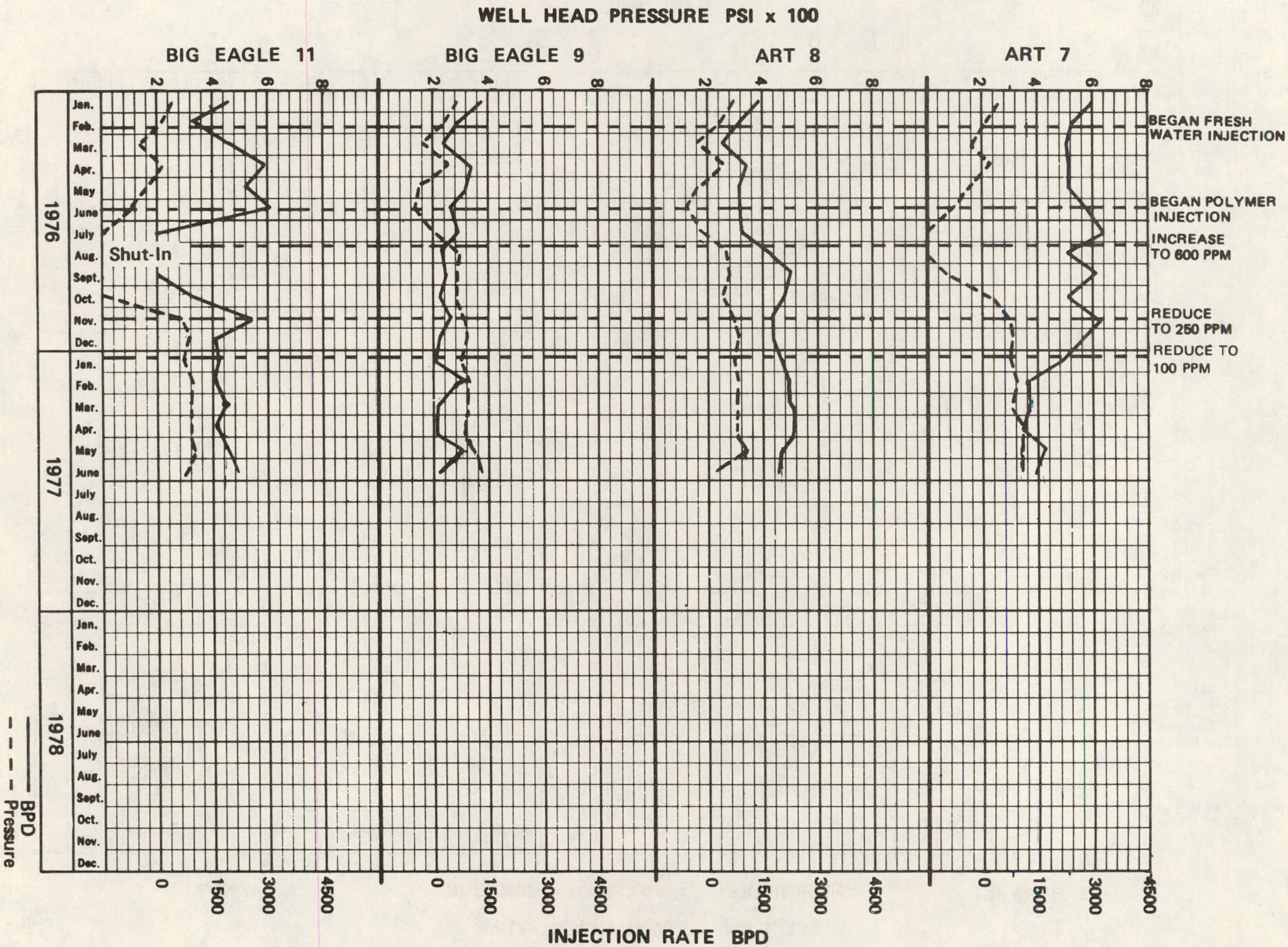


PRODUCED WATER - TOTAL DISSOLVED SOLIDS



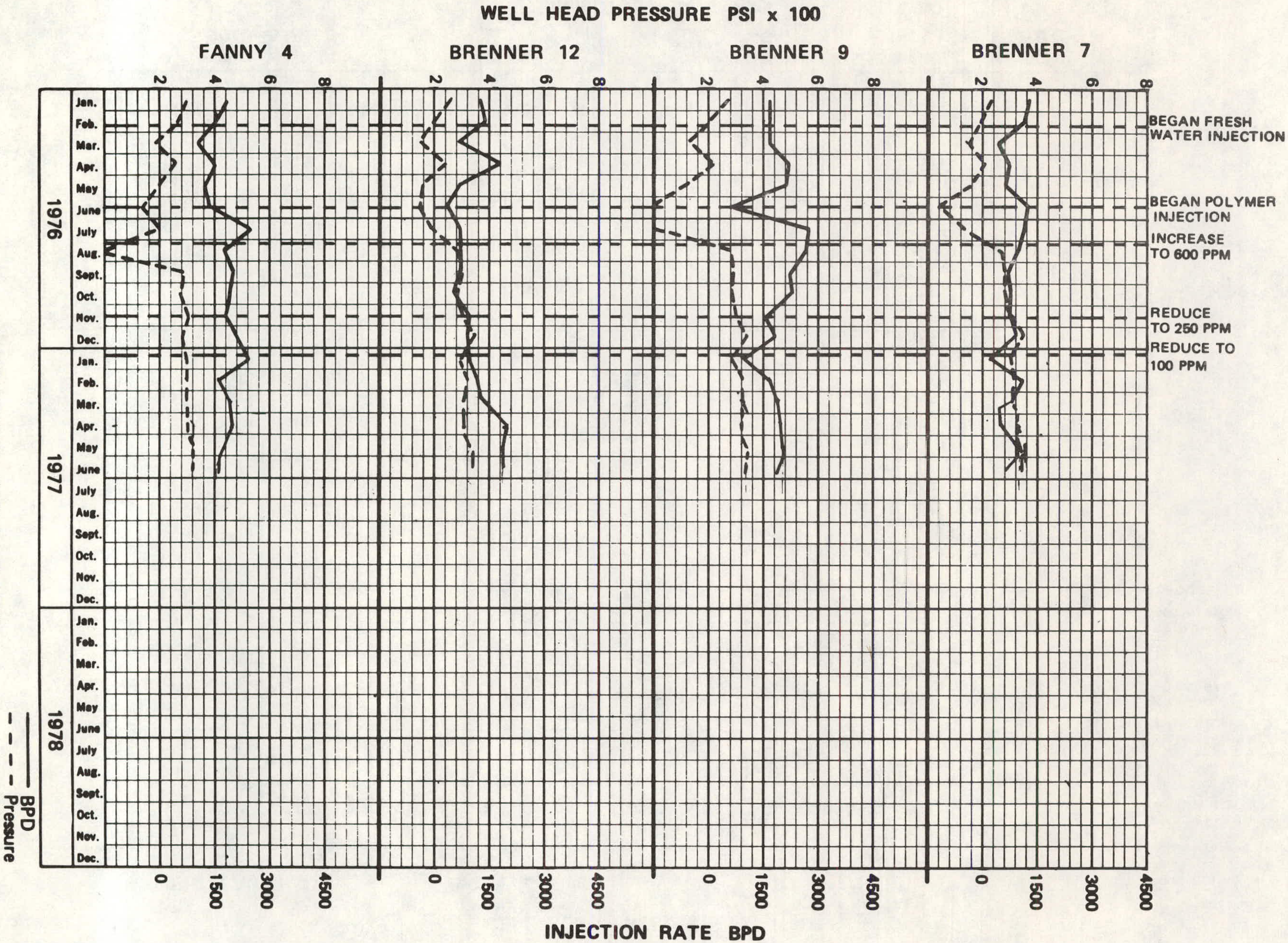
PRODUCED WATER - TOTAL DISSOLVED SOLIDS

10 of 10

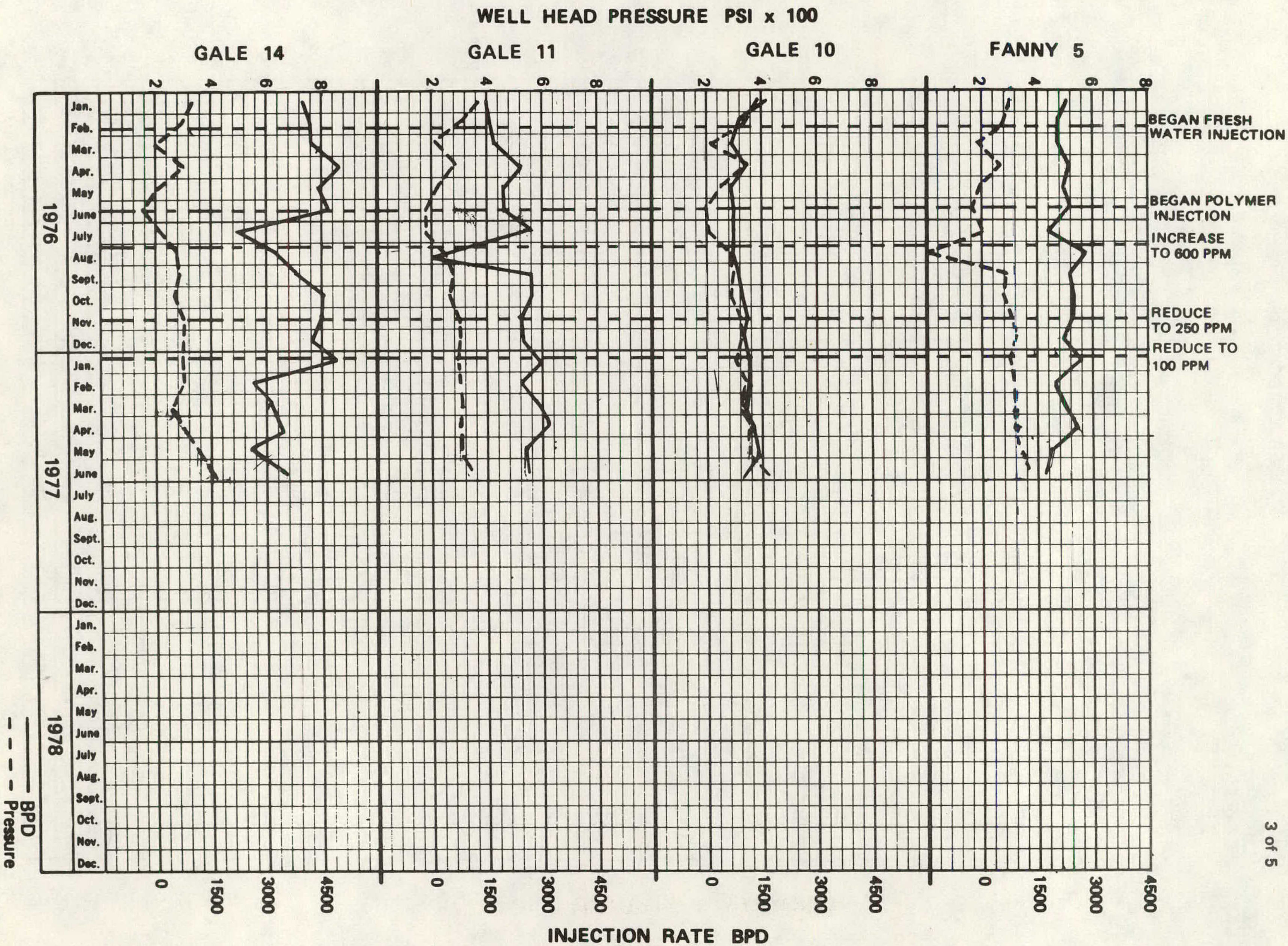


INJECTION WELL DATA

1 of 5

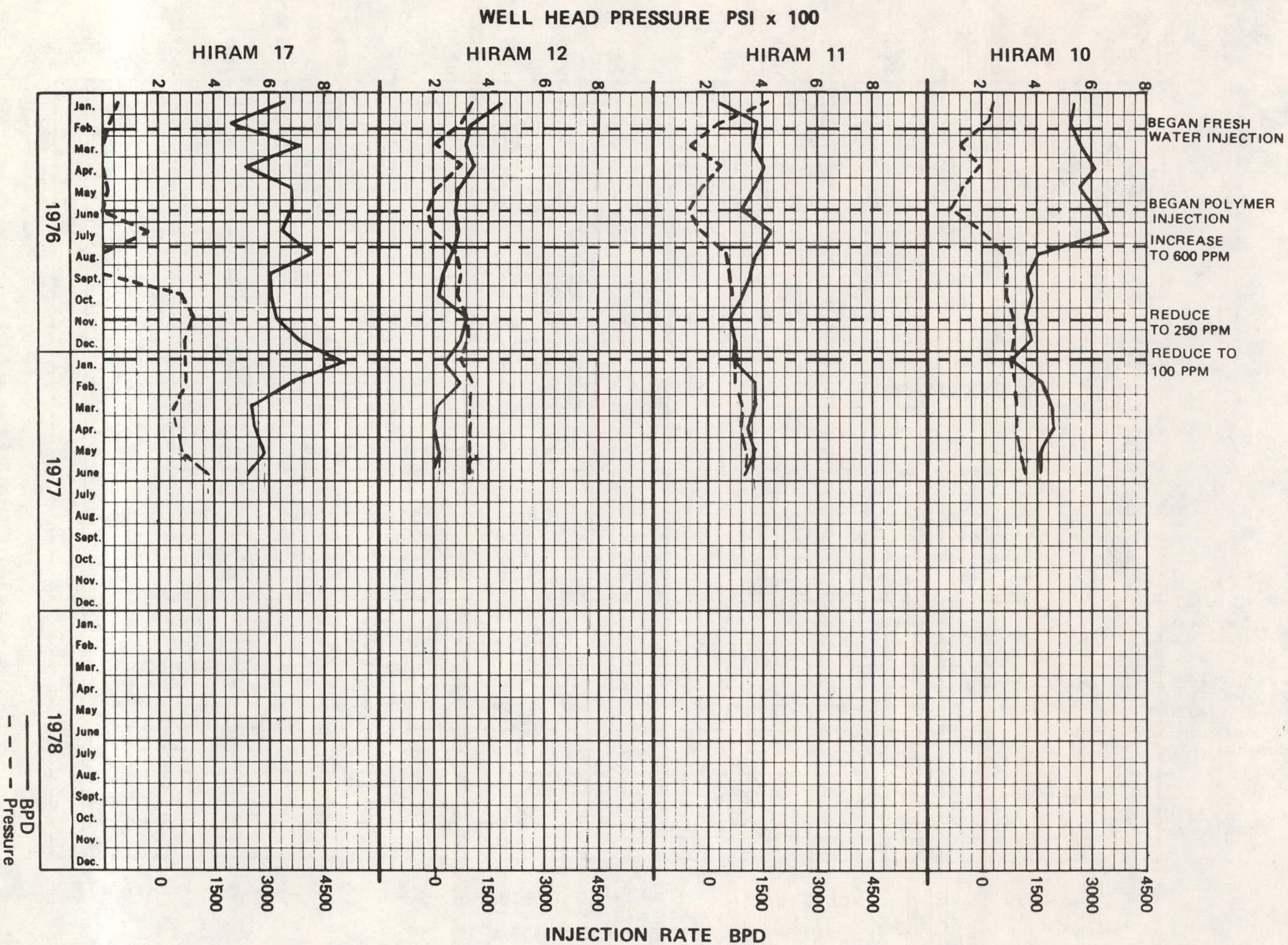


INJECTION WELL DATA

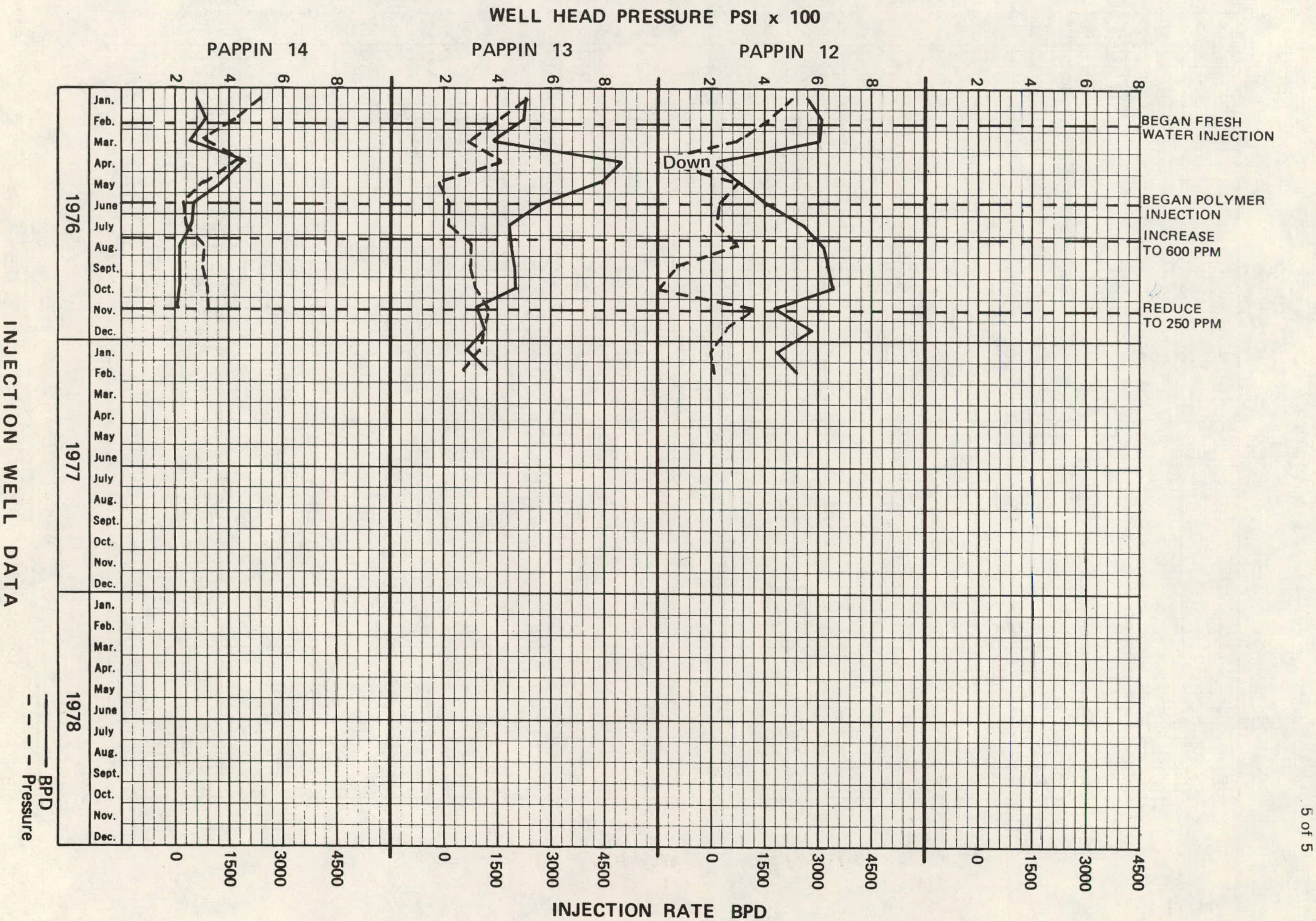


INJECTION WELL DATA

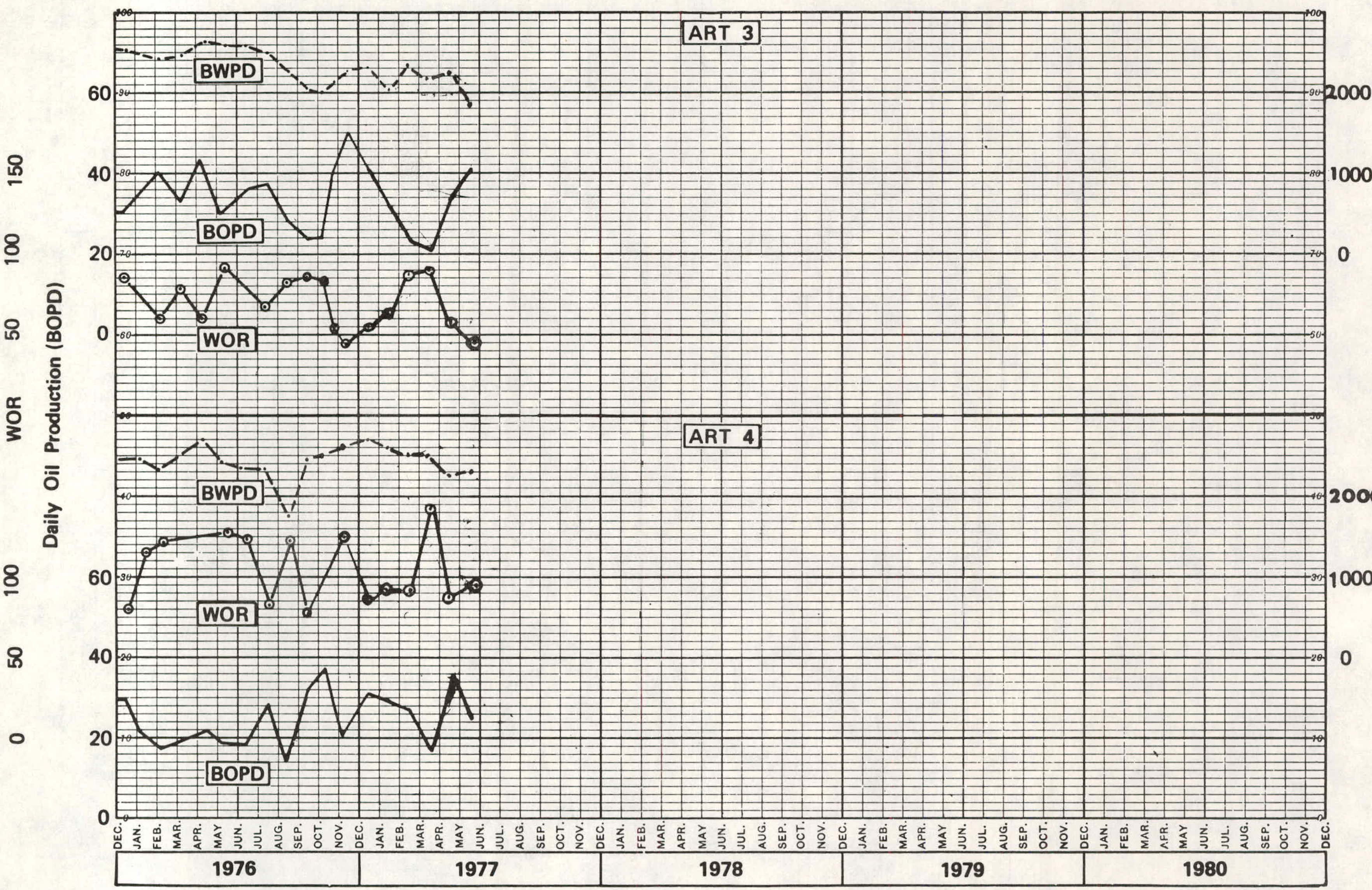
3 of 5

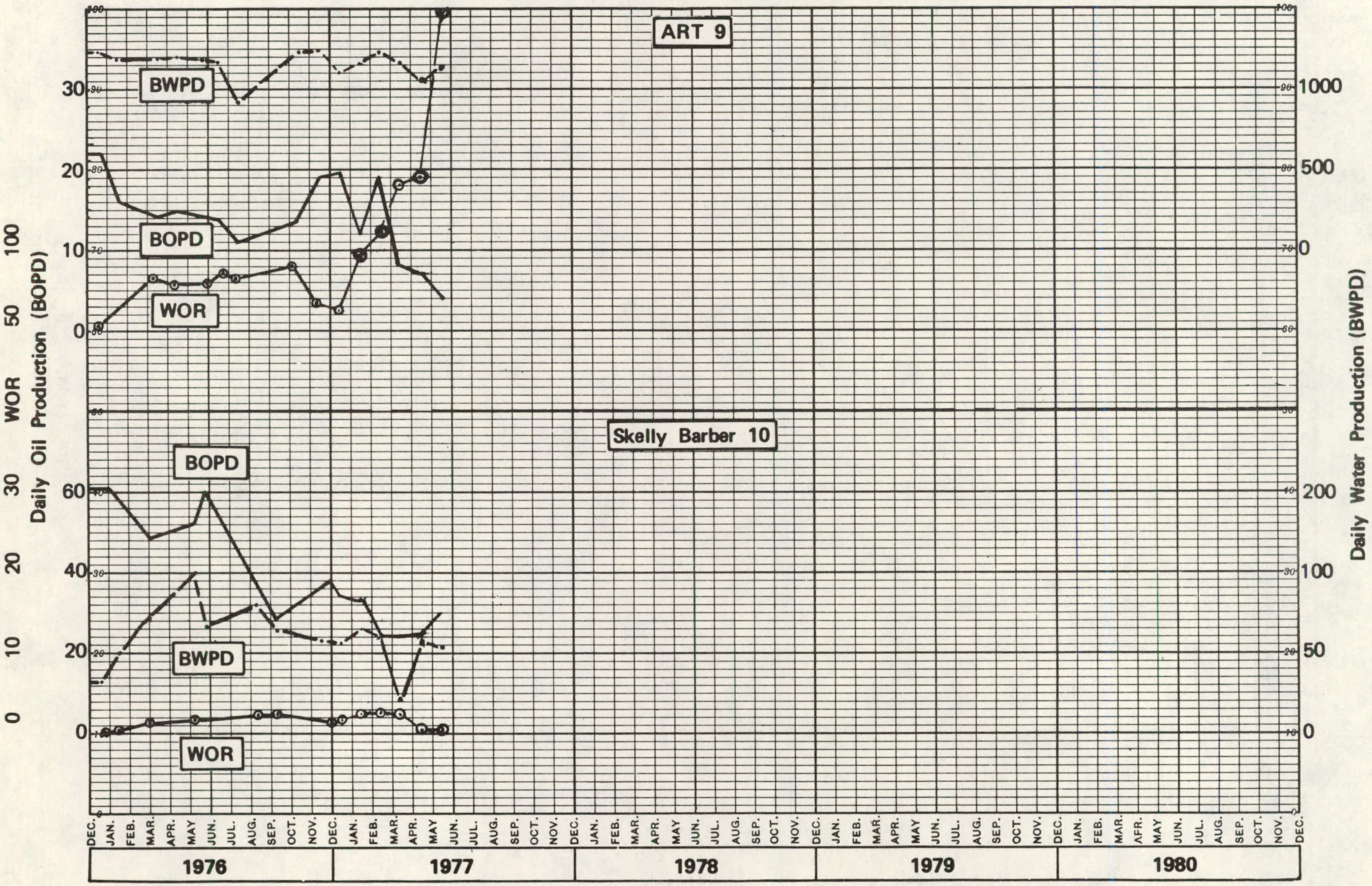


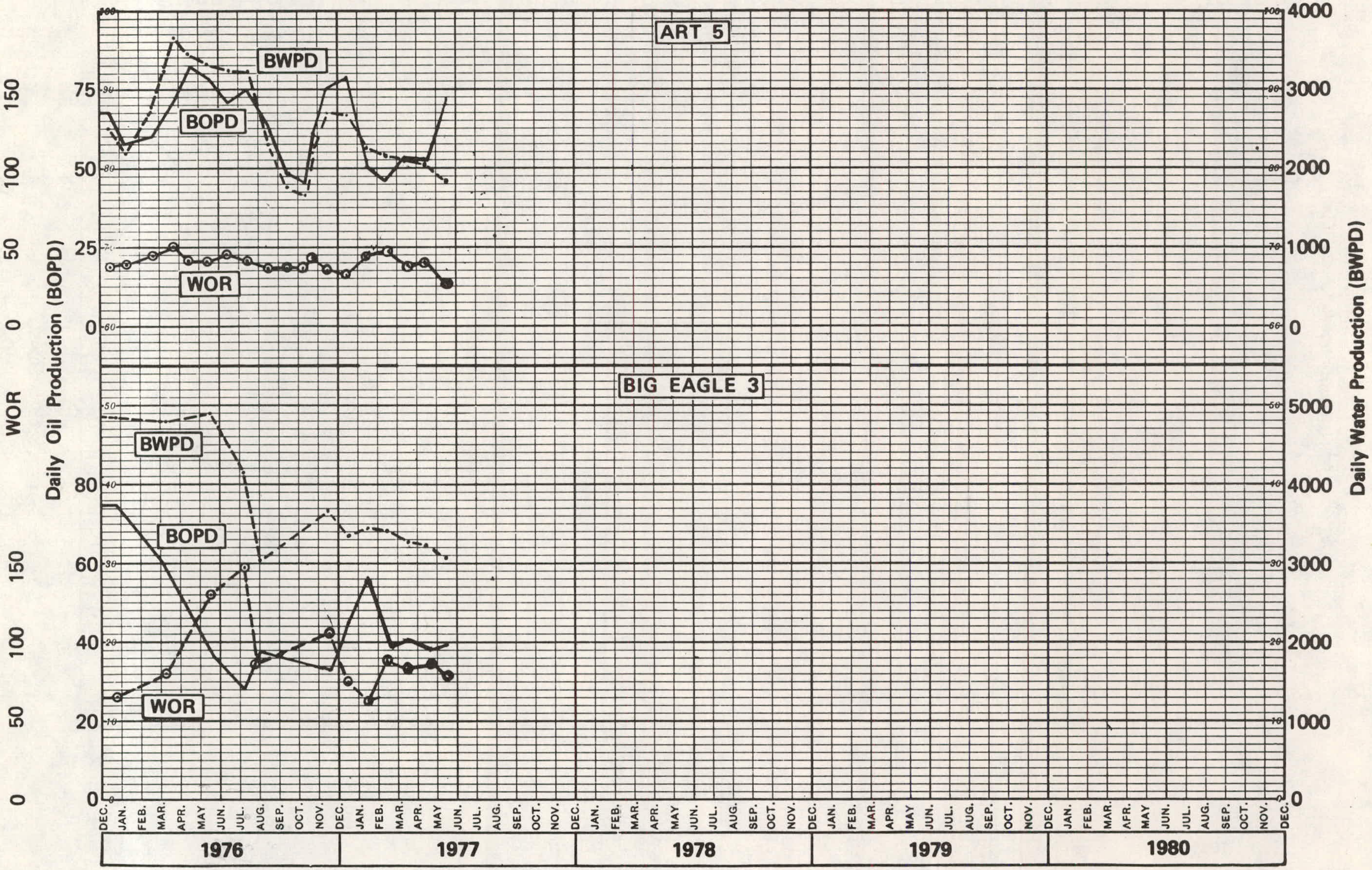
INJECTION WELL DATA

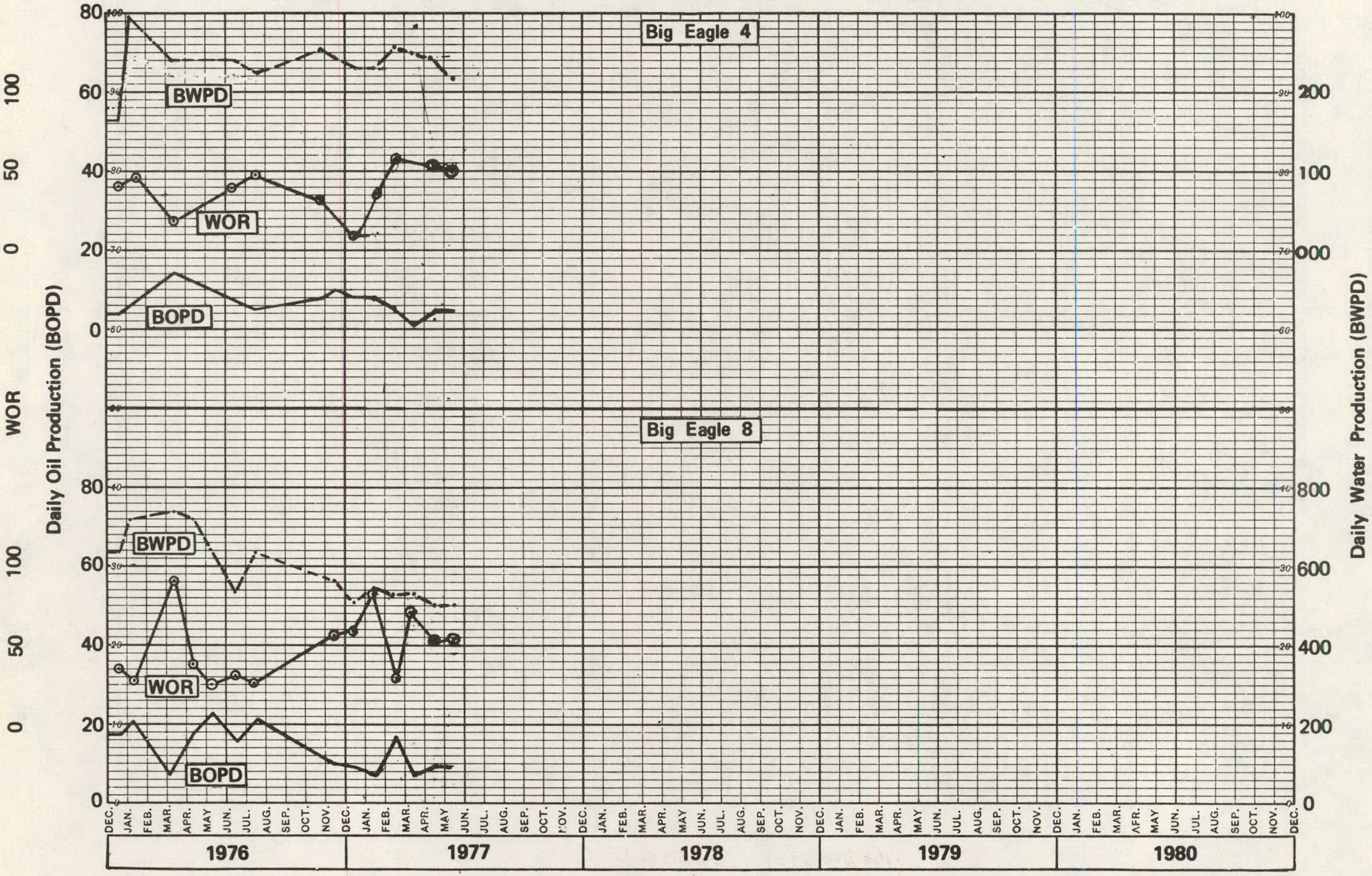


INJECTION WELL DATA


ART 3
BWPD
BOPD
WOR
ART 4
BWPD
WOR
BOPD
WOR
Daily Oil Production (BOPD)
Daily Water Production (BWPD)
0
50
100
150
0
20
40
60
2000
1000
0
DEC.
JAN.
FEB.
MAR.
APR.
MAY
JUN.
JUL.
AUG.
SEP.
OCT.
NOV.
1976
1977
1978
1979
1980

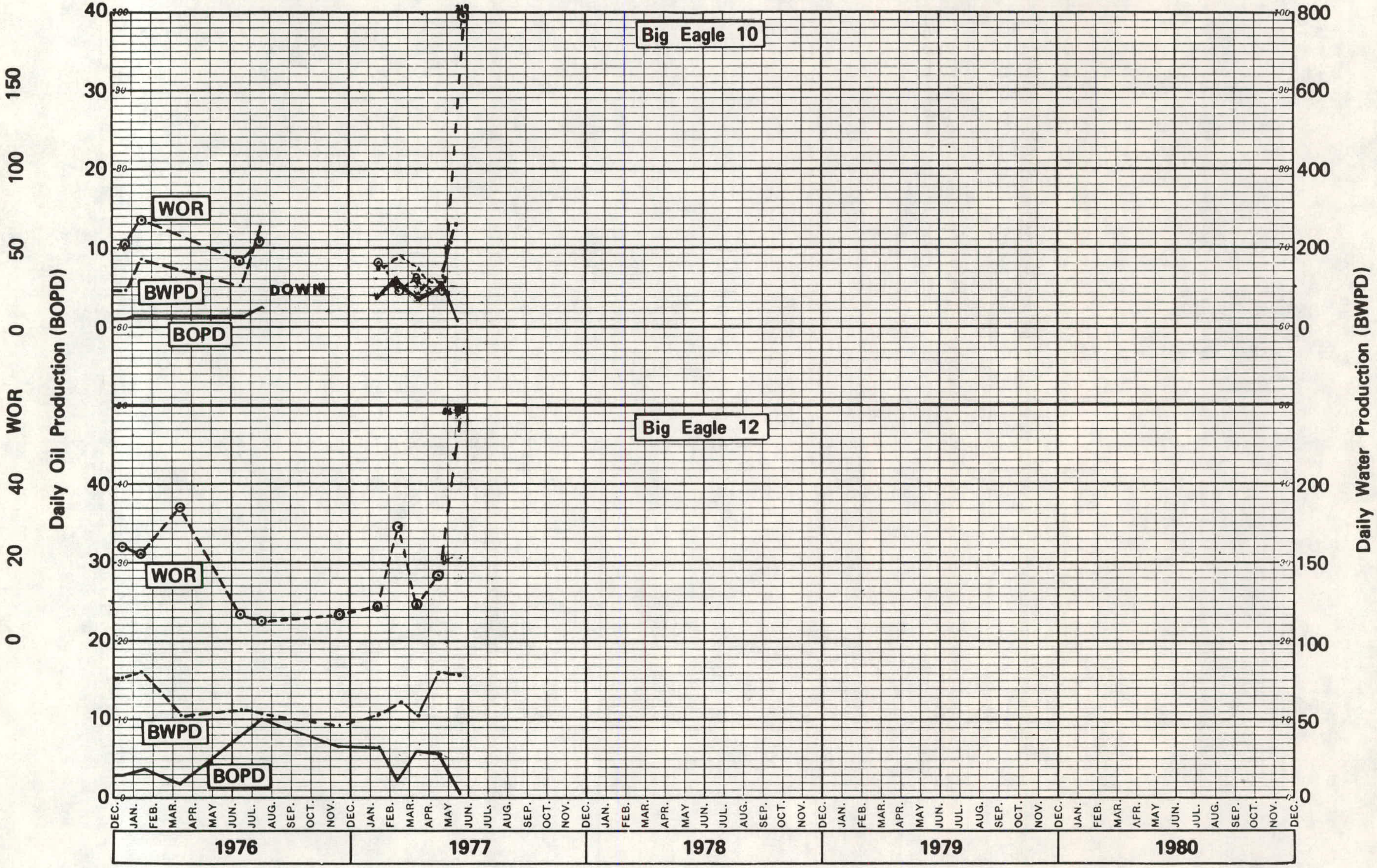

ART 9
BWPD
BOPD
WOR
Skelly Barber 10
BOPD
BWPD
WOR
Daily Oil Production (BOPD)
WOR
Daily Water Production (BWPD)
30
20
10
0
1000
500
0
60
40
20
0
200
100
50
0
100
50
0
30
20
10
0
DEC. JAN. FEB. MAR. APR. MAY JUN. JUL. AUG. SEP. OCT. NOV. DEC.
1976
1977
1978
1979
1980

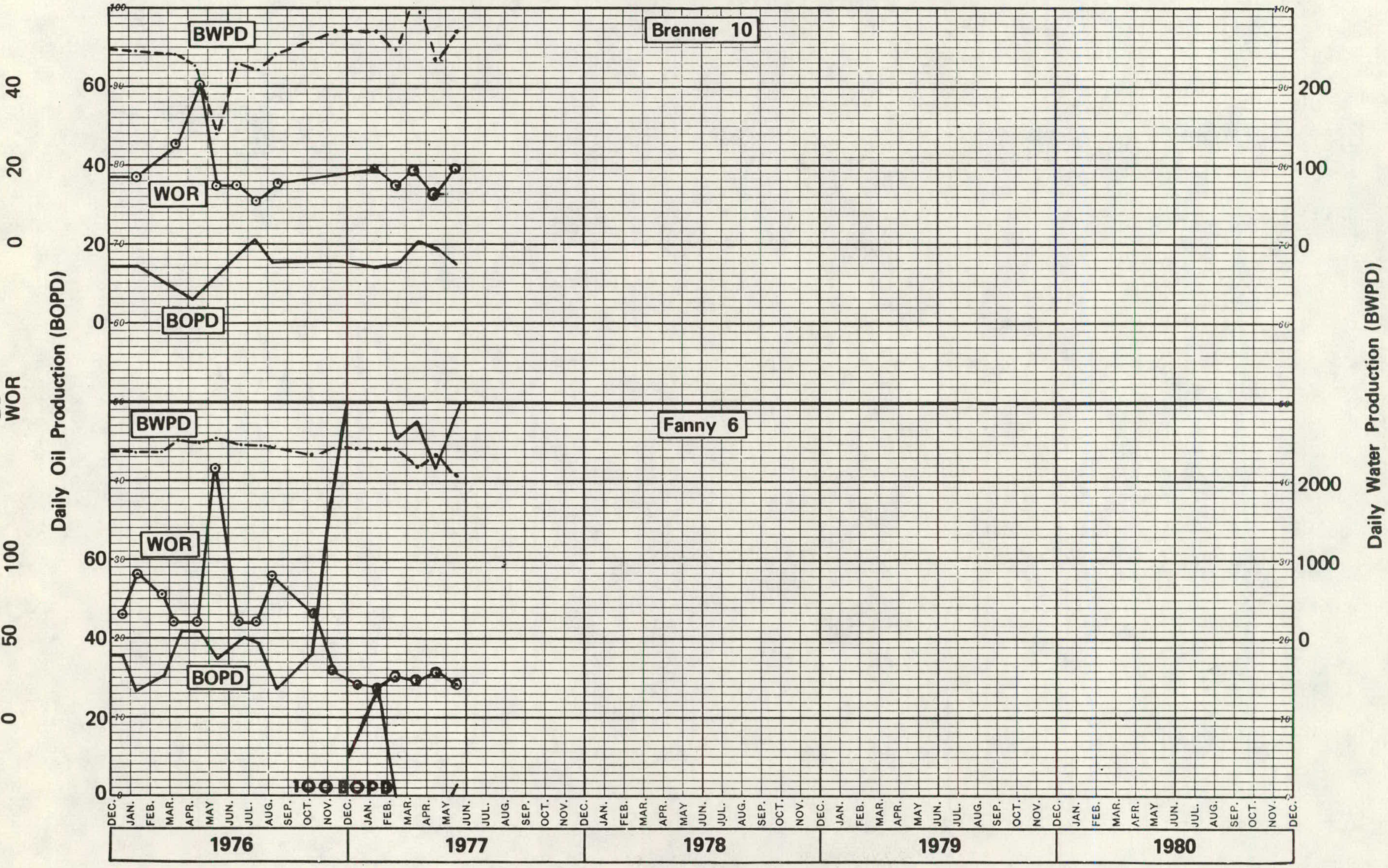

ART 5
BWPD
BOPD
WOR
BIG EAGLE 3
BWPD
BOPD
WOR
WOR
Daily Oil Production (BOPD)
Daily Water Production (BWPD)
150
100
50
0
75
50
25
0
80
60
40
20
4000
3000
2000
1000
5000
DEC. JAN. FEB. MAR. APR. MAY JUN. JUL. AUG. SEP. OCT. NOV.
1976
1977
1978
1979
1980

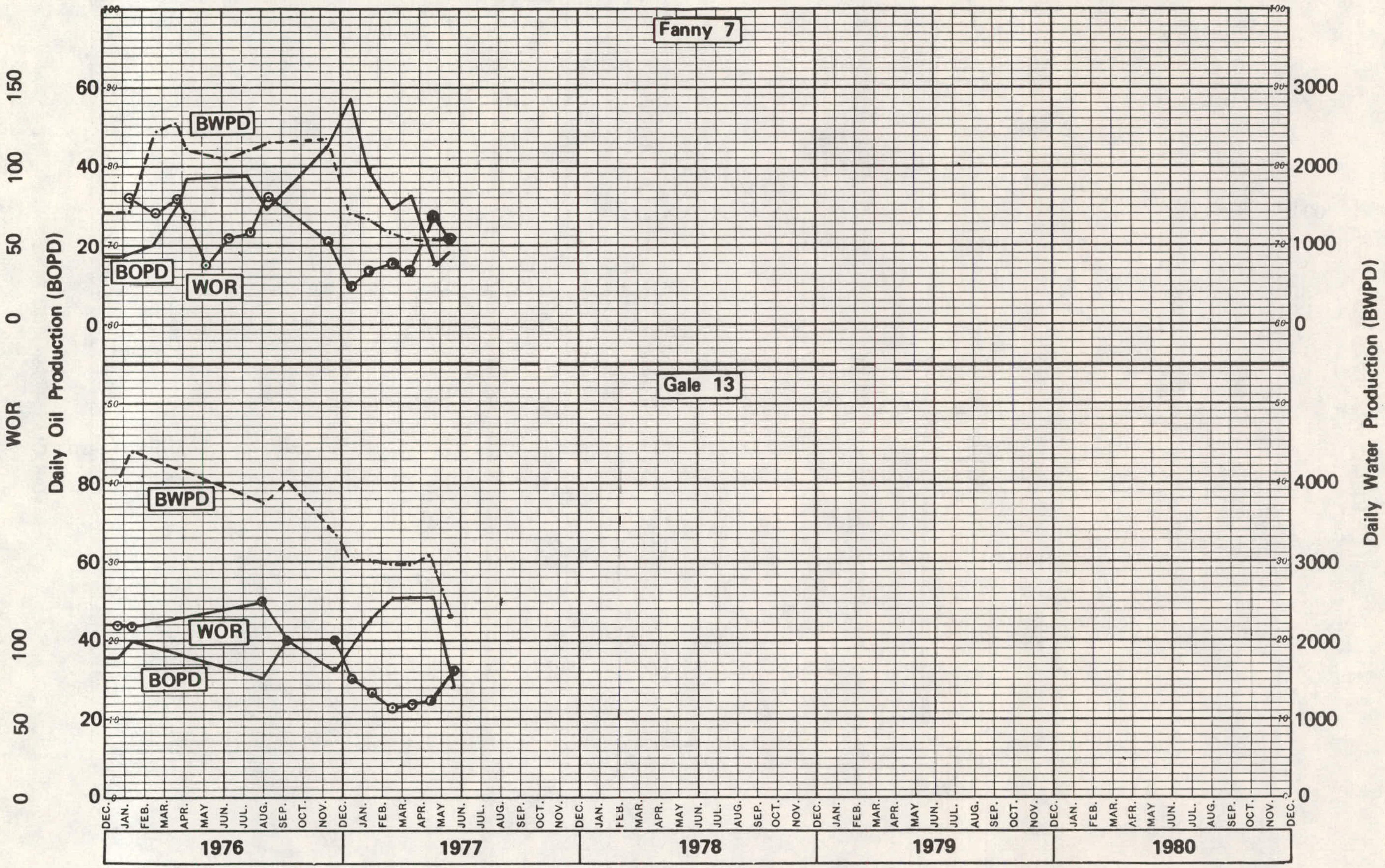


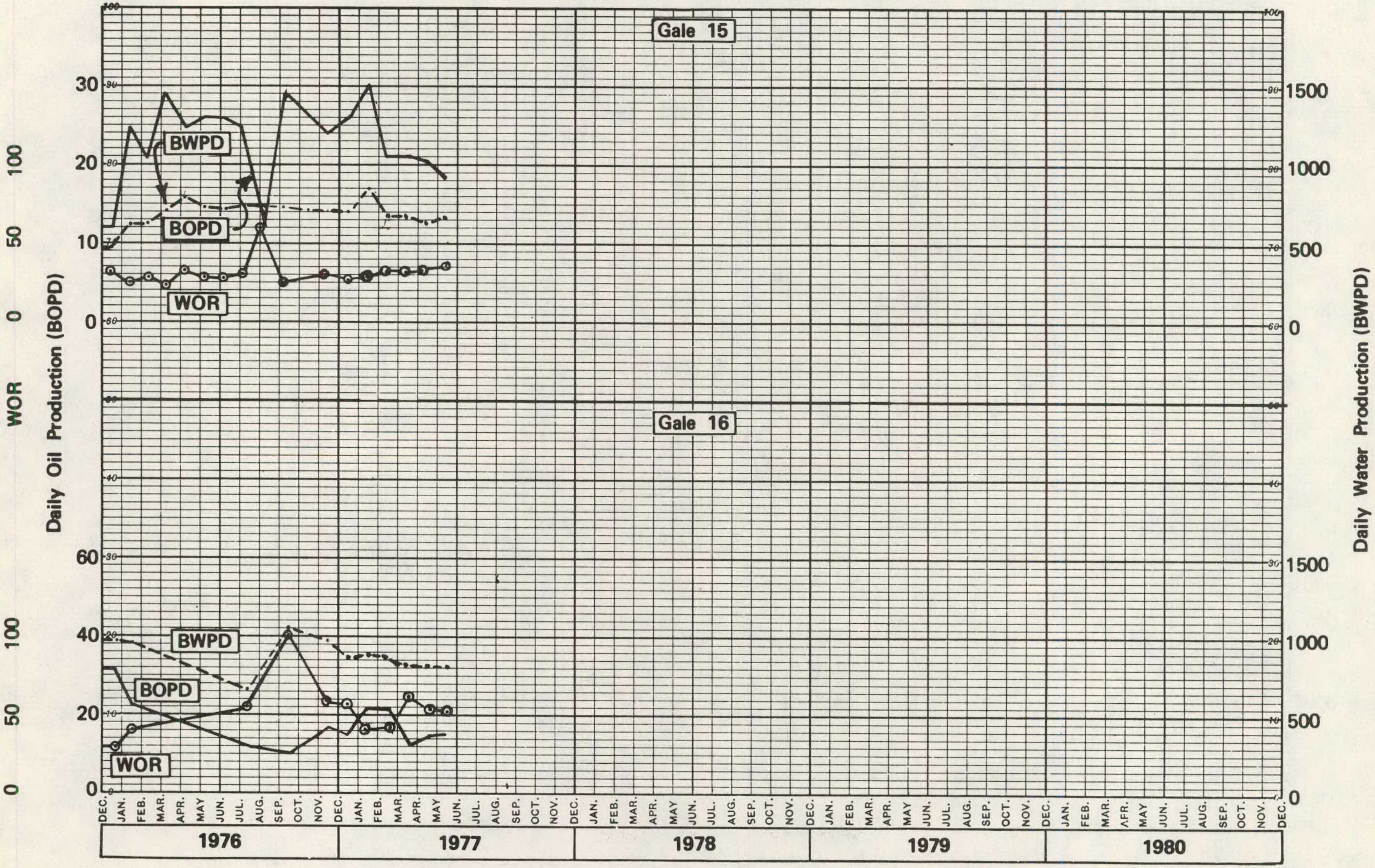
Big Eagle 4
BWPD
WOR
BOPD
Big Eagle 8
BWPD
WOR
BOPD
Daily Oil Production (BOPD)
WOR
Daily Water Production (BWPD)
80
60
40
20
0
100
50
0
200
100
000
800
600
400
200
DEC. JAN. FEB. MAR. APR. MAY JUN. JUL. AUG. SEP. OCT. NOV.
1976
1977
1978
1979
1980

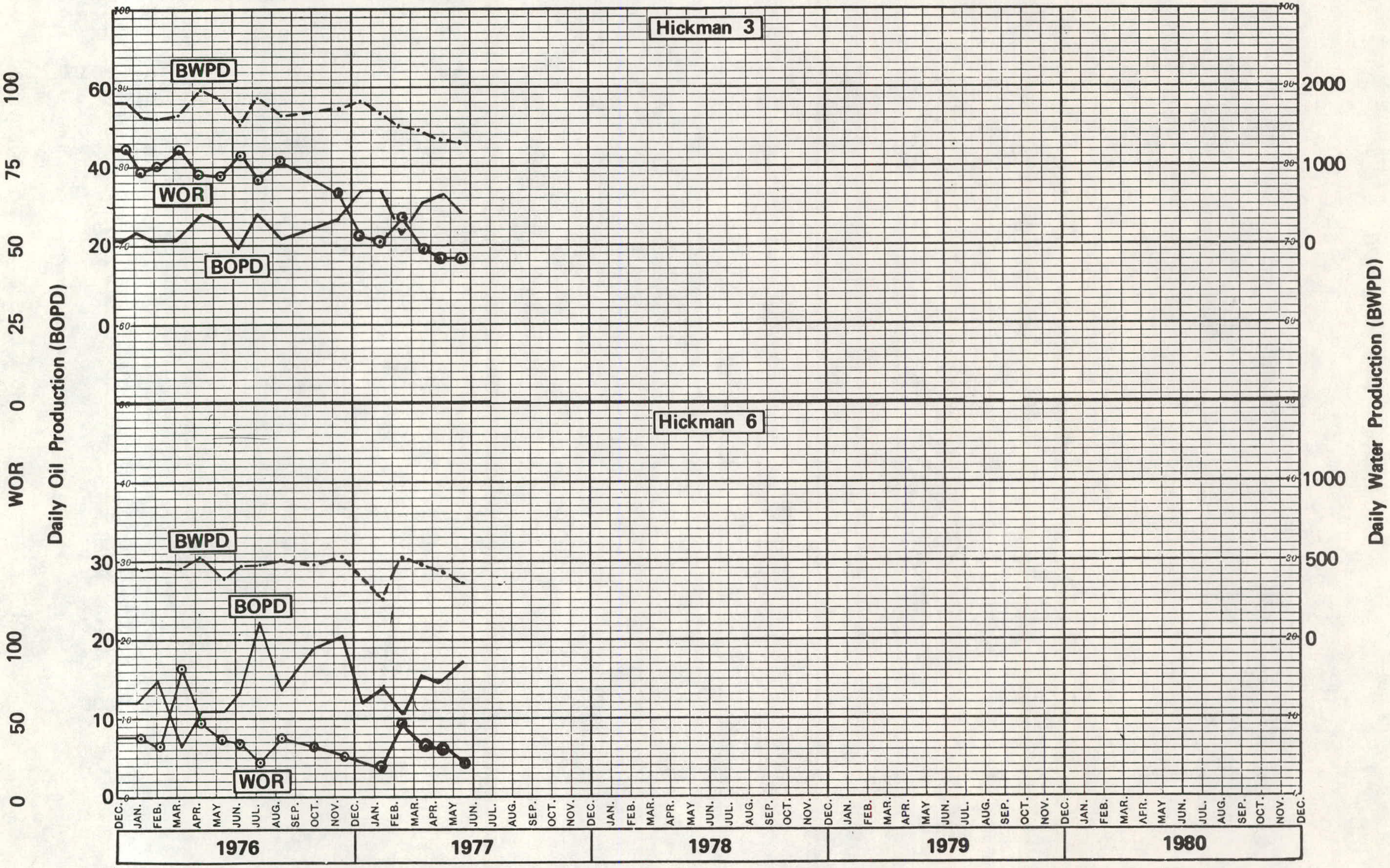
-55-

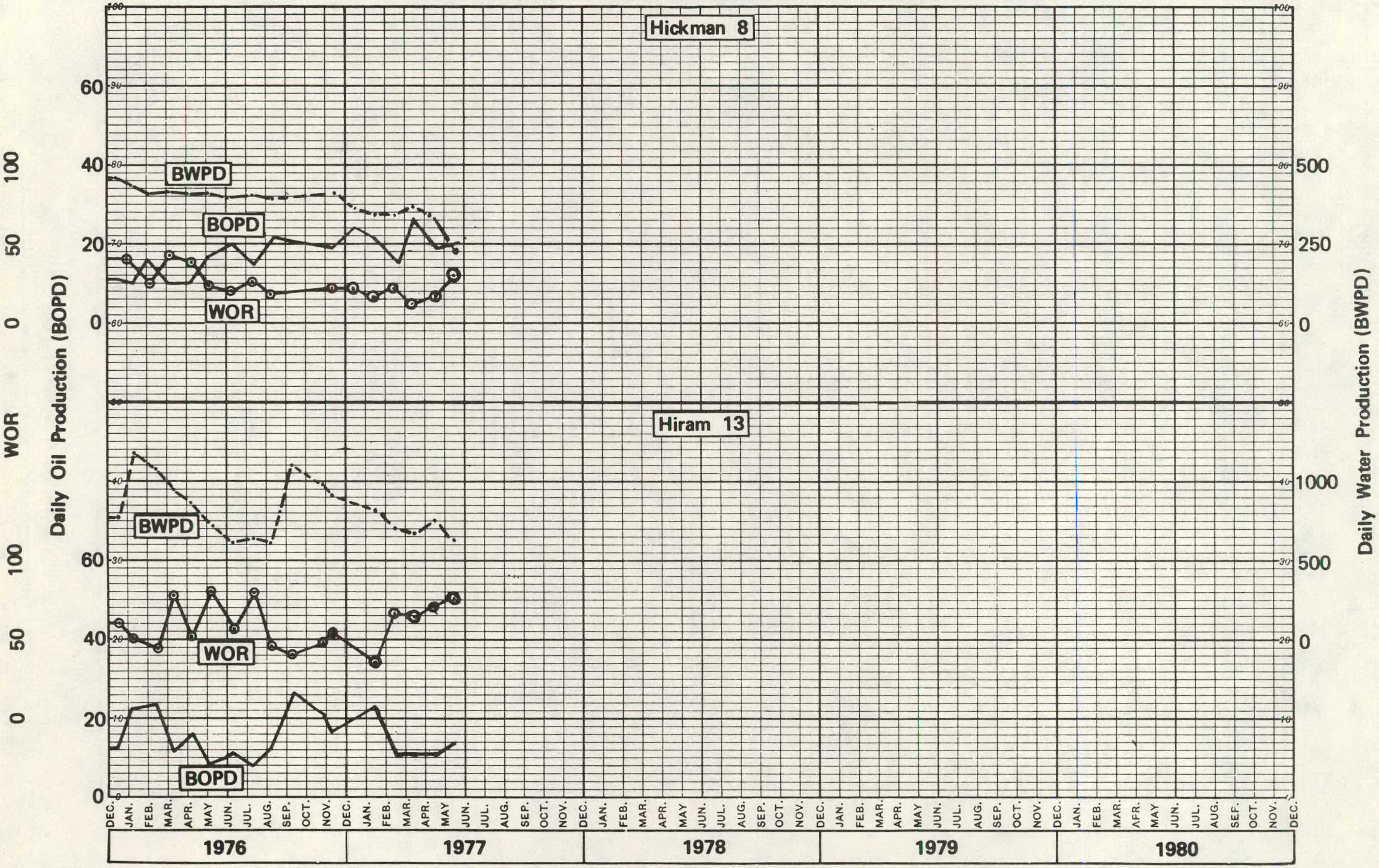

Big Eagle 10
WOR
BWPD
DOWN
BOPD
Big Eagle 12
WOR
BWPD
BOPD
WOR
Daily Oil Production (BOPD)
Daily Water Production (BWPD)
1976
1977
1978
1979
1980

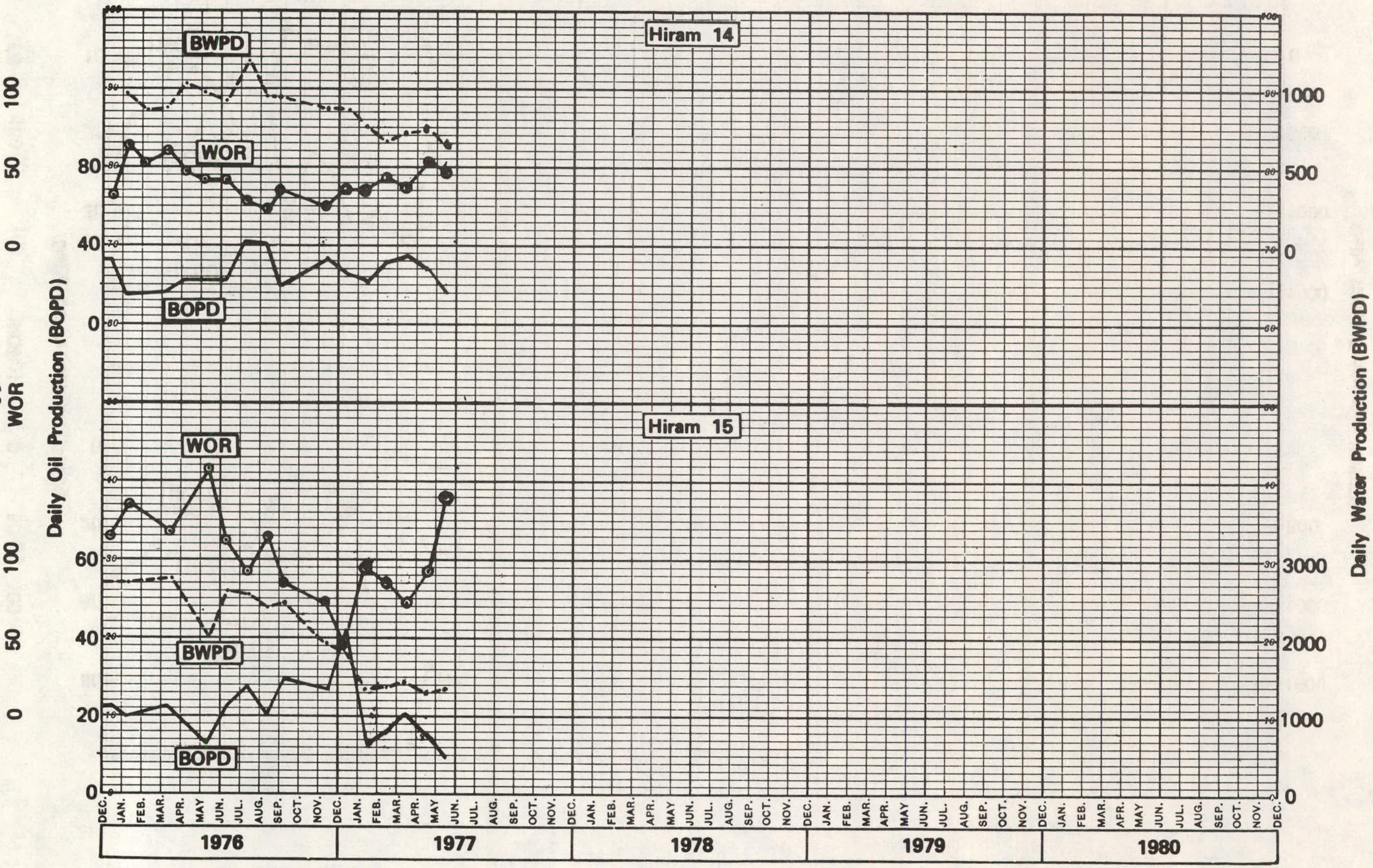

Brenner 10
BWPD
WOR
BOPD
Fanny 6
BWPD
WOR
BOPD
100 BOPD
Daily Oil Production (BOPD)
WOR
Daily Water Production (BWPD)
1976
1977
1978
1979
1980


Fanny 7
Gale 13
BWPD
BOPD
WOR
WOR
Daily Oil Production (BOPD)
Daily Water Production (BWPD)
1976
1977
1978
1979
1980

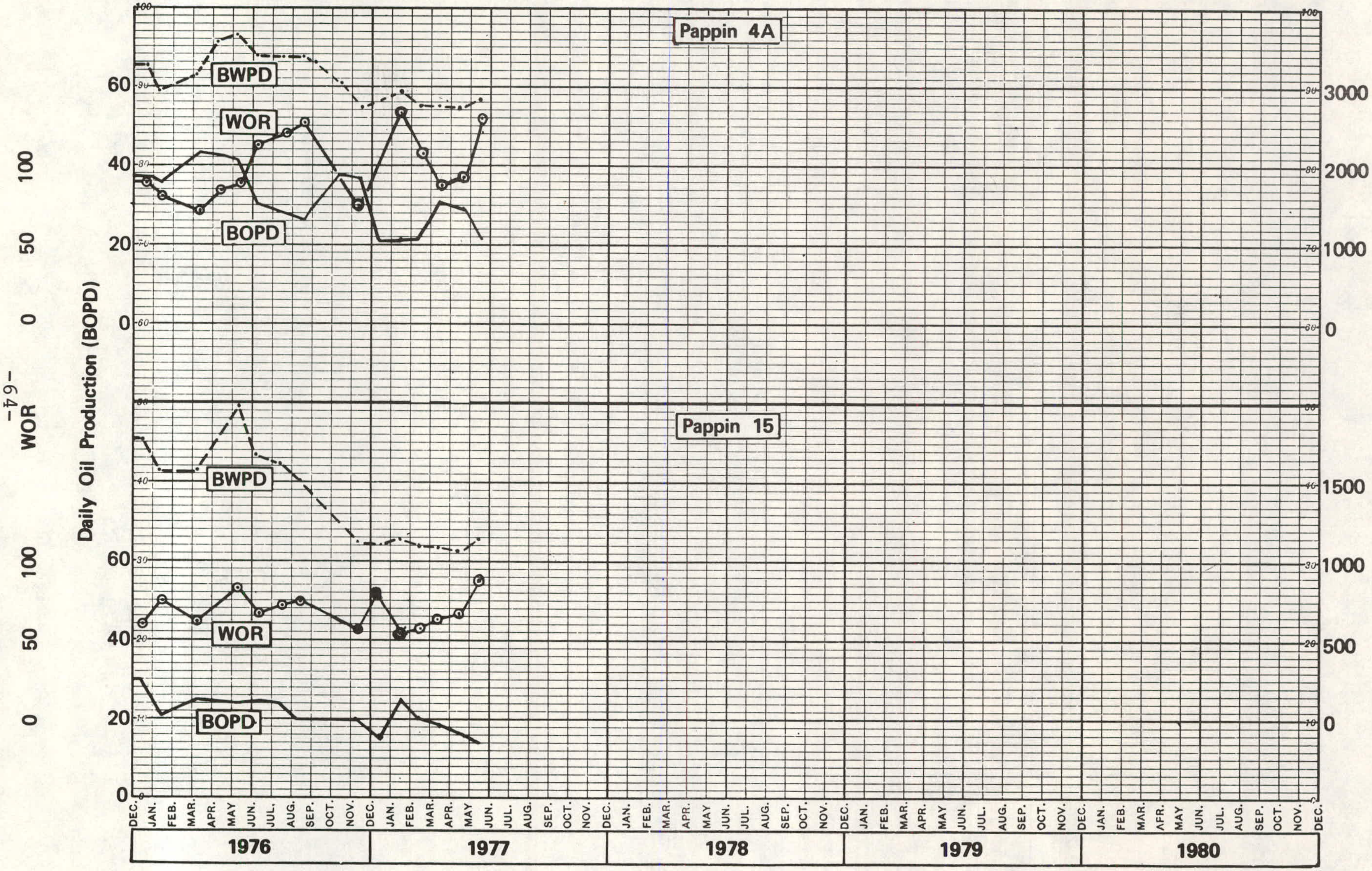

Gale 15
BWPD
BOPD
WOR
Gale 16
BWPD
BOPD
WOR
WOR
Daily Oil Production (BOPD)
Daily Water Production (BWPD)
1976
1977
1978
1979
1980


Hickman 3
BWPD
WOR
BOPD
Hickman 6
BWPD
BOPD
WOR
WOR
Daily Oil Production (BOPD)
Daily Water Production (BWPD)
DEC. JAN. FEB. MAR. APR. MAY JUN. JUL. AUG. SEP. OCT. NOV.
1976
1977
1978
1979
1980

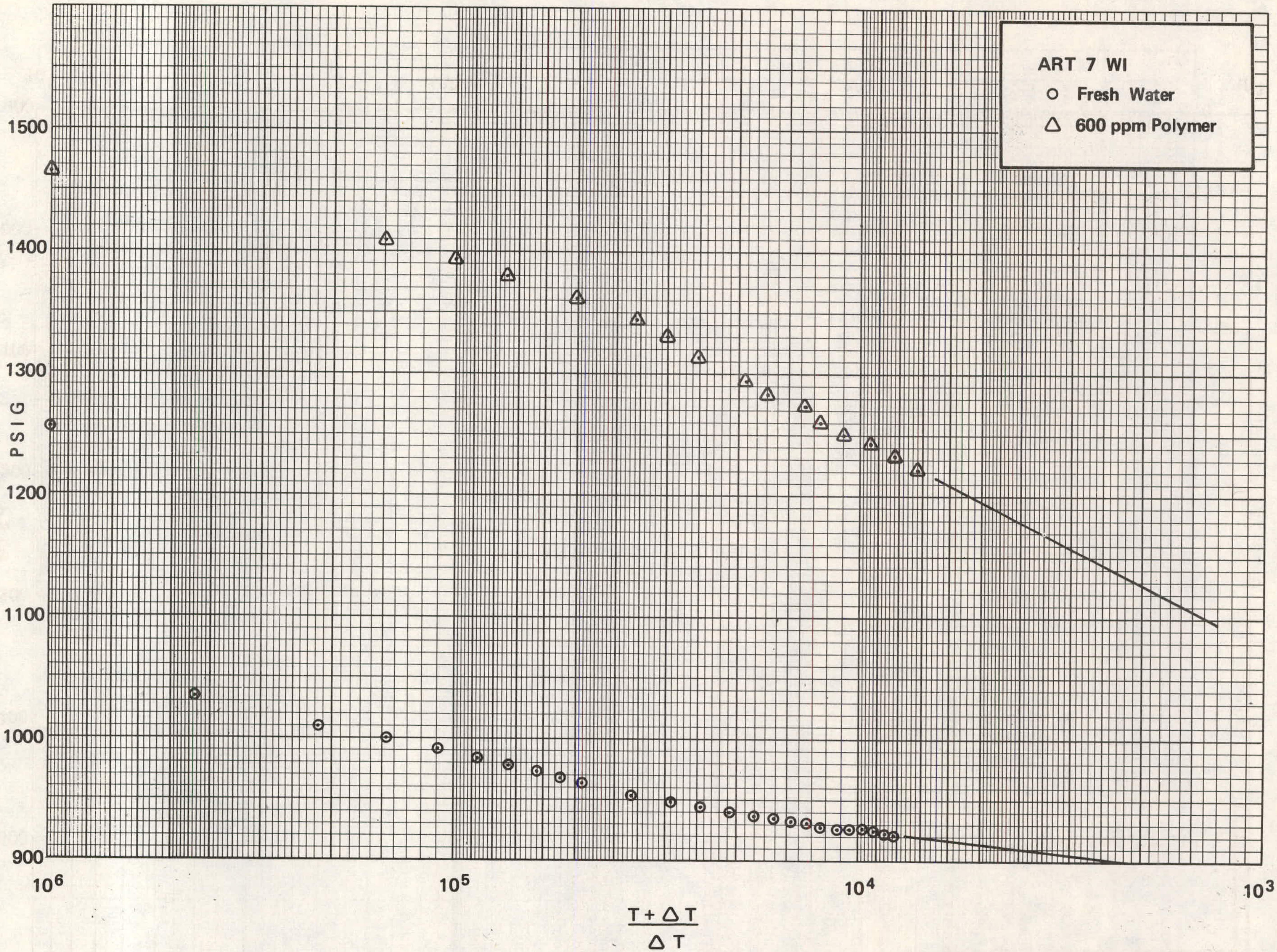

Hickman 8
BWPD
BOPD
WOR
Hiram 13
BWPD
WOR
BOPD
WOR
Daily Oil Production (BOPD)
Daily Water Production (BWPD)
DEC. JAN. FEB. MAR. APR. MAY JUN. JUL. AUG. SEP. OCT. NOV. DEC.
1976
1977
1978
1979
1980

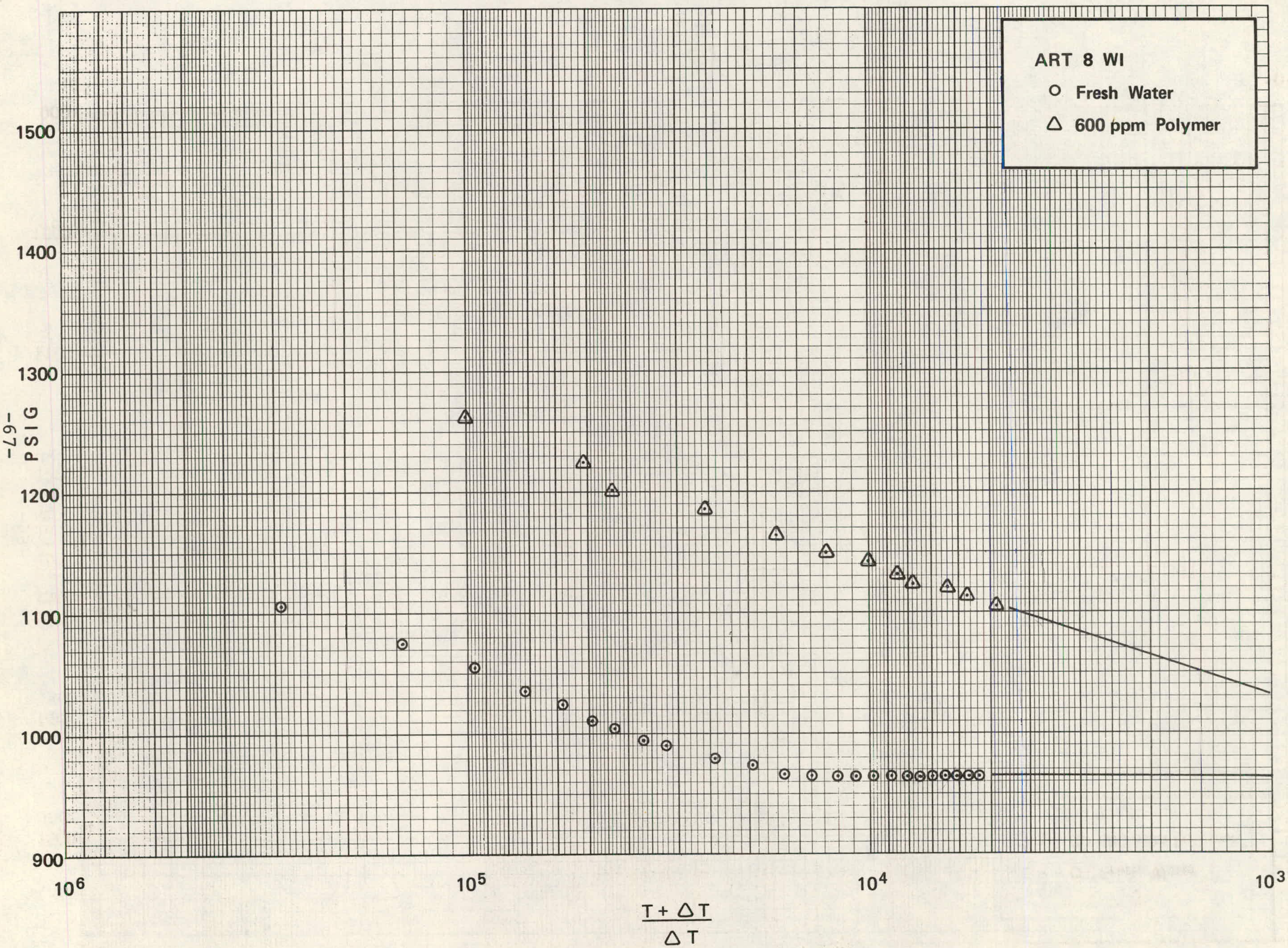

Hiram 14
BWPD
WOR
BOPD
Hiram 15
WOR
BWPD
BOPD
WOR
Daily Oil Production (BOPD)
Daily Water Production (BWPD)
100
50
0
80
40
0
100
50
0
60
40
20
0
1000
500
0
3000
2000
1000
0
DEC. JAN. FEB. MAR. APR. MAY JUN. JUL. AUG. SEP. OCT. NOV. DEC.
1976
1977
1978
1979
1980

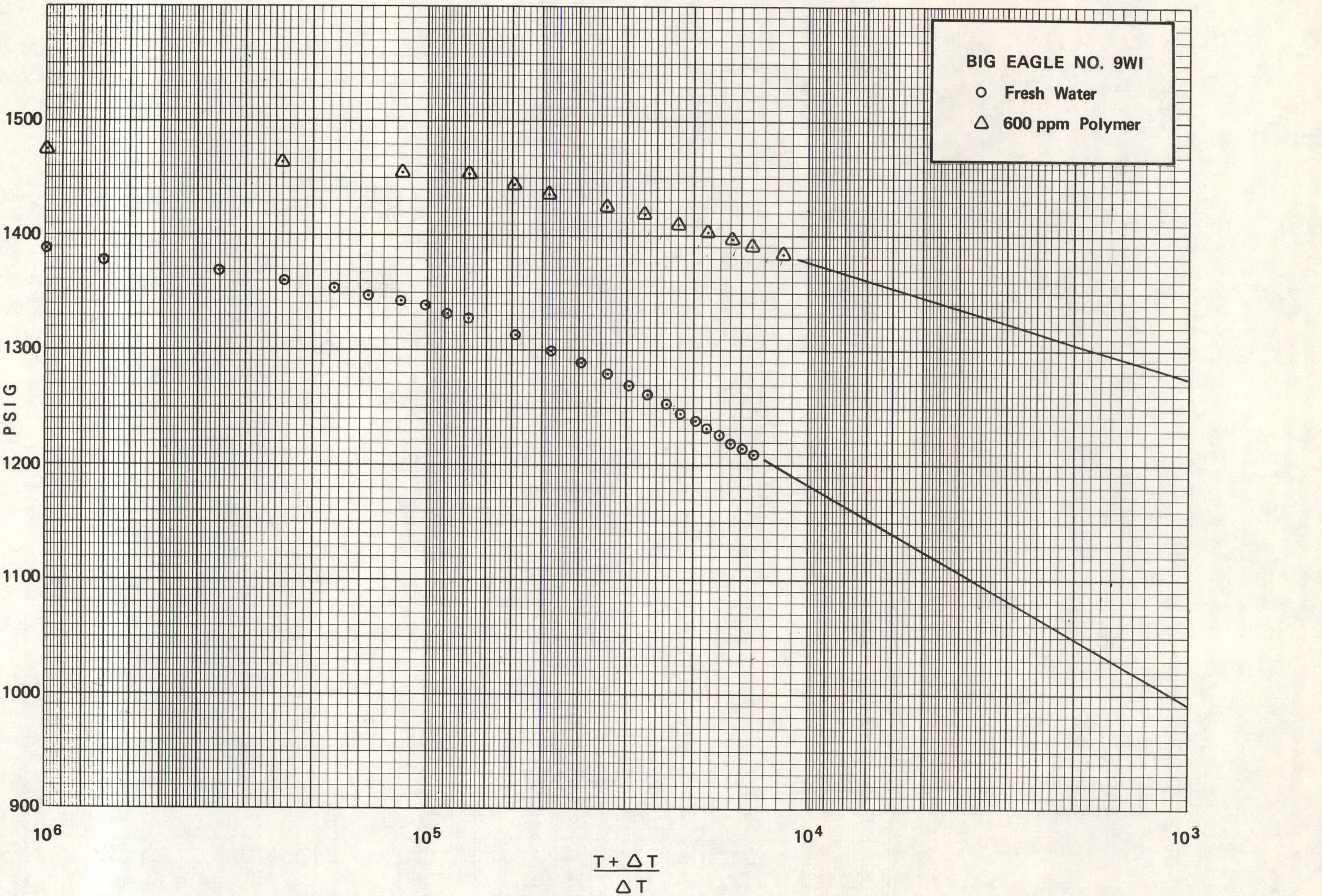

Hiram 16
Odell 1
BWPD
WOR
BOPD
BWPD
BOPD
WOR
WOR
Daily Oil Production (BOPD)
Daily Water Production (BWPD)
0
50
100
0
20
40
60
0
10
20
30
0
500
1000
1500
DEC. JAN. FEB. MAR. APR. MAY JUN. JUL. AUG. SEP. OCT. NOV.
1976
1977
1978
1979
1980

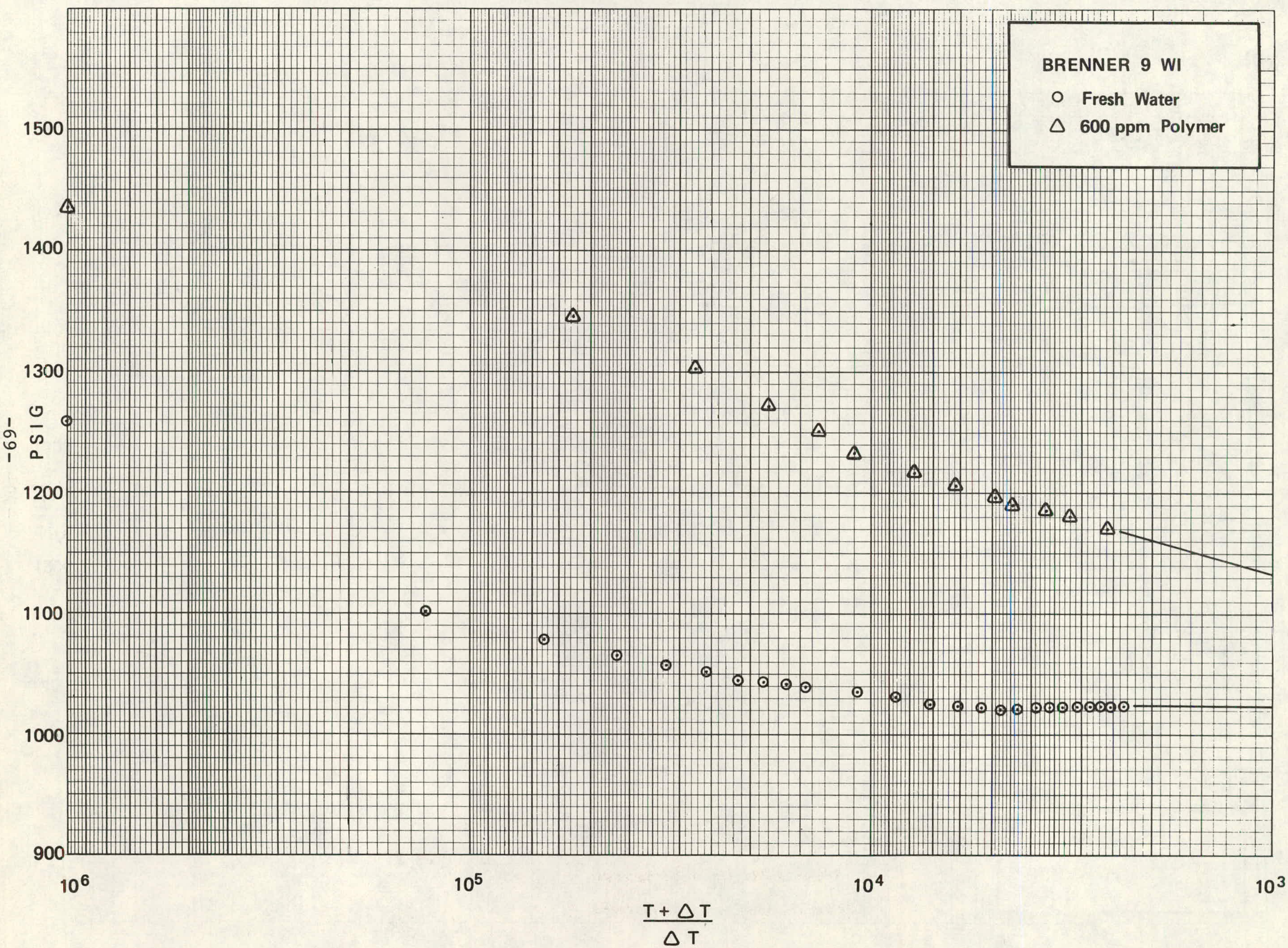

Pappin 4A
BWPD
WOR
BOPD
Pappin 15
BWPD
WOR
BOPD
WOR
Daily Oil Production (BOPD)
Daily Water Production (BWPD)
1976
1977
1978
1979
1980


Pappin 16
BWPD
WOR
BOPD
Skelly Barber 9
WOR
BWPD
BOPD
Daily Oil Production (BOPD)
WOR
Daily Water Production (BWPD)
1976
1977
1978
1979
1980

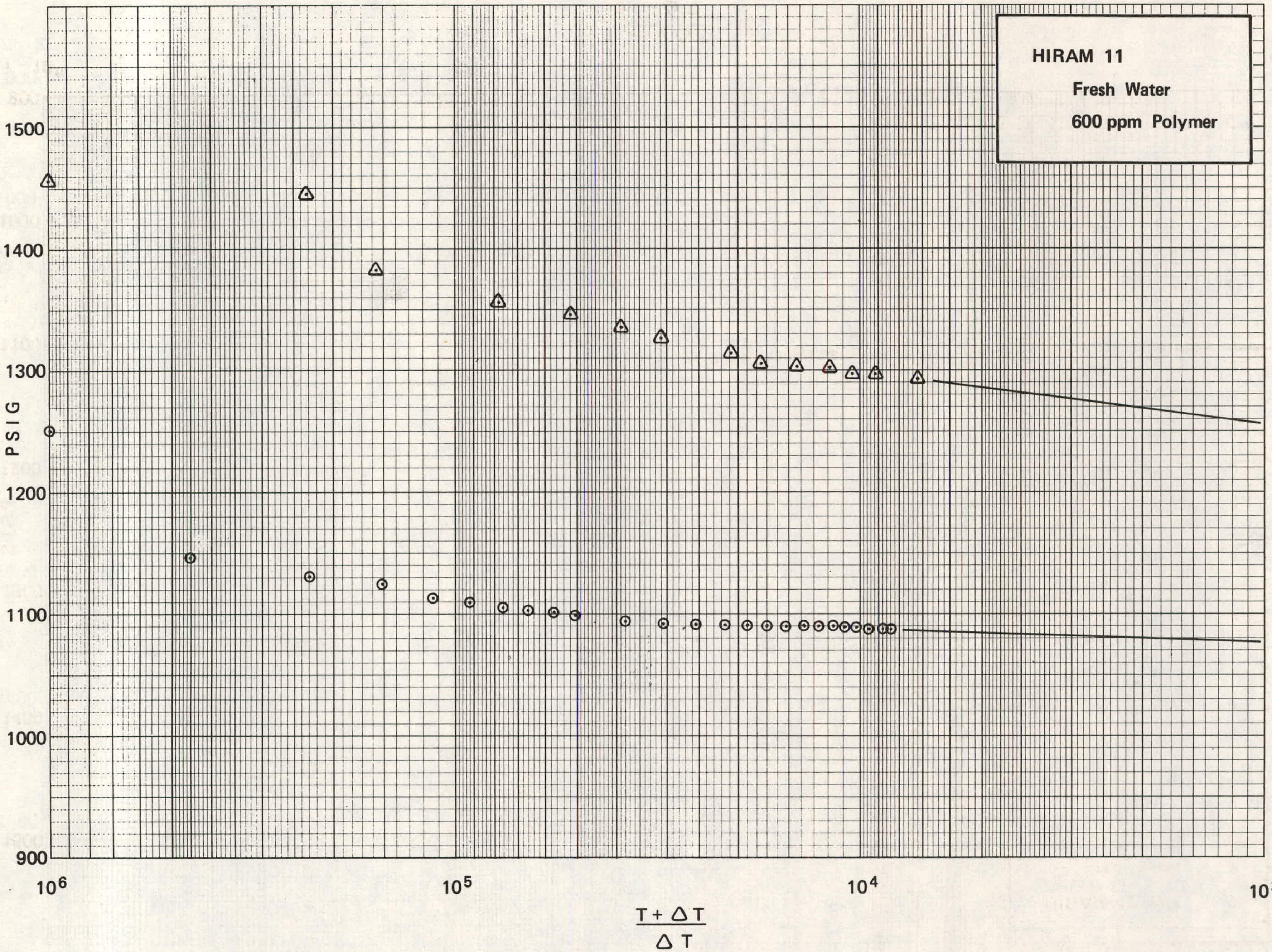

ART 7 WI
Fresh Water
600 ppm Polymer
PSIG
1500
1400
1300
1200
1100
1000
900
10^6
10^5
10^4
10^3
$\frac{T + \Delta T}{\Delta T}$


ART 8 WI
Fresh Water
600 ppm Polymer
PSIG
1500
1400
1300
1200
1100
1000
900
10^6
10^5
10^4
10^3
$\frac{T + \Delta T}{\Delta T}$
-67-

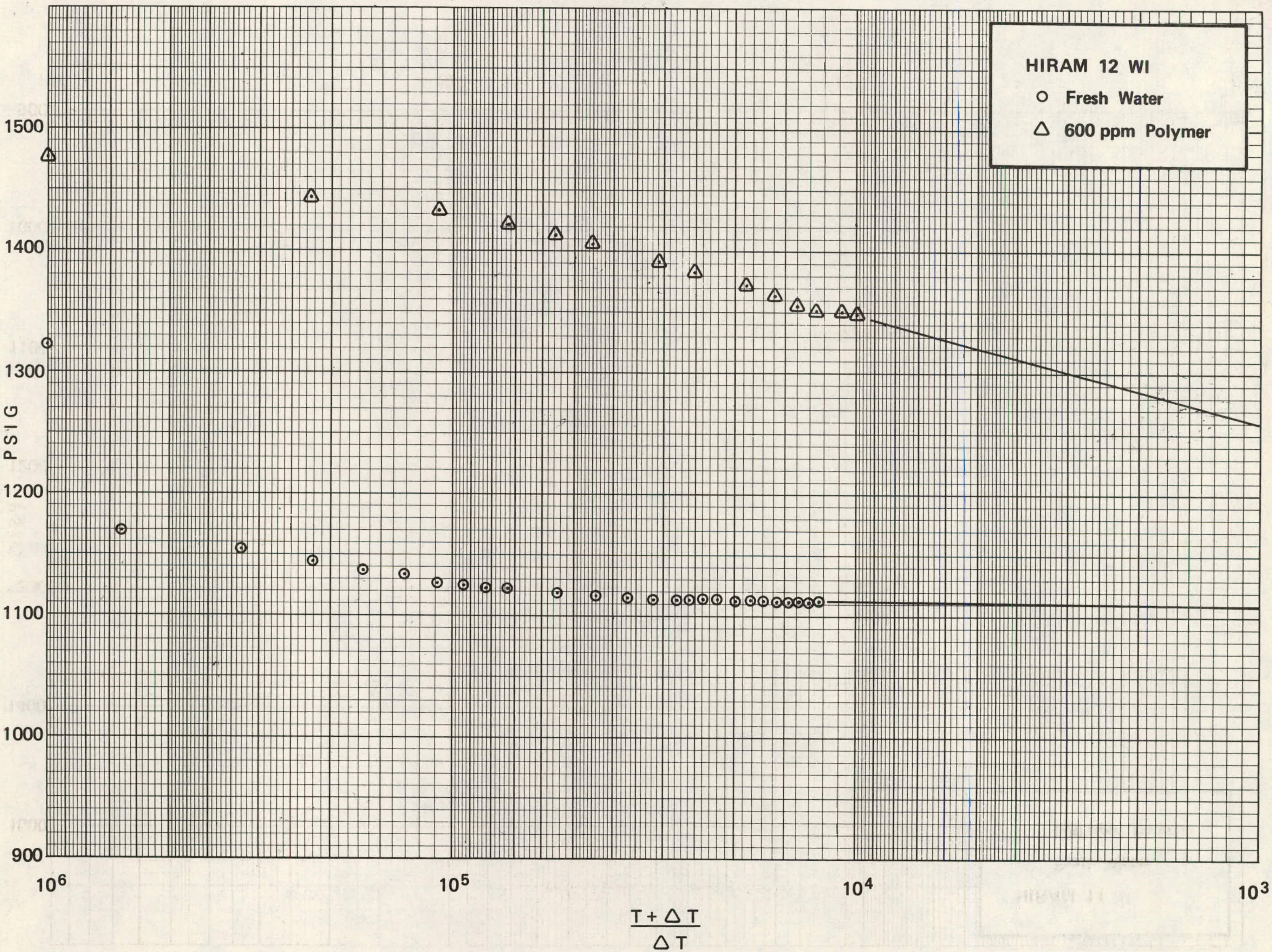

BIG EAGLE NO. 9WI
○ Fresh Water
△ 600 ppm Polymer
PSIG
1500
1400
1300
1200
1100
1000
900
10^6
10^5
10^4
10^3
$\frac{T + \Delta T}{\Delta T}$



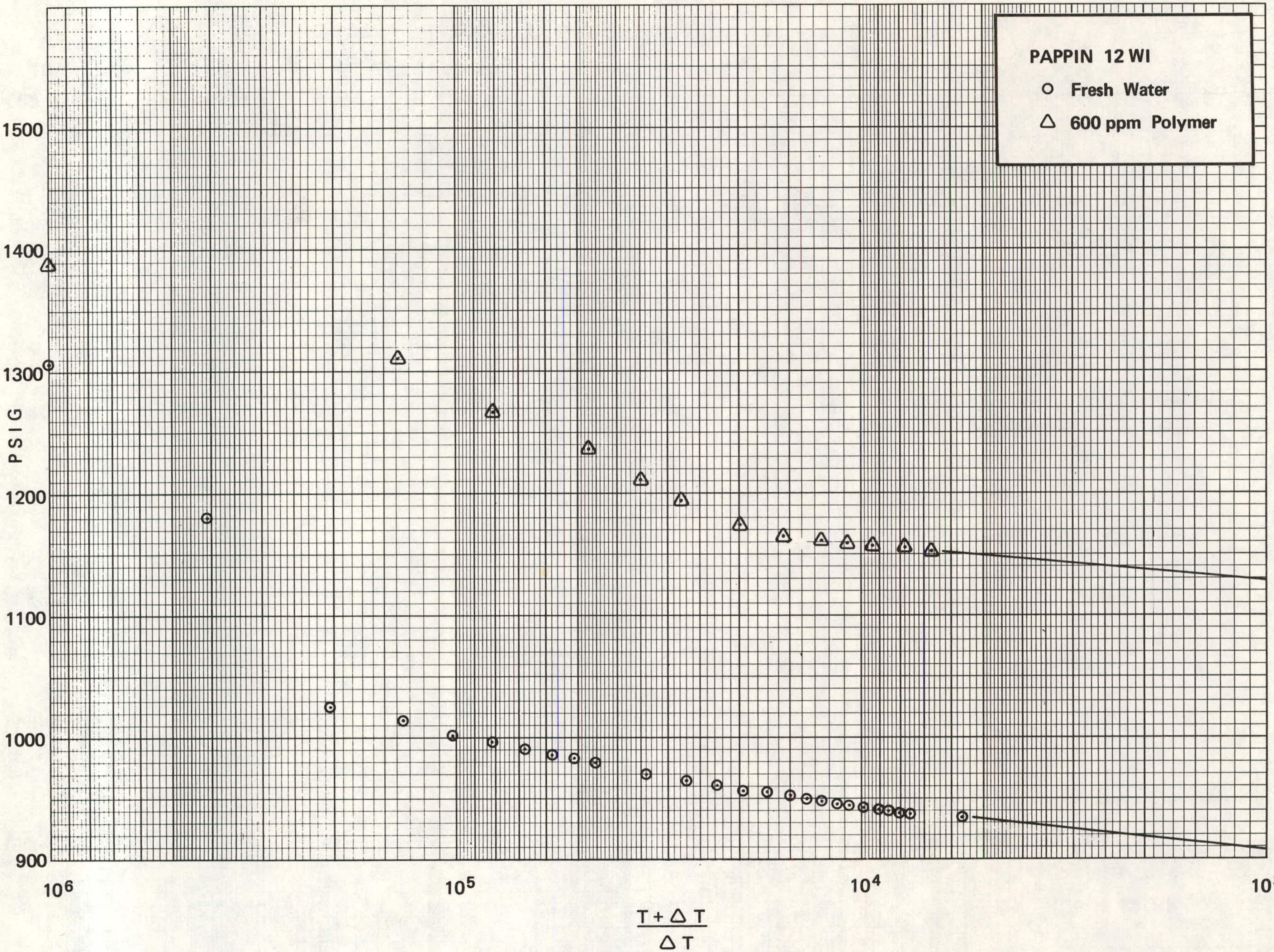
BRENNER 9 WI
○ Fresh Water
△ 600 ppm Polymer
-69-
PSIG
1500
1400
1300
1200
1100
1000
900
10^6
10^5
10^4
10^3
$\frac{T + \Delta T}{\Delta T}$



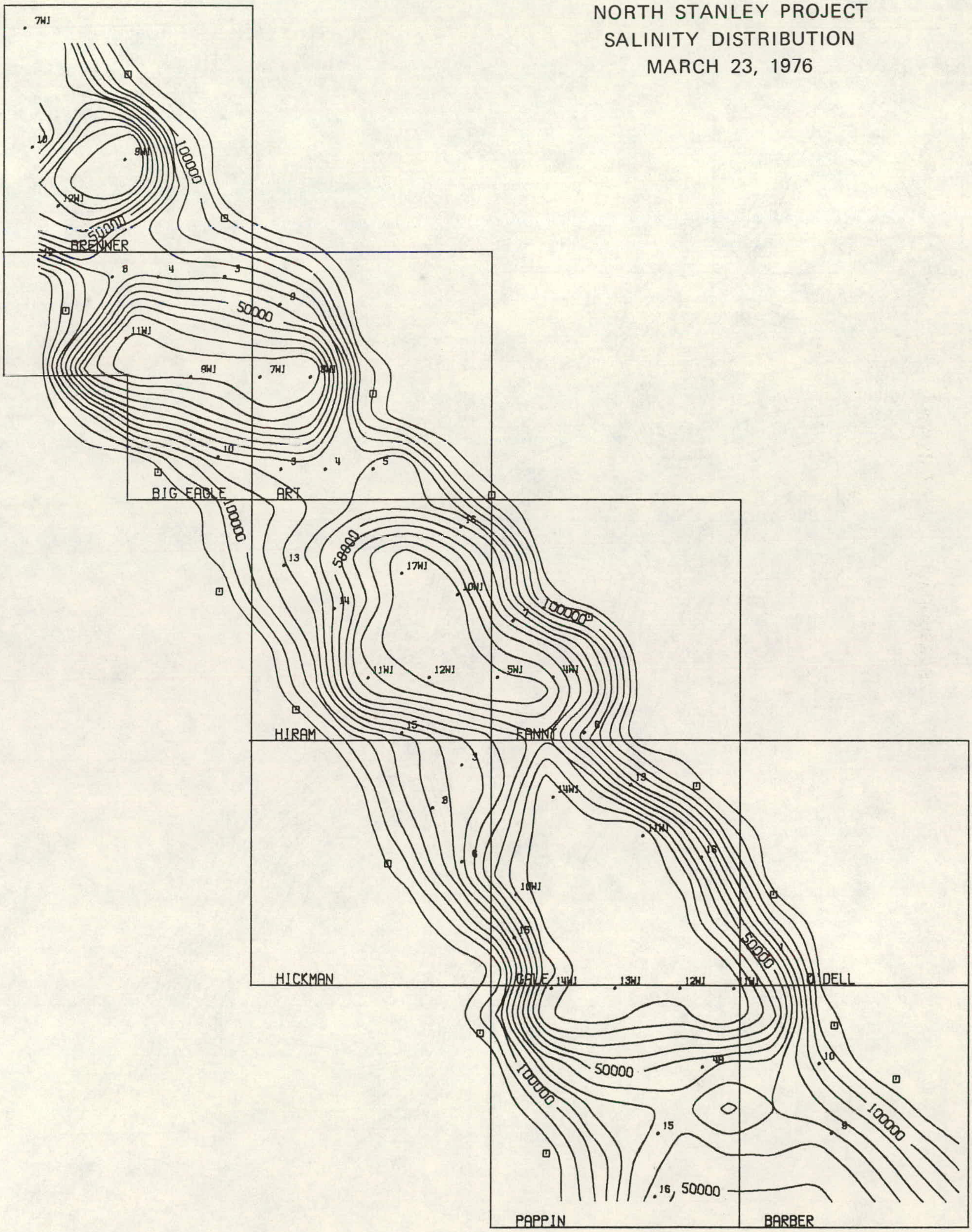
HIRAM 11
Fresh Water
600 ppm Polymer
PSIG
1500
1400
1300
1200
1100
1000
900
10^6
10^5
10^4
10^3
$\frac{T + \Delta T}{\Delta T}$



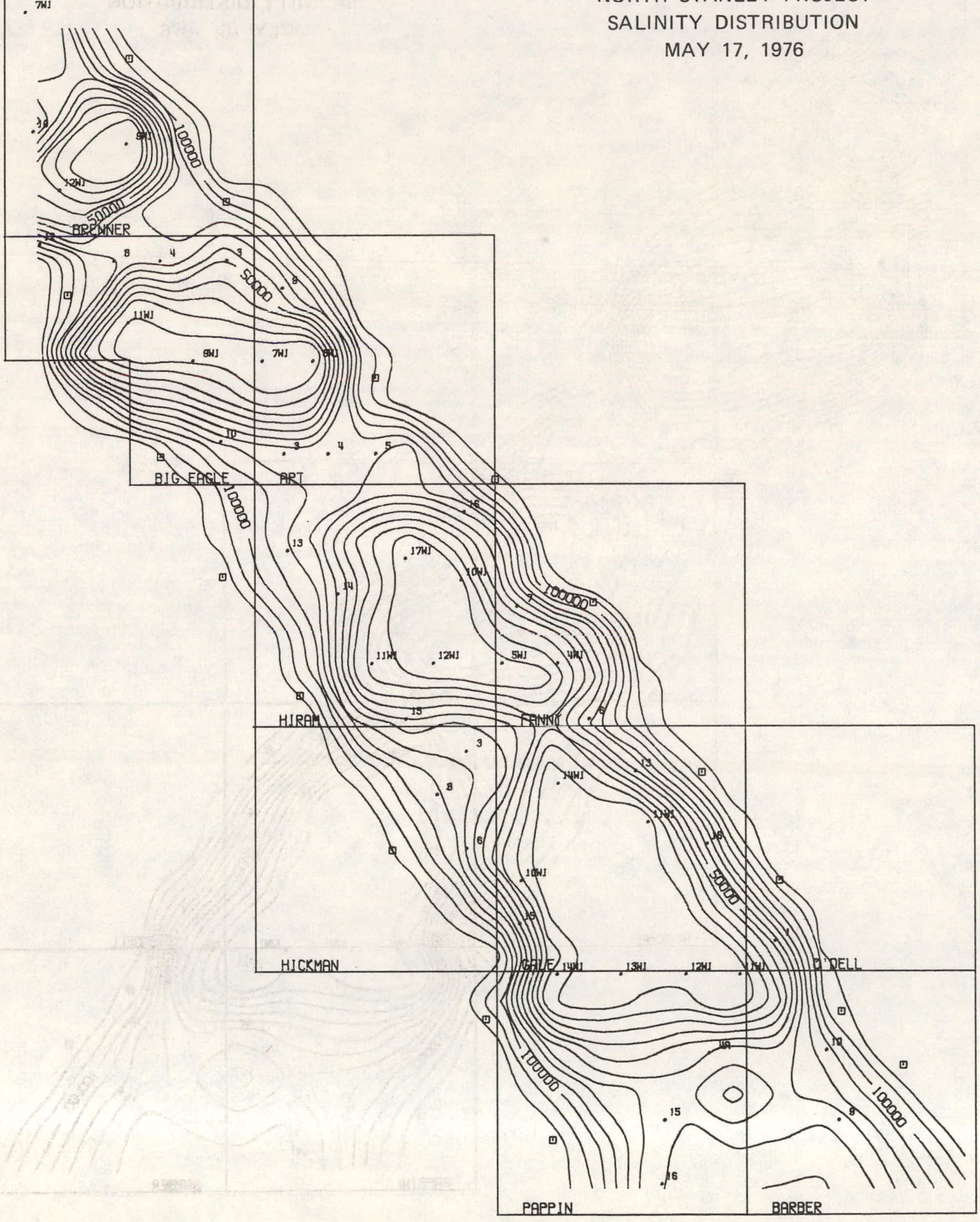
HIRAM 12 WI
○ Fresh Water
△ 600 ppm Polymer
PSIG
1500
1400
1300
1200
1100
1000
900
10^6
10^5
10^4
10^3
$\frac{T + \Delta T}{\Delta T}$


PAPPIN 12 WI
O Fresh Water
△ 600 ppm Polymer
PSIG
1500
1400
1300
1200
1100
1000
900
10^6
10^5
10^4
10^3
$\frac{T + \Delta T}{\Delta T}$

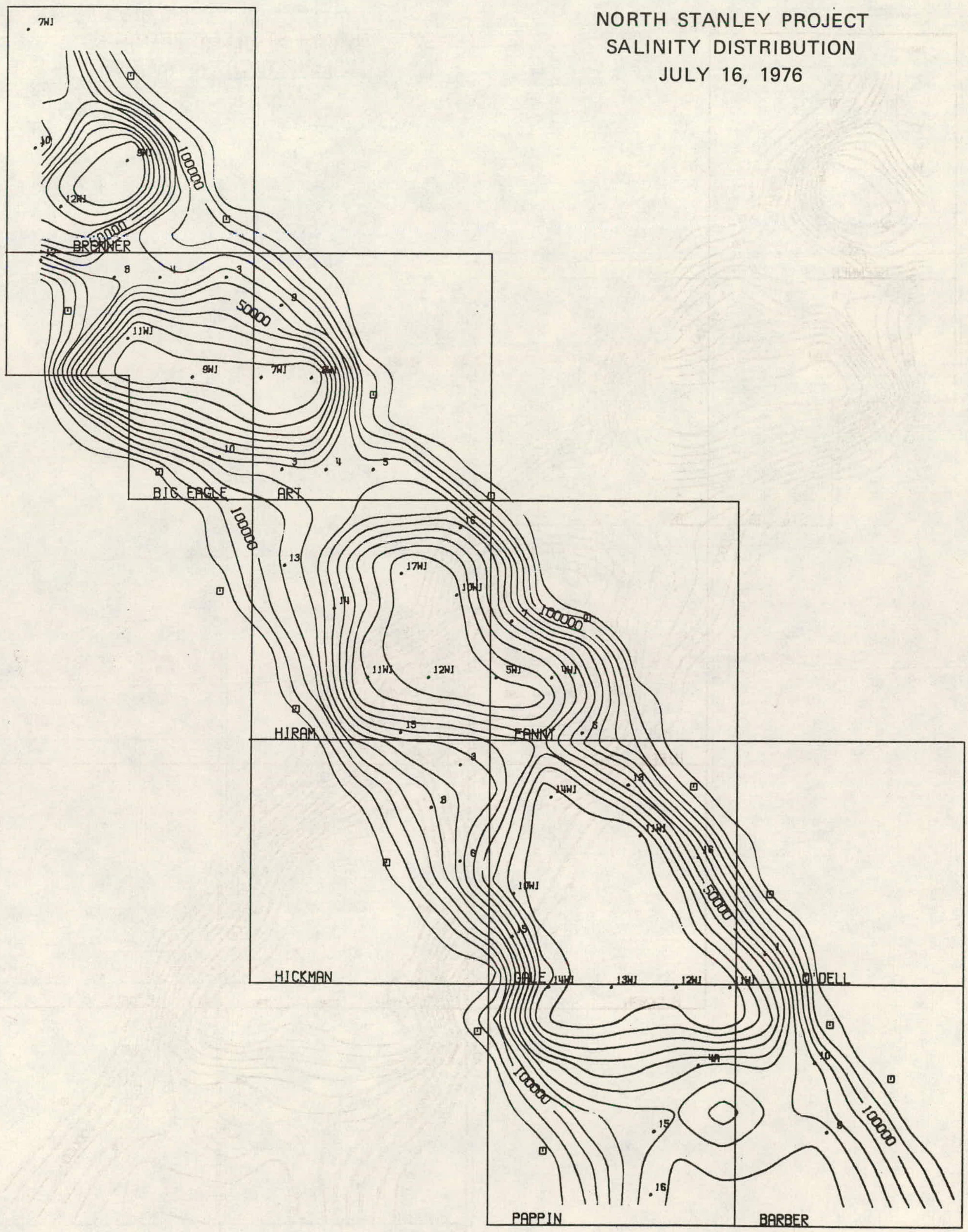
NORTH STANLEY PROJECT
SALINITY DISTRIBUTION
MARCH 23, 1976



NORTH STANLEY PROJECT
SALINITY DISTRIBUTION
MAY 17, 1976



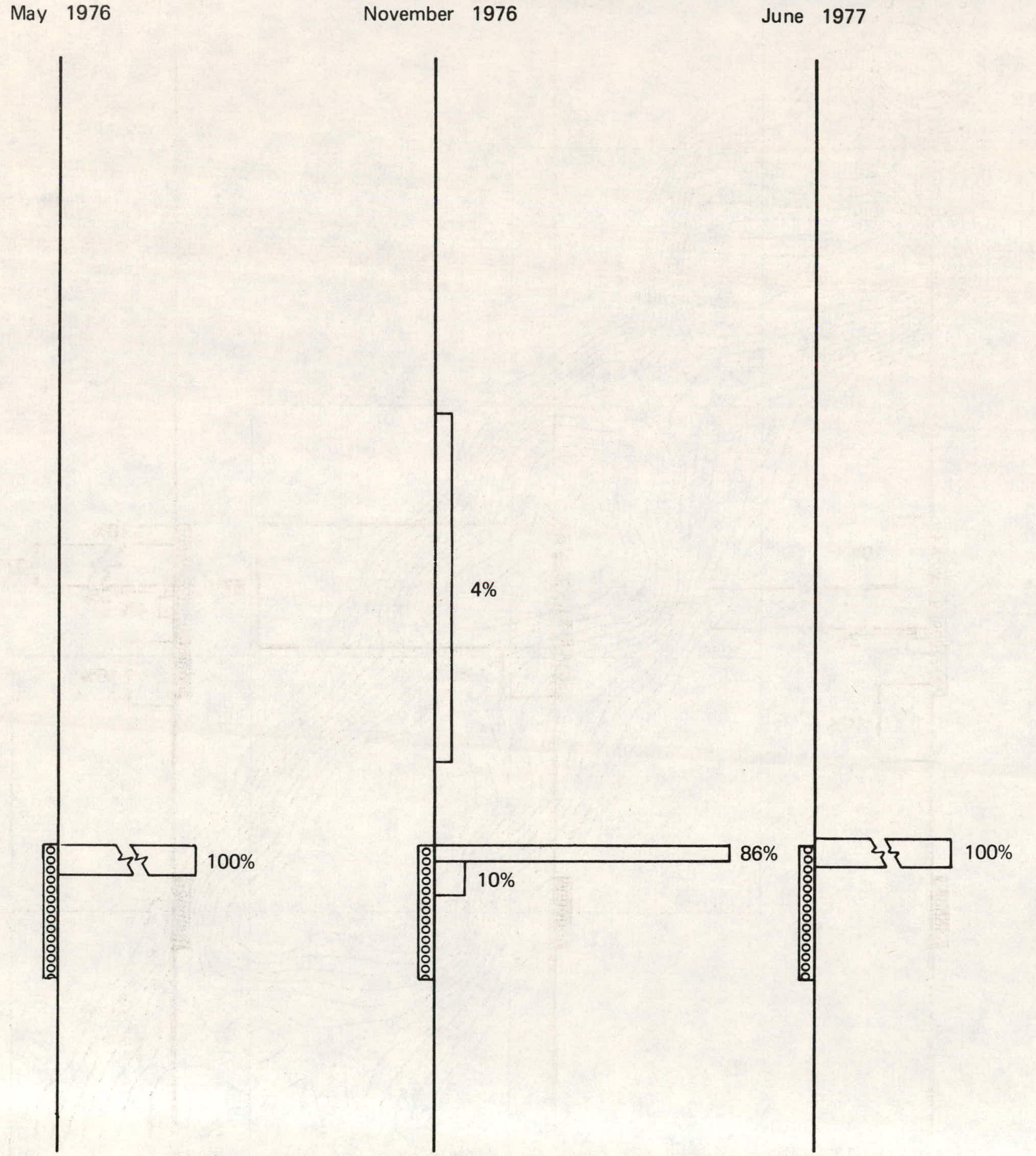
NORTH STANLEY PROJECT
SALINITY DISTRIBUTION
JULY 16, 1976



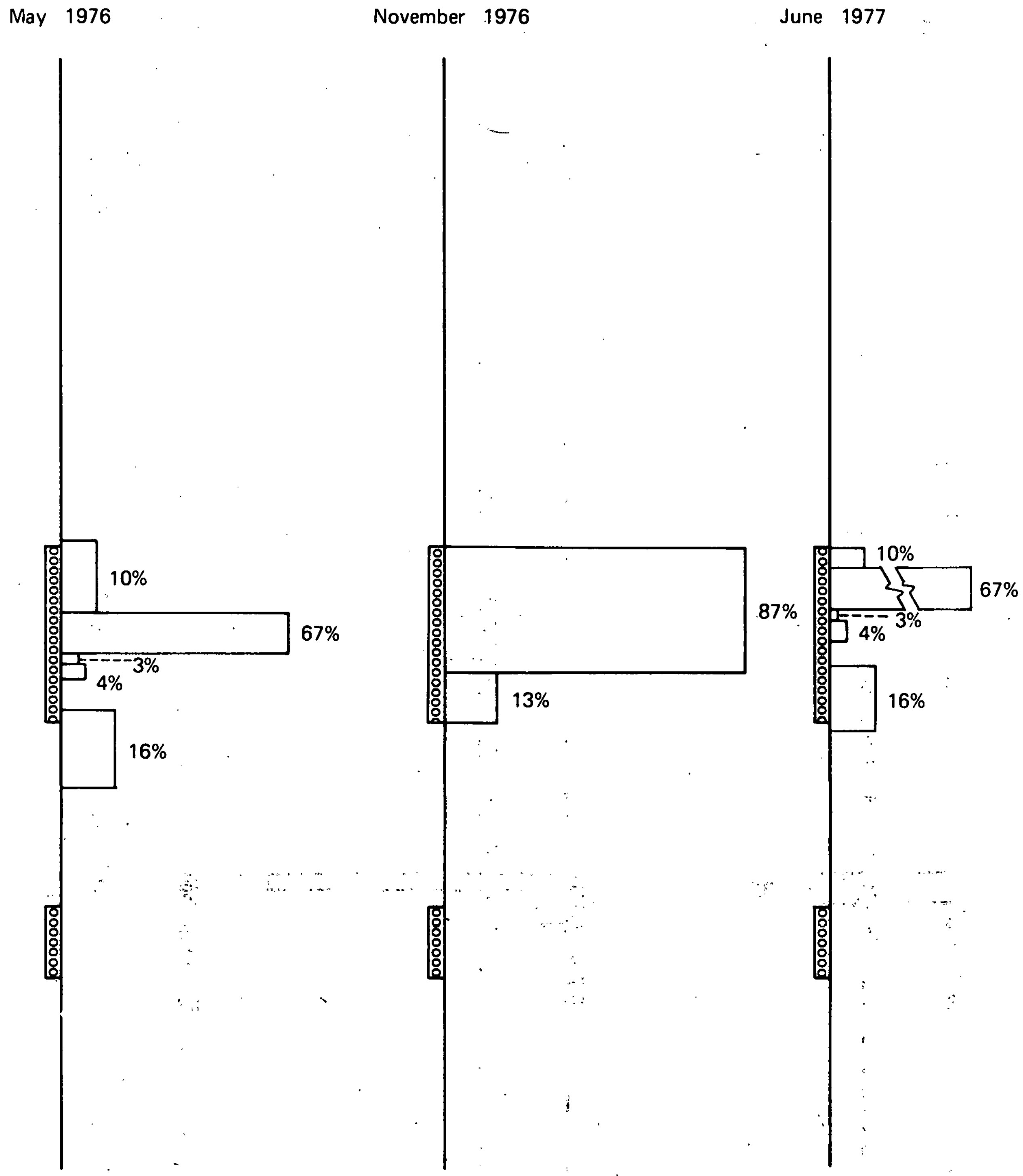
NORTH STANLEY PROJECT
SALINITY DISTRIBUTION
SEPTEMBER 20, 1976

NORTH STANLEY PROJECT
SALINITY DISTRIBUTION
NOVEMBER 20, 1976

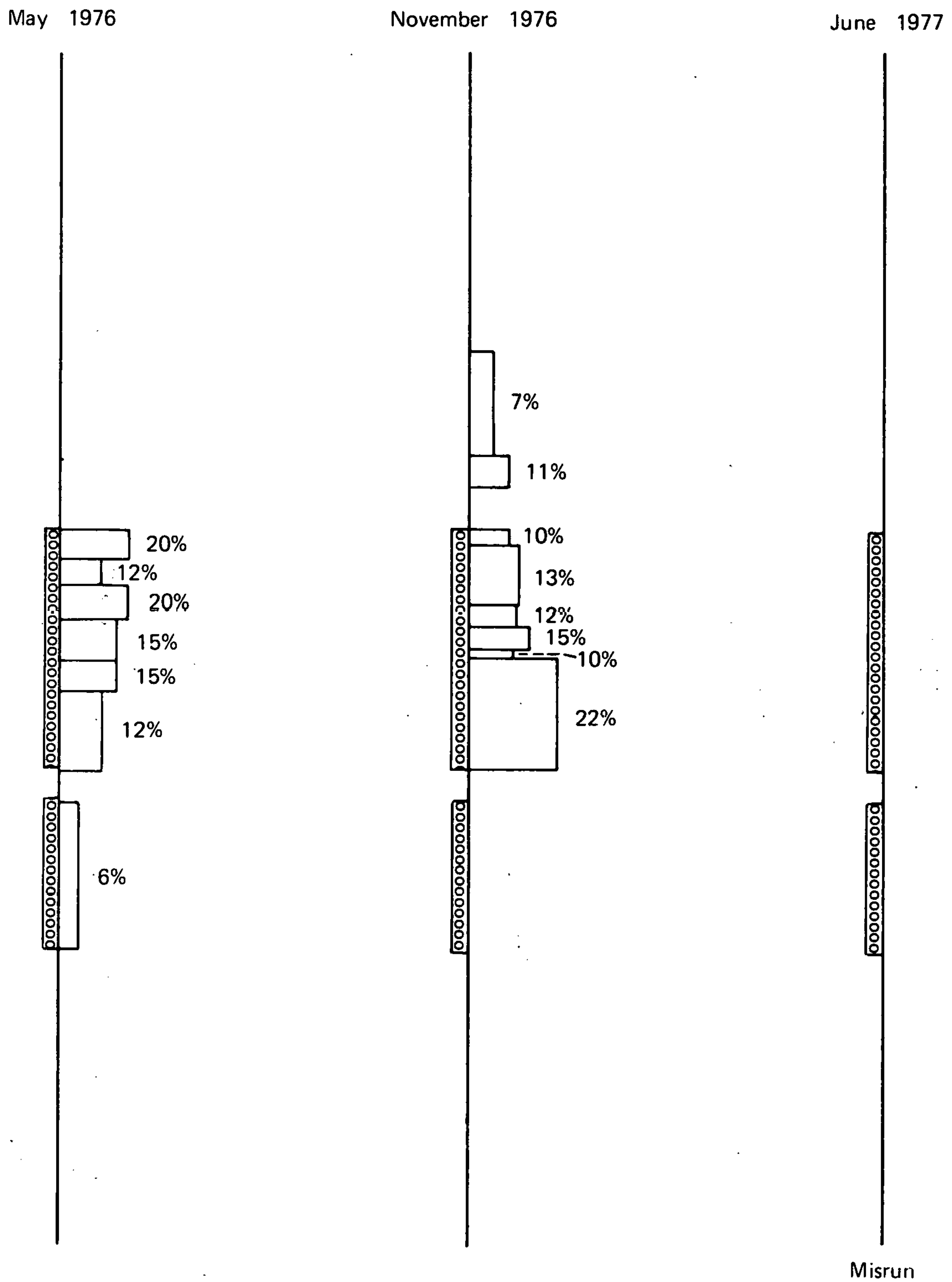
INJECTION PROFILES
ART 7 WI



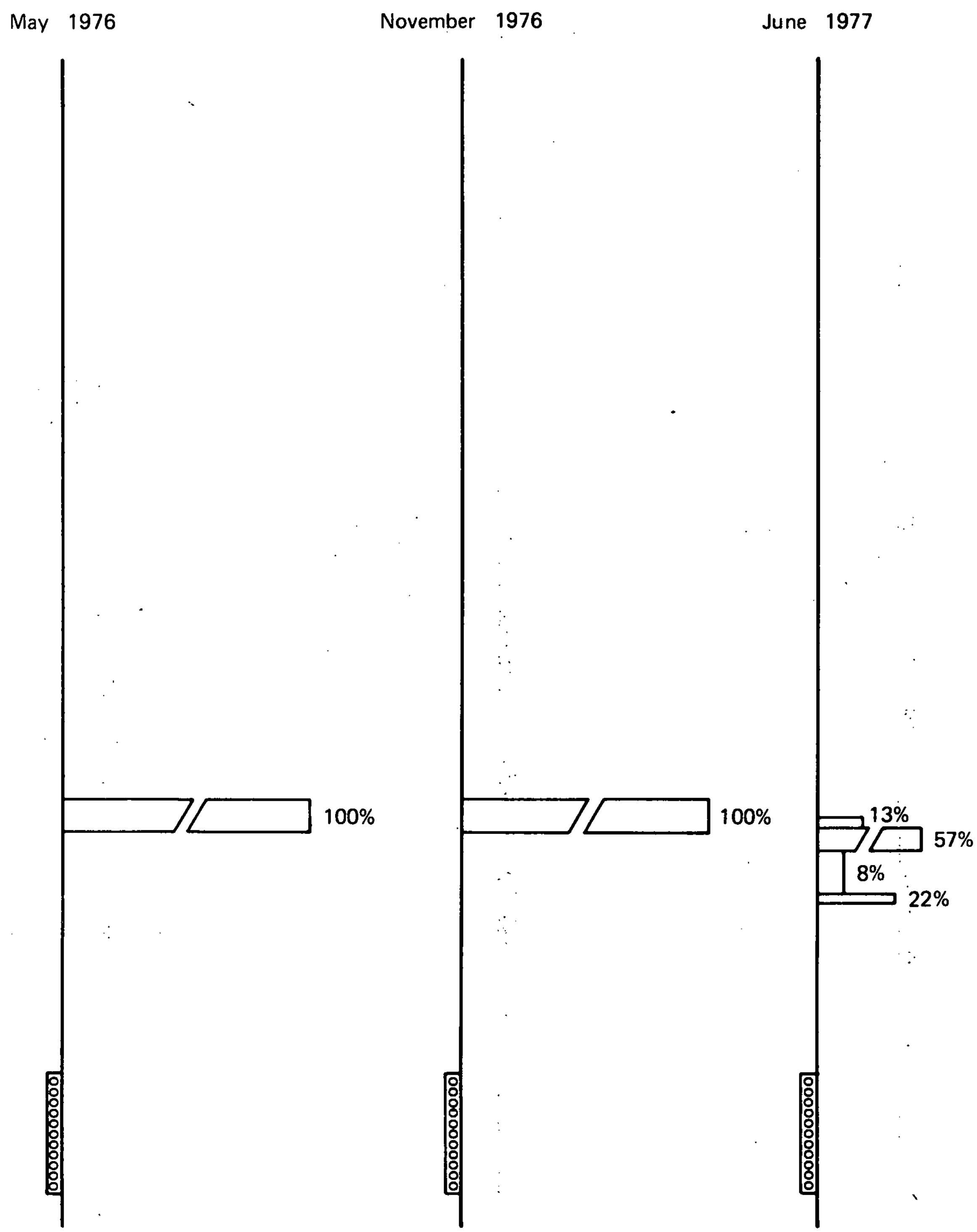
INJECTION PROFILES
ART 8 WI



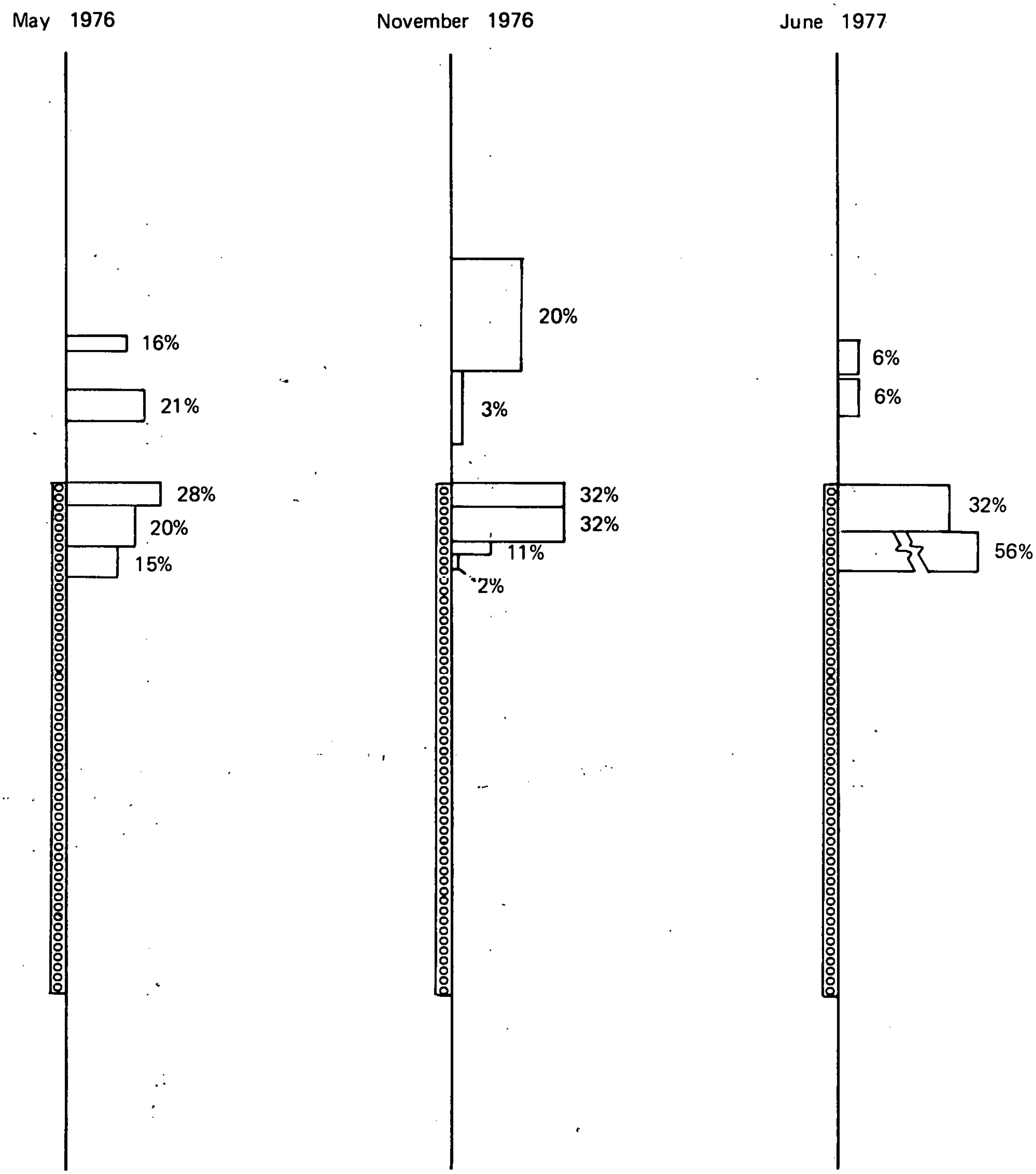
INJECTION PROFILES
BIG EAGLE 9 WI



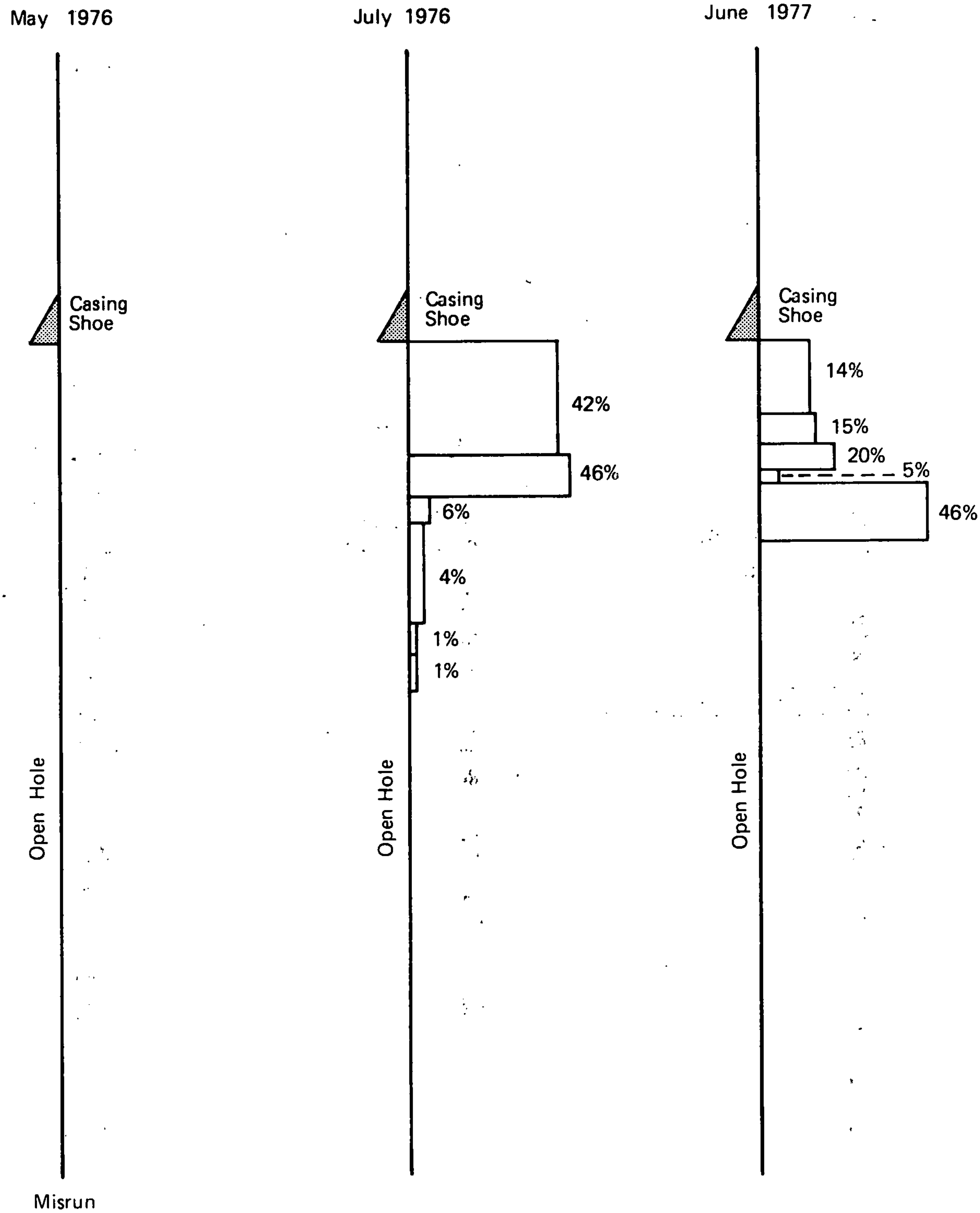
INJECTION PROFILES
BIG EAGLE 11 WI



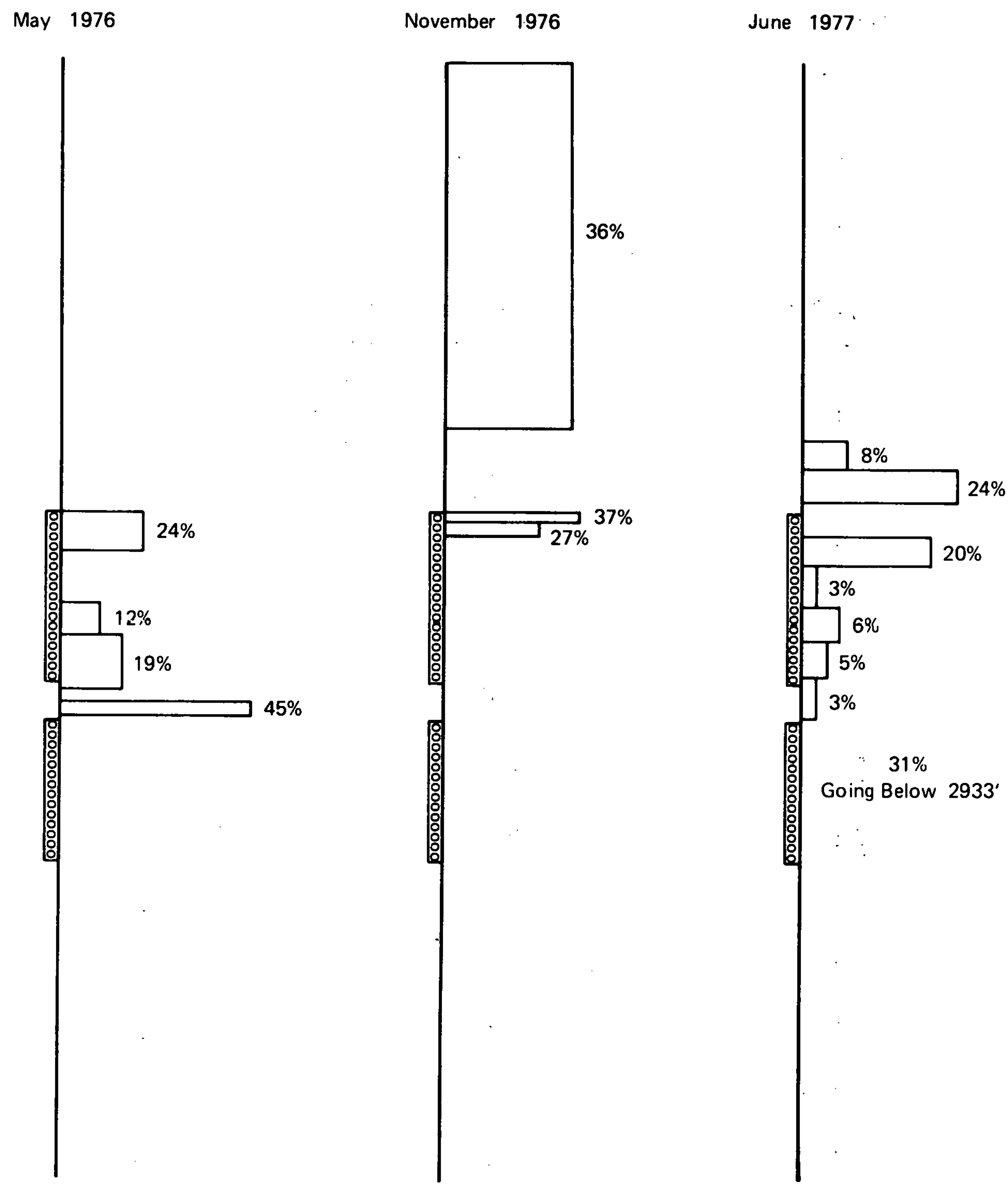
INJECTION PROFILES
BRENNER 7 WI



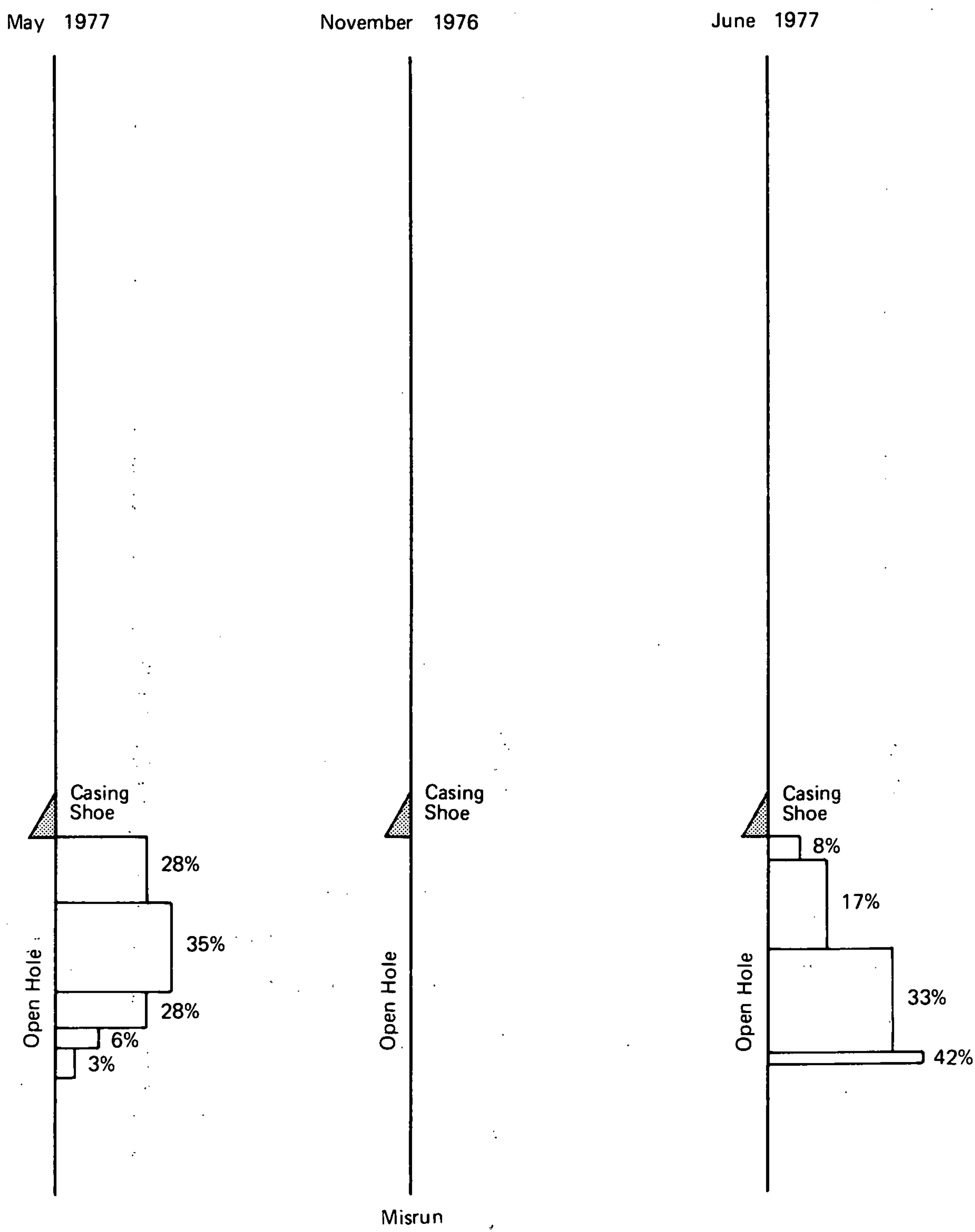
INJECTION PROFILES
BRENNER 9 WI



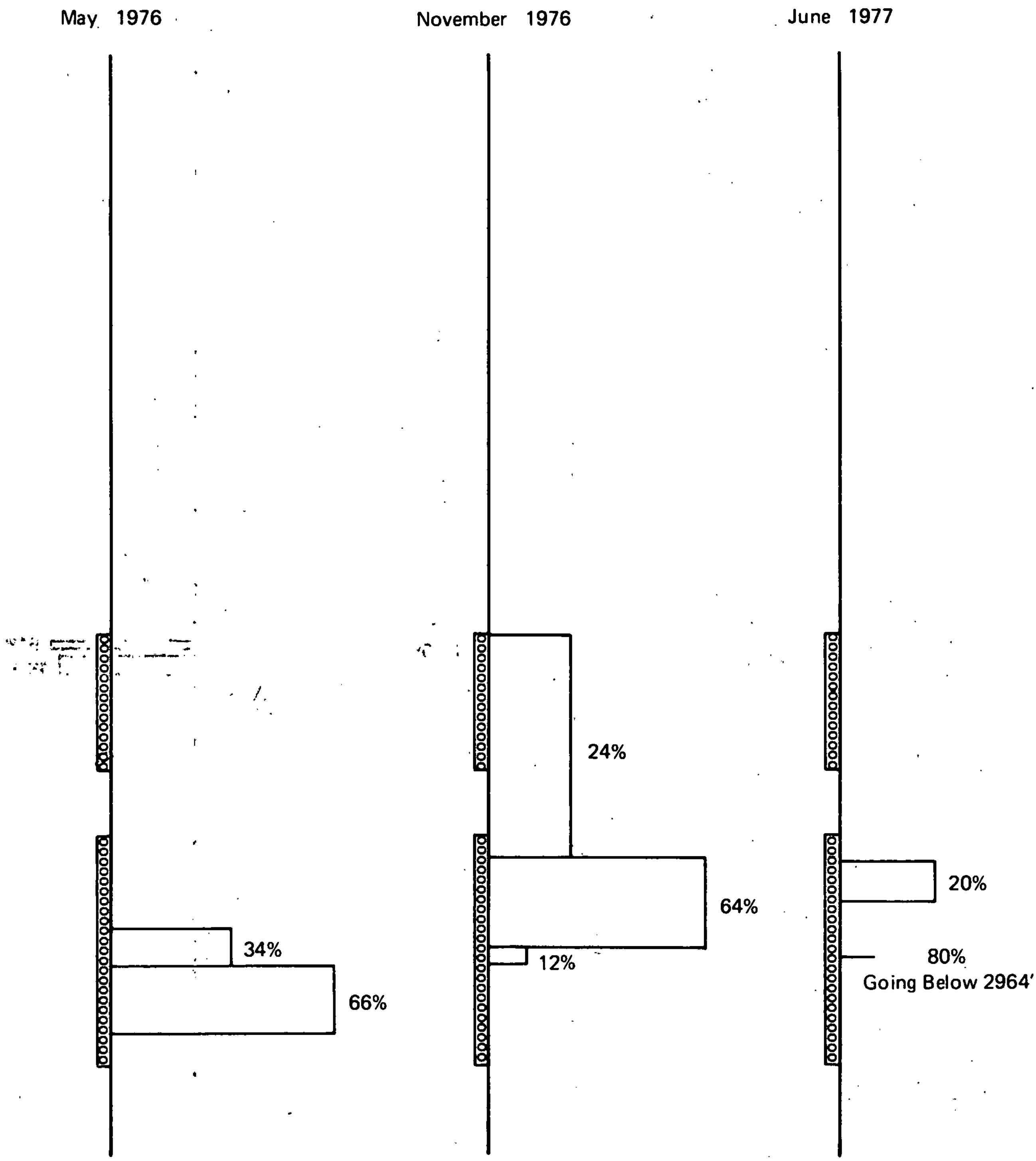
INJECTION PROFILES
BRENNER 12 WI



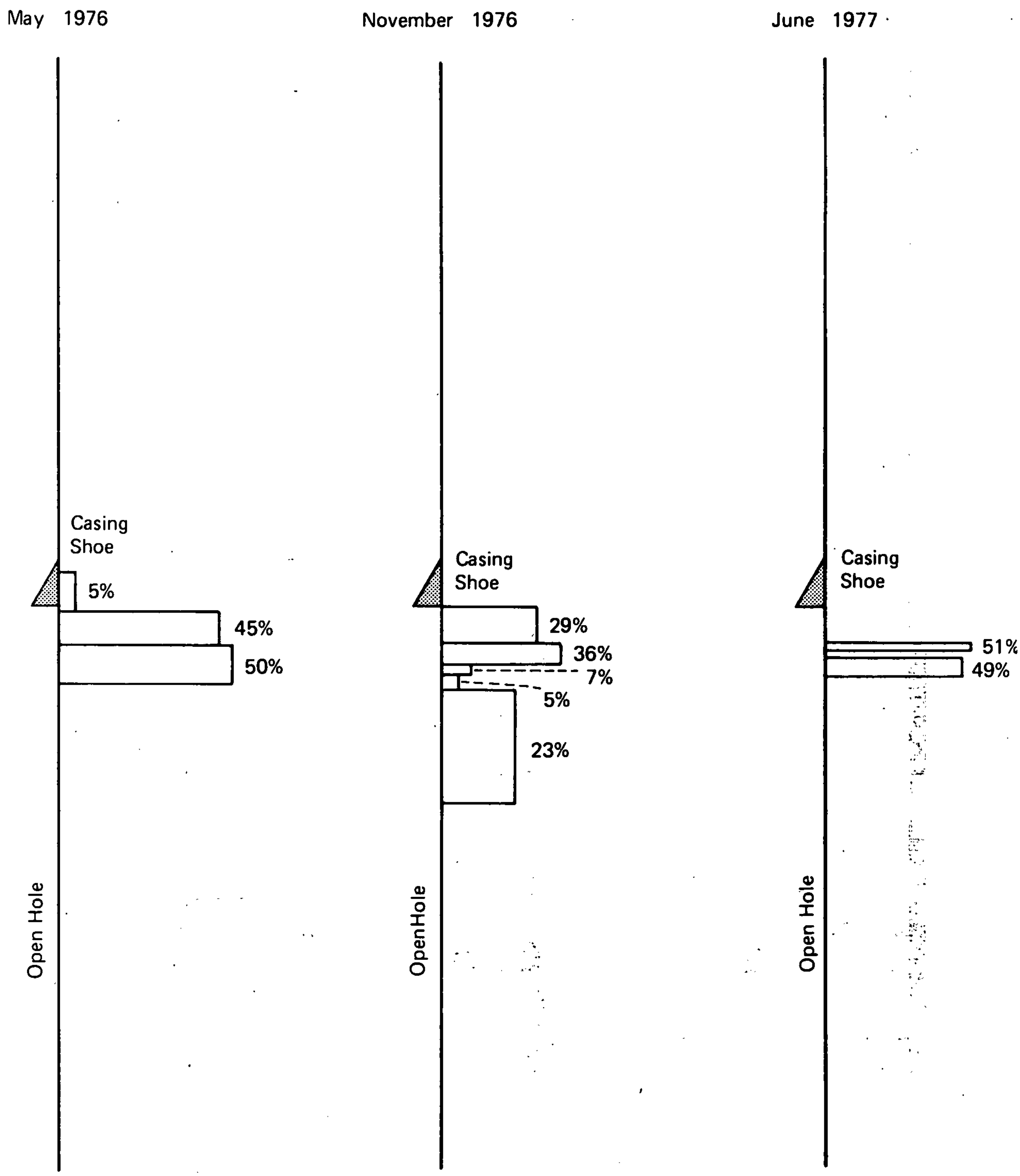
INJECTION PROFILES
FANNY 4 WI



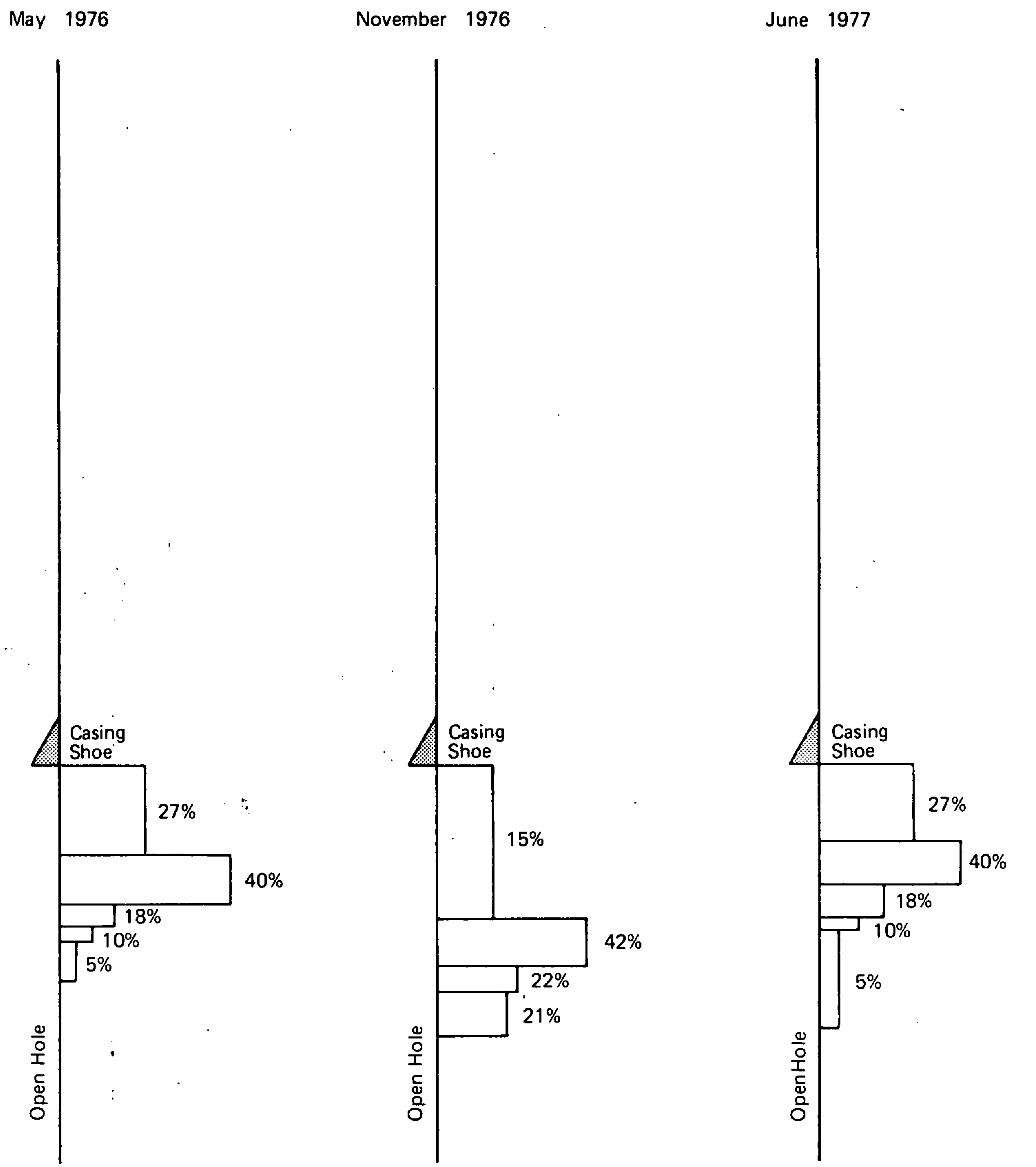
INJECTION PROFILES
FANNY 5 WI



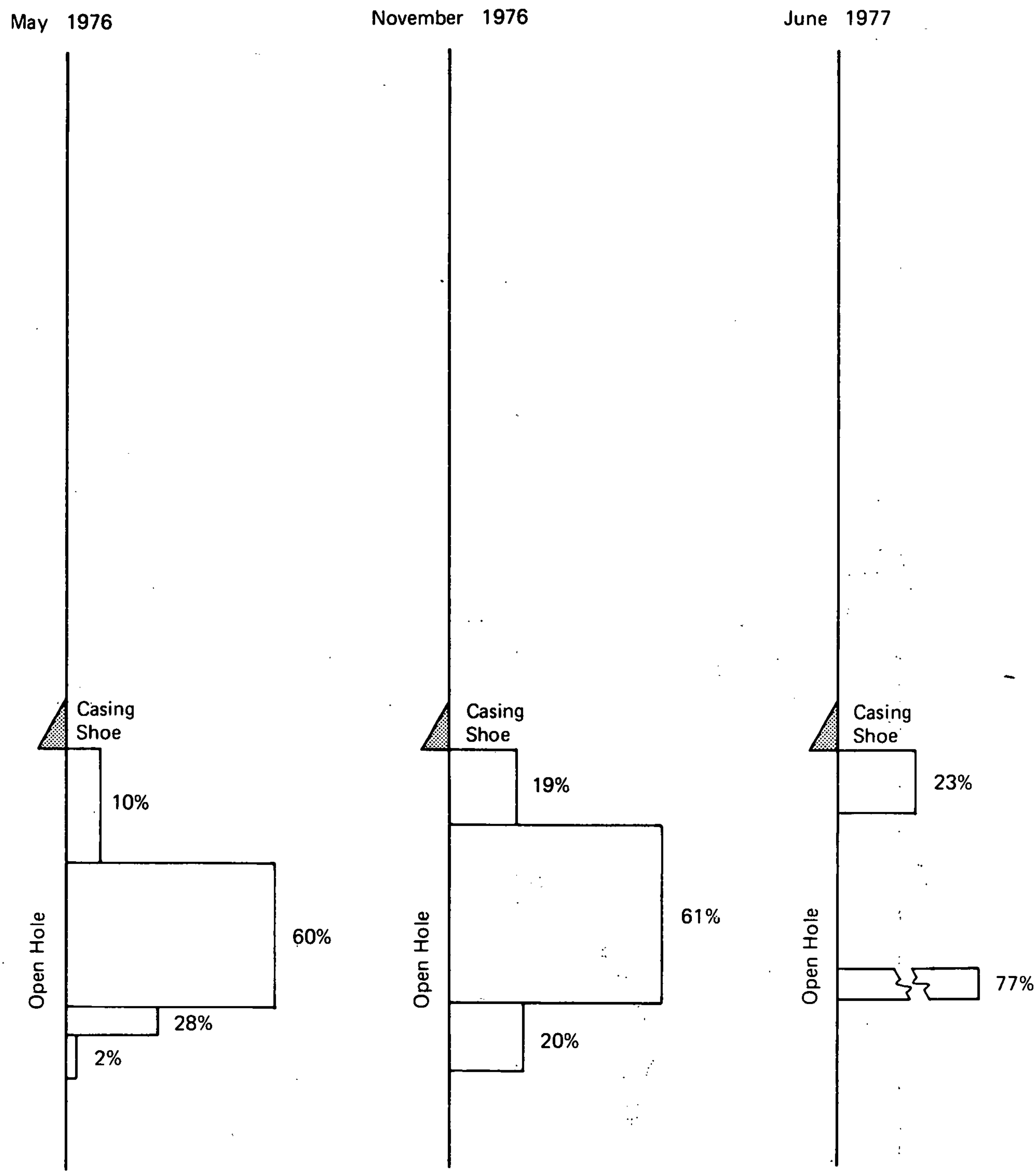
INJECTION PROFILES
GALE 10 WI



INJECTION PROFILES
GALE 11 WI

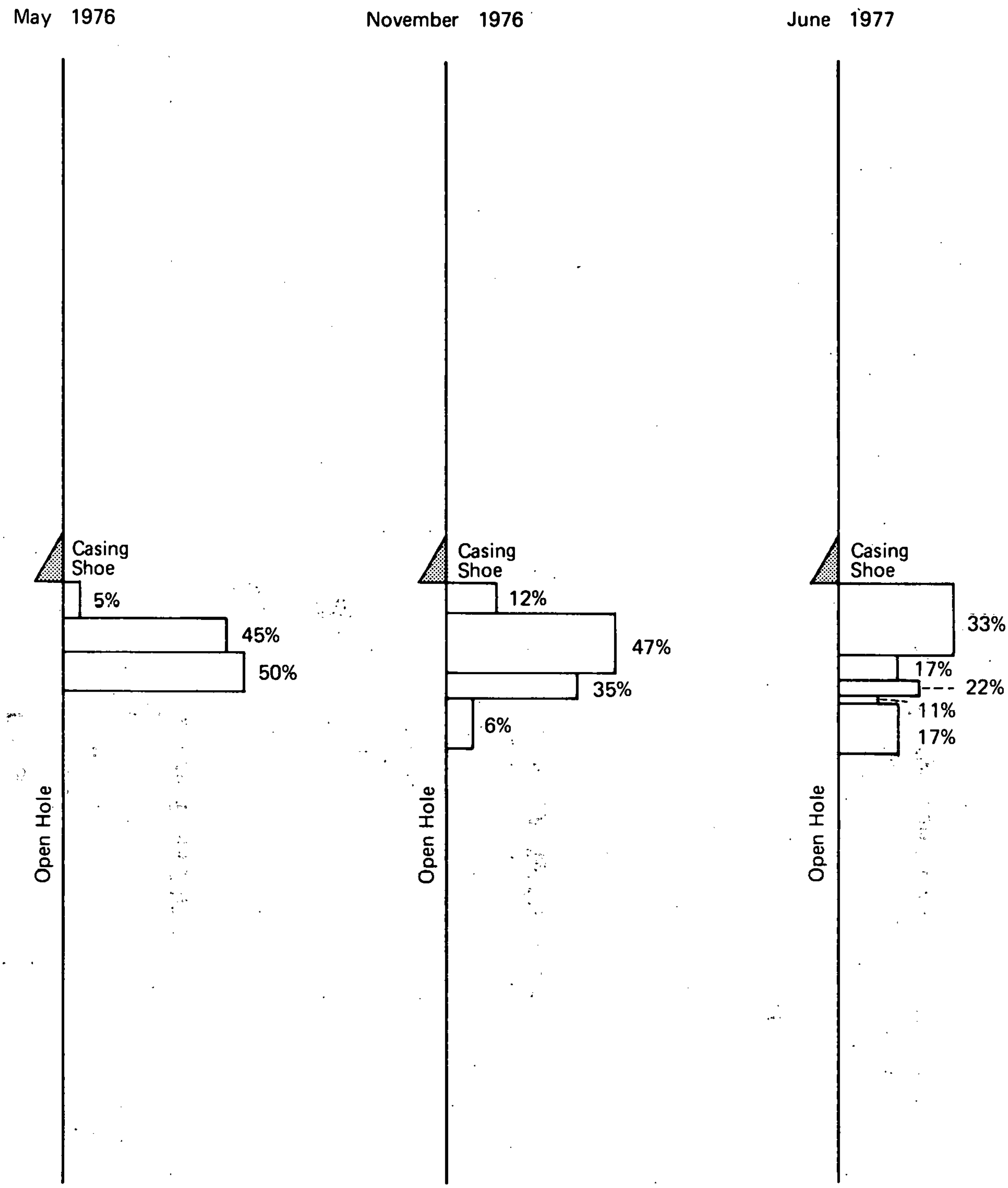


INJECTION PROFILES
GALE 14 WI

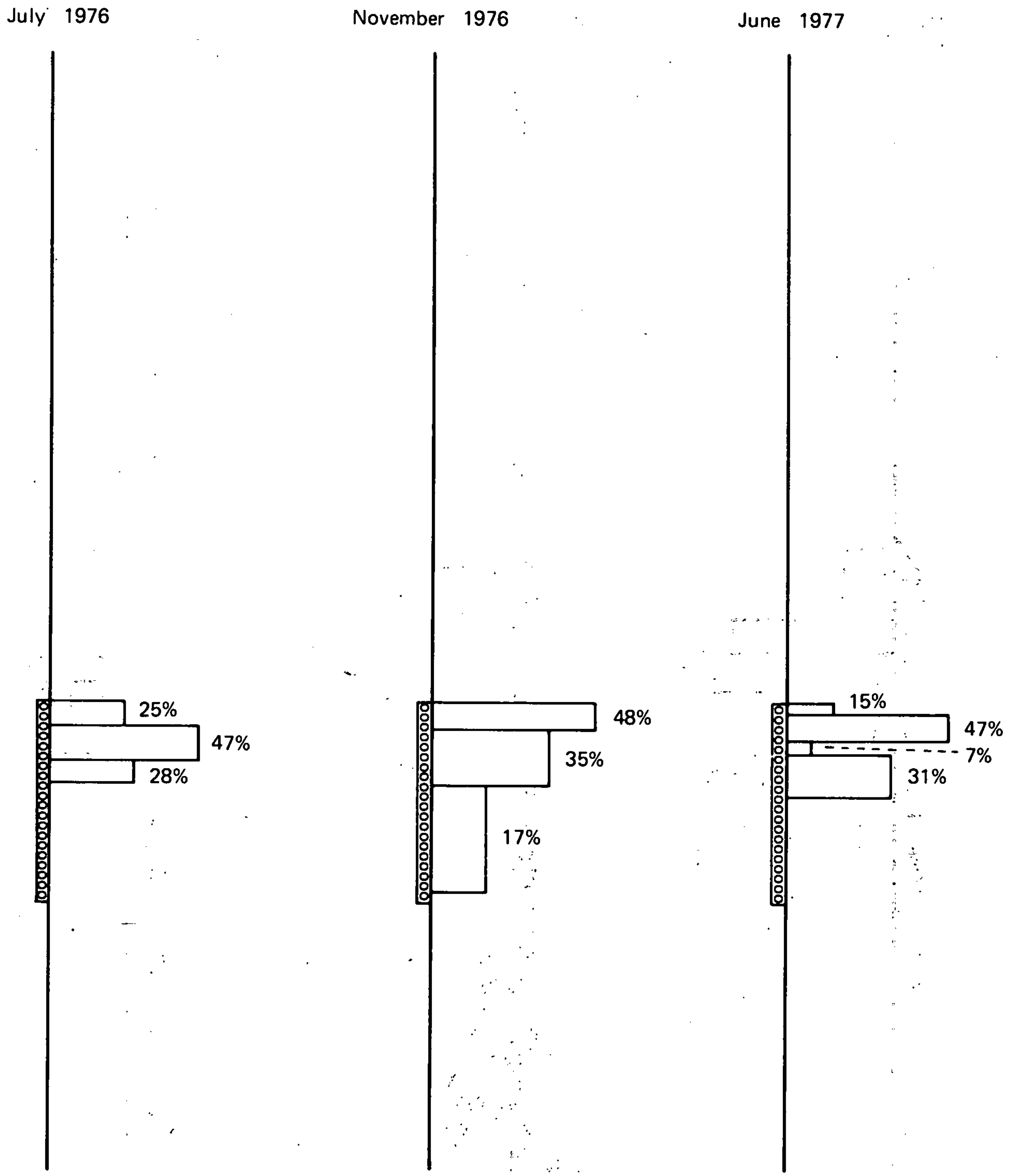


INJECTION PROFILES

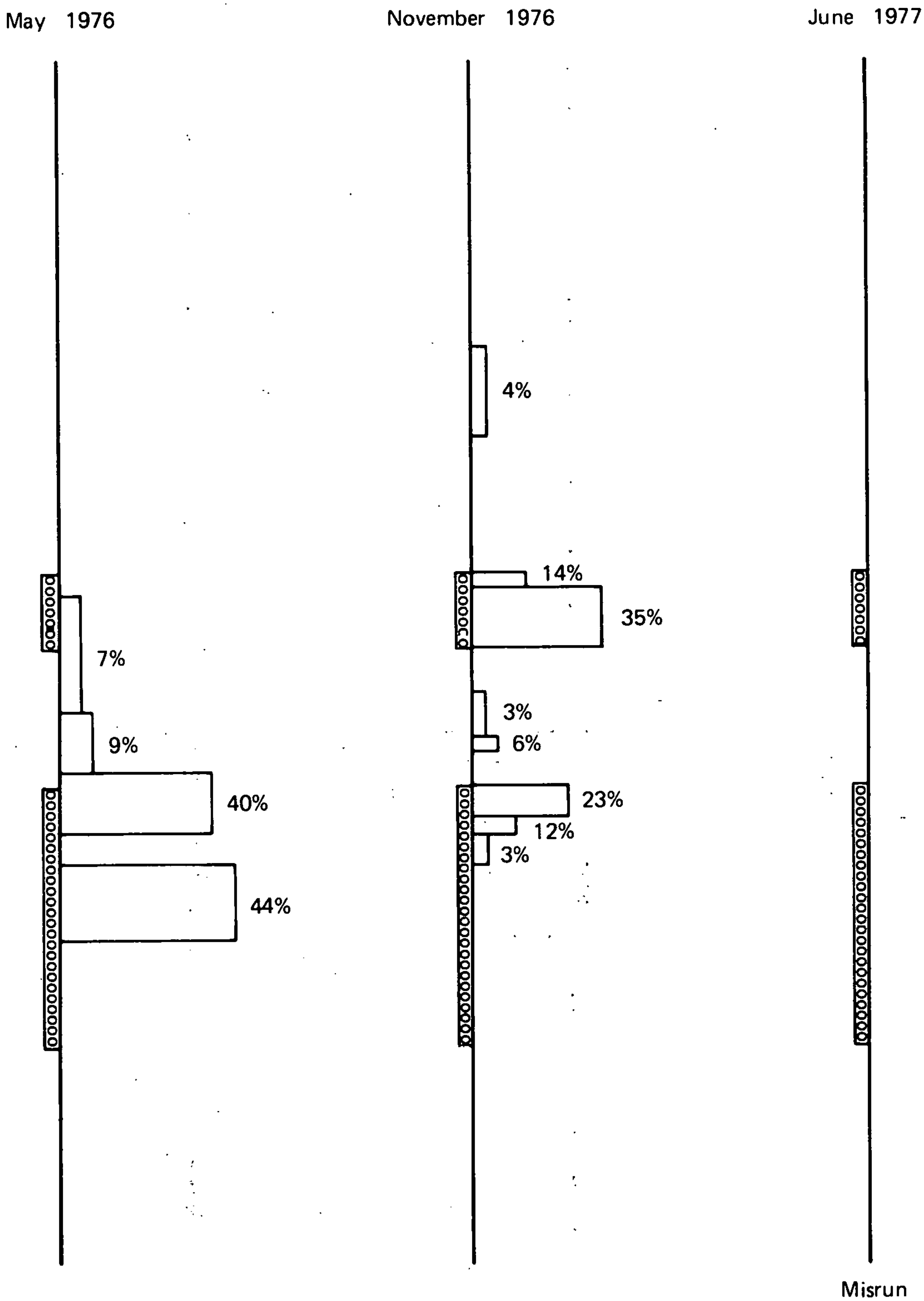
HIRAM 10 WI



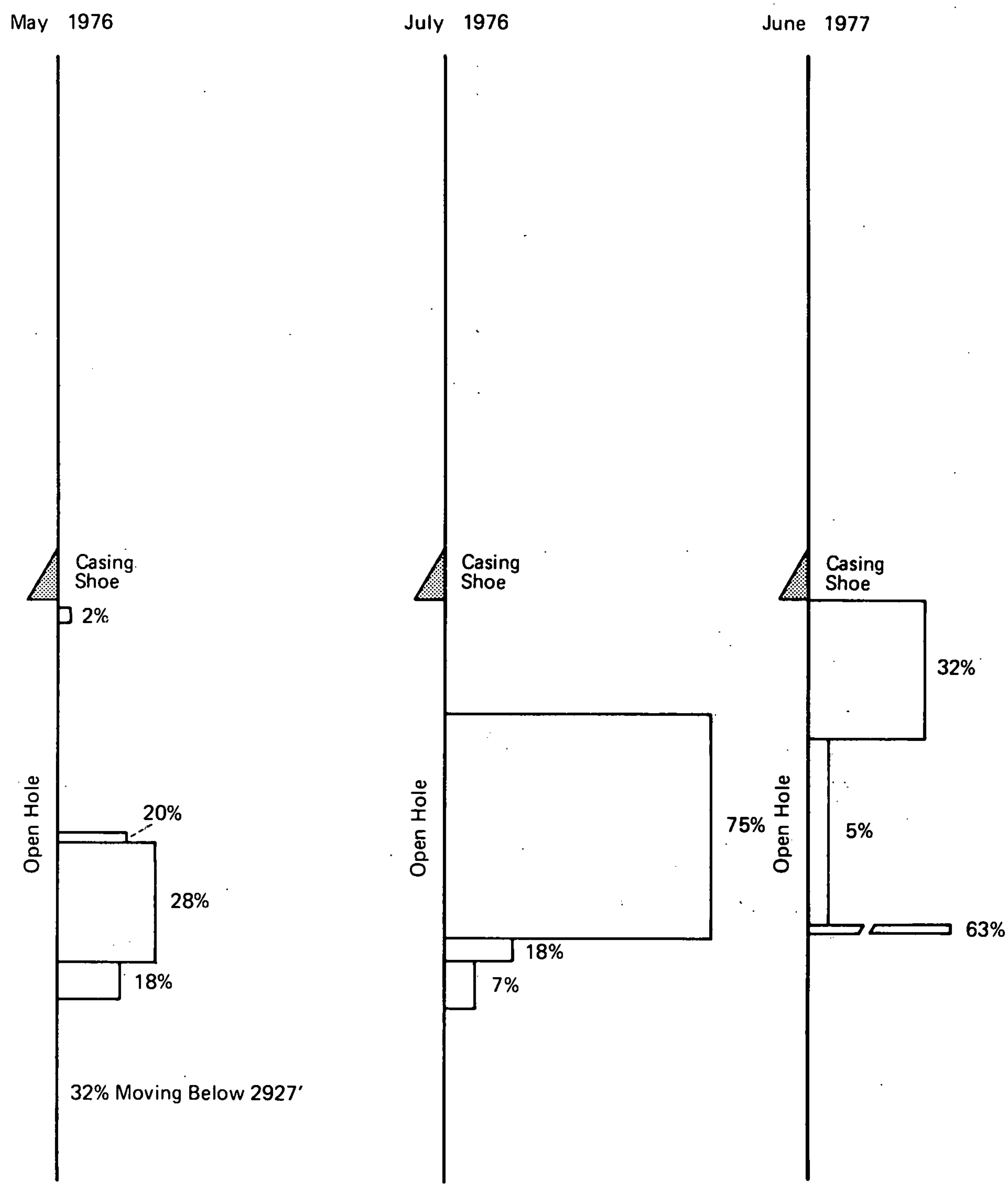
INJECTION PROFILES
HIRAM 11 WI



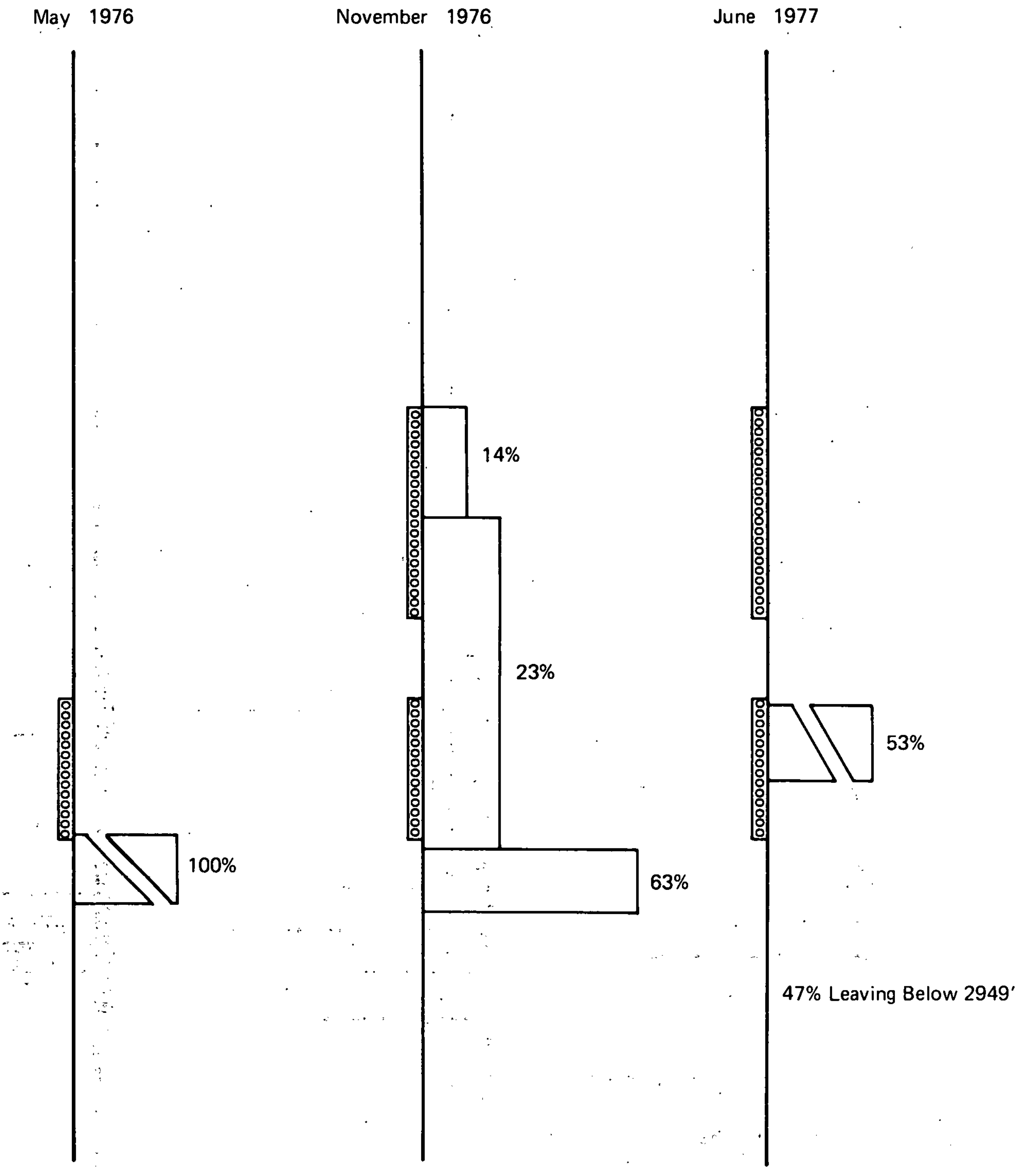
INJECTION PROFILES
HIRAM 12 WI



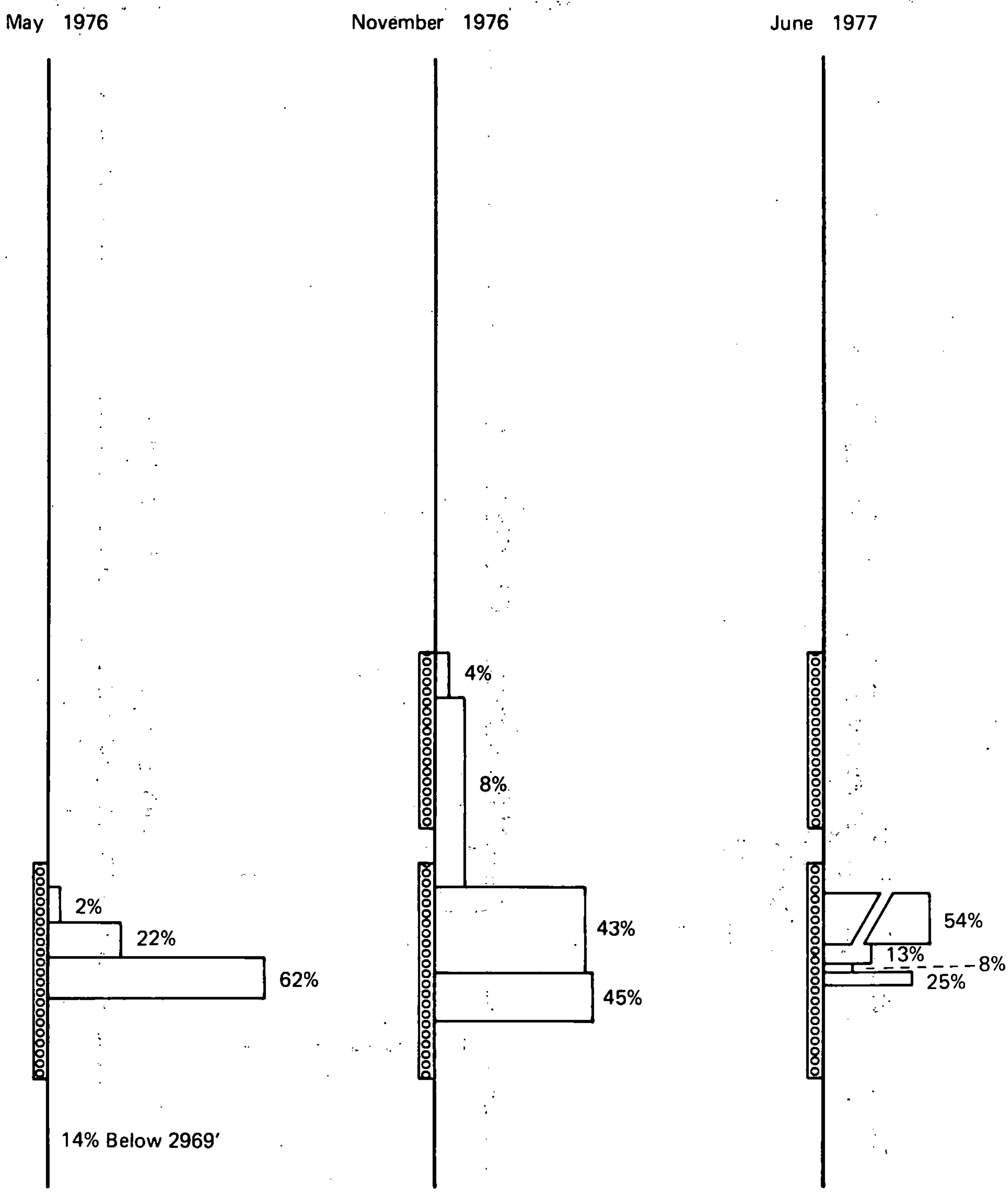
INJECTION PROFILES
HIRAM 17 WI



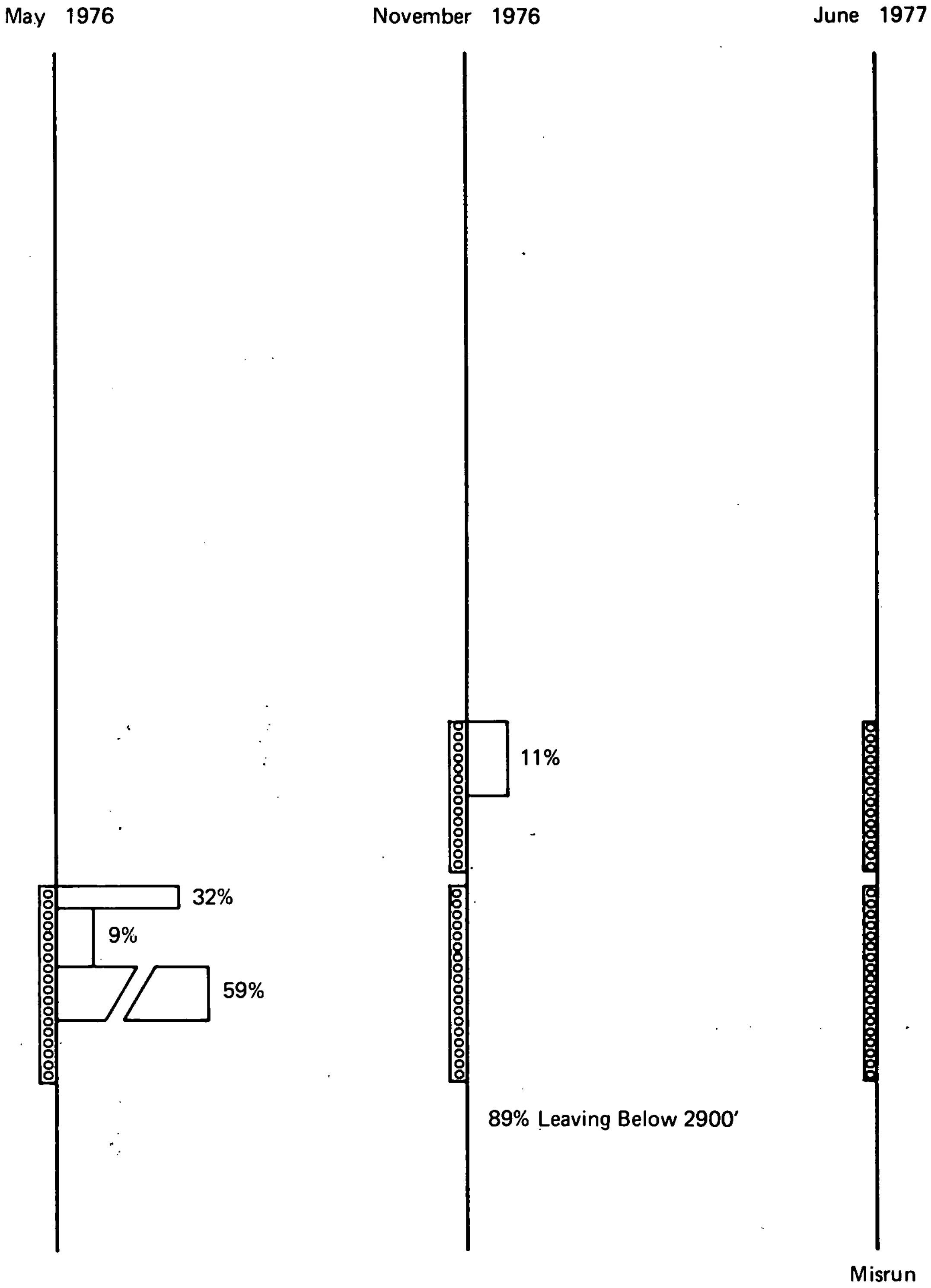
INJECTION PROFILES
PAPPIN 12 WI



INJECTION PROFILES
PAPPIN 13 WI



INJECTION PROFILES
PAPPIN 14 WI



PROGRESS REPORT ON NORTH STANLEY POLYMER PROJECT

J. W. Cunningham
Kewanee Oil Company

Presented at The University of Kansas
Second Tertiary Oil Recovery Conference, April 1977

ABSTRACT

The North Stanley Polymer Injection Project is nearing the end of the polymer injection phase. The equipment has functioned extremely well and has required a minimum of manpower and maintenance. A review of injection performance during the fresh water injection phase resulted in a revision in the polymer concentration schedule and in the application of Channelblock* treatments on high volume injection wells. An early response to the polymer has been noted. Production in April is up 145 BPD over the anticipated normal production without polymer. Although the early response is highly encouraging, it is too early to predict project economics at this date.

INTRODUCTION

The North Stanley Project was initiated under a cost-sharing contract with the Energy Research and Development Administration in June 1975. Its purpose was to determine the economic feasibility of injection of a polyacrylamide to improve waterflood performance in the latter stage of the flood's life. The project is located in Osage County, Oklahoma, near the town of Shidler (see Figure 1). It is a full scale field project involving more than 1,000 acres of productive reservoir. More description of the size and scope of the project is shown in Figure 2. The project was organized into five phases as shown in Figure 3 which is a milestone chart showing work and target completion dates. We are currently nearing the end of Phase IV, polymer injection, and are essentially on schedule.

POLYMER MIXING AND INJECTION EQUIPMENT

Figure 4 is a schematic diagram of the polymer mixing system. Fresh water enters the plant from the Ark-Burbank system and is treated with sodium hydrosulfite oxygen scavenger. At that point the stream is split with 26,000 barrels per day going to the suction of turbine pumps where the pressure is increased to $350^{\pm}$ psi. The remaining 5,000 barrels is

*Dow Chemical Company Trademark

circulated through the mixing system. Polymer is fed from a vertical bulk tank through two horizontal screws to the blenders (see Figure 5). The blenders, furnished by Dow Chemical Company, have an open top where the polymer drops into an inverted cone which has a water flow across it. Five hundred BPD of the source water are circulated through the blenders to form a slurry with the polymer. The remaining 4,500 barrels are used to dilute the slurry before it enters the suction of a duplex pump. The duplex pump increases the pressure of the polymer slurry above the discharge pressure from the turbine pumps. Final mixing and dilution occur in the pipeline delivering the polymer solution to the wells. Sufficient retention time was designed into the system to ensure that the polymer is fully in solution when it reaches the injection wells.

The plant is enclosed with a steel building to protect against adverse weather conditions. Basic responsibility for the mixing process is delegated to the lease pumper. The system has worked very smoothly with a minimum of downtime and operating problems.

RESERVOIR DESCRIPTION

Figure 8 is an isopach of the gross pay sand. The project area is the north half of the Stanley Waterflood. Comparison of the north half performance with that of the south half should provide a good evaluation of the economics of the process. Table 1 is a summary of the average properties of the reservoir. The term average properties is somewhat misleading as there is no part of the reservoir which exhibits the average properties. Figure 9 is a cross section of the reservoir showing the division of the sand into three units. The Upper Burbank section has permeabilities in excess of 1,000 md with porosity of 30%. The Lower Burbank section has permeabilitiesranging from 100 to 300 md with porosities in the range of 20%. The Bartlesville section has permeabilities of 10 md or less and porosities of 10%-13%. In addition, the Bartlesville section has a vertical fracture system which can easily be parted if injection pressures are high. Figure 10 is a graphic example of the reservoir heterogeneity. On the left is plotted the SP curve from the electric log along with the permeability profile from core analysis. On the right, the sonic porosity is plotted with the oil saturation from core analysis.

INJECTION PERFORMANCE

Due to the high overall permeability of the reservoir, both injection and producing wells have experienced high fluid volumes during the life of the waterflood. It was assumed at the start of the project that the bulk of the injection was entering the Upper Burbank section and sweeping through that section to the producing wells, thus bypassing a large portion of the reservoirs. The purpose of the polymer was to divert the injection from the high permeability section to the lower perm zones.

Prior to the start of polymer injection, a four month period of fresh water injection was required to condition the reservoir for the polymer. The fresh water was used as a tracer to identify areas of channeling between injection and producing wells, and injection profile surveys were run to establish baseline injectivity data. The following method was used to analyze the injection profile surveys. Where available, a log was constructed consisting of a gamma ray curve on the left and the permeability profile on the right as shown in Figure 11. The perforations were also plotted at the appropriate depth. Next, the injectivity per foot from the profile survey was plotted on the permeability profile, and the gamma ray curve from the injection profile survey was superimposed on the base gamma ray curve. The results are shown in Figure 12, an analysis of the injection in Fanny 5 WI prior to polymer. The method gives an indication of (1) current injection from the profile survey and (2) cumulative injection from the gamma ray deflection. Figure 12 shows clearly that most of the injection has left the wellbore through the lower permeability section, most likely through fractures. Only a small amount has gone into the upper sand, and none is currently being injected there. Figure 13 shows the value of analyzing the gamma ray curves. The profile survey on Big Eagle 9 WI shows practically all the injection leaving through the upper section. However, comparison of the gamma ray curves shows that most of the cumulative injection has gone out the lower section. The well had been acidized prior to the start of the project to open the upper zone. Figure 14 is an example of injection into an open hole completion that was completed with nitroglycerine. Based on the above three profiles, it was thought that the upper zone was being damaged either during completion or as a result of injection. However, the profile on Hiram 17 WI, Figure 15, showed that a brand new well which was carefully completed to avoid damage was injecting into the bottom zone only.

Using the injectivity analyses, the injection wells were placed in groups according to the shape of their profile. The results are shown in Figure 16. An attempt was made to correlate injection rate with profile pattern type, but no clear correlation was observed. The only factor that correlated with injection rate was the presence or absence of the high permeability sand in the wellbore. This led to the conclusion that, regardless of where the injection was leaving the well, it soon migrated to the high permeability sand before proceeding to the producing wells.

The fresh water was effective as a tracer in identifying severe channeling problems. Three wells experienced early dilution of produced water salinity. The problem was controlled in two of the wells by shutting in the injection well that was the most likely offender. As a result of the observed channeling and a desire to redistribute the injection, it was decided to apply Channelblock treatments. The location of the wells where Channelblock was applied is shown in Figure 17. A summary of the Channelblock treatments is shown in Table 2. Only one well could not be successfully treated (Pappin 12). It is the closest well to the injection plant, and the soft gel used in the treatment design could not withstand the high differential pressure the well was experiencing.

Following the Channelblock treatments and three months of polymer injection @ 600 ppm, injection profile surveys were rerun. Figure 18 shows the resuls of the surveys. Eight of the wells had changed from one profile to another. While the results were as expected, it was not possible to determine how much of the change was due to straight polymer injection and how much was caused by the Channelblock treatments.

PRODUCTION RESPONSE

Figure 19 is the production-injection history for the project. The project was initiated in June 1975. Some remedial work and a new well resulted in a brief production increase at the end of 1975. This caused a flattening of the decline curve which was not considered representative and was ignored in developing the projected decline without polymer. Polymer injection started in June 1976. There were small increases in production in September and October which held up through December. In January, production increased sharply to 660 BOPD followed by a drop to 641 in February. March and April showed small increases to 645 and 654 BOPD respectively. Figure 20 shows the location of the production response. Most of the response has occurred in the center of the project, the area that received the bulk of the injection. It should be noted in Figure 19 that the increase in production has occurred during a period of decreased injection and must be considered a result of the polymer injection.

Figures 20 and 21 are production history graphs for O'Dell 1 and Fanny 6 respectively. The top curve is water production while the oil production and water-oil ratio curves are plotted on the bottom half of the figure. In both wells, water production stayed constant or dropped while oil production increased significantly. O'Dell 1 has experienced an increase in oil production from 12 BOPD to 35 BOPD while the water-oil ratio has dropped from more than 100 to 44. Fanny 6 shows an oil production increase from 40 BOPD to 126 BOPD. The rate then dropped to 96 but has since stabilized at slightly more than 100 BOPD. The WOR dropped from more than 75 to 20.

The performance to date has exceeded the predicted response shown in Figure 19. Obviously, if the response continues to increase and exceed the prediction, the project will be profitable. However, much of the response is concentrated in two or three wells and could be short-lived. At the current time, we re encouraged by the early response and are cautiously optimistic regarding overall project economics.

TABLE 1

BASIC RESERVOIR DATA

AVERAGE POROSITY	18%
AVERAGE SPECIFIC PERMEABILITY	300 md.
INITIAL RESERVOIR PRESSURE	1200 psi.
SATURATION PRESSURE	1150 psi.
SOLUTION GOR	300
INITIAL FVF	1.18
CONNATE WATER SATURATION	30%
RESERVOIR TEMPERATURE	105° F.

TABLE 2

SUMMARY OF CHANNEL BLOCK TREATMENTS

WELL		PRIOR TO TREATMENT			CONCLUSION OF TREATMENT			NOVEMBER, 1976			VOLUME OF TREATMENT
		Injection Rate (BPD)	Pressure (psi)	Injectivity Index (B/psi)	Injection Rate (BPD)	Pressure (psi)	Injectivity Index (B/psi)	Injection Rate (BPD)	Pressure (psi)	Injectivity Index (B/psi)	
BRENNER	7 WI	1277	70	.95	500	250	.32	755	300	.48	+/-25,000
BRENNER	9 WI	3315	169	2.30	2210	270	1.44	1542	300	.98	37,180
BIG EAGLE	11 WI	3400	260	2.21	1250	325	.78	1531	320	.96	117,659
ART	7 WI	2823	170	1.95	1781	274	1.15	3204	290	2.04	42,236
HIRAM	10 WI	4936	110	3.56	2010	192	1.37	1149	310	.72	65,803
HIRAM	17 WI	4937	105	3.60	3400	275	2.20	3174	320	2.00	68,068
FANNY	5 WI	3348	167	2.30	2112	192	1.43	2418	300	1.52	25,740
GALE	14 WI	4670	125	3.36	1119	235	1.28	4505	300	2.88	75,636
PAPPIN	12 WI*	3400	310	2.17	+4000	350		2846*	250	1.89	>100,000

* Treatment unsuccessful, installed flow coil to reduce rate - December Injection Figure

FIGURE 1

LOCATION OF NORTH STANLEY PROJECT

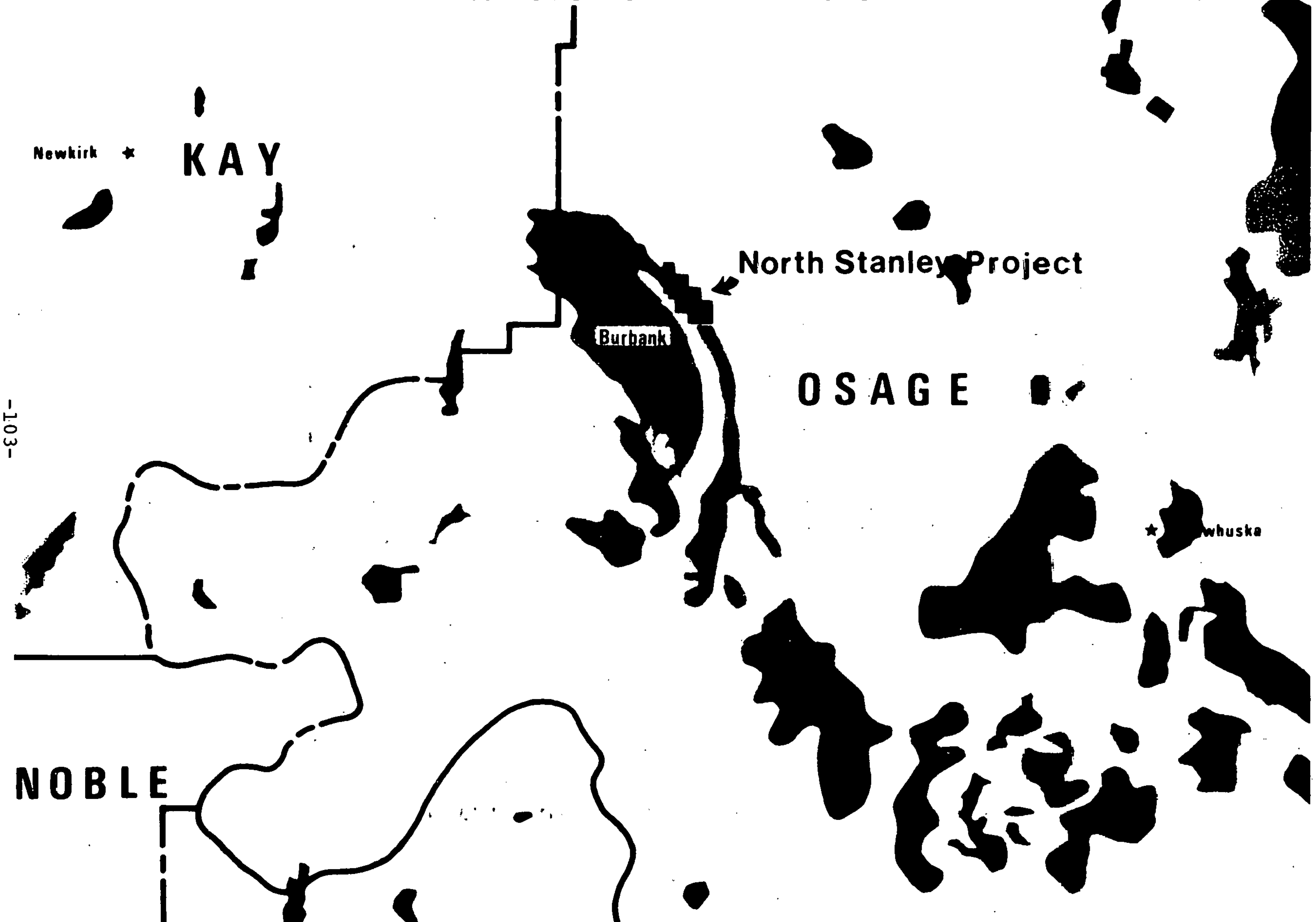


FIGURE 2

SCOPE OF THE PROJECT

1. AREA
   a. 1,560 SURFACE ACRES
   b. 1,010 PRODUCTIVE ACRES
2. VOLUME
   a. 51,000 ACRE FEET
   b. 42 MM BBLS OOIP
   c. 72 MM BBLS PORE VOLUME
3. WELLS (44)
   a. 27 PRODUCERS
   b. 17 INJECTORS
   c. 22 ACRES/WELL
4. PRODUCTION
   a. 600 BOPD
   b. 38,000 BBLS

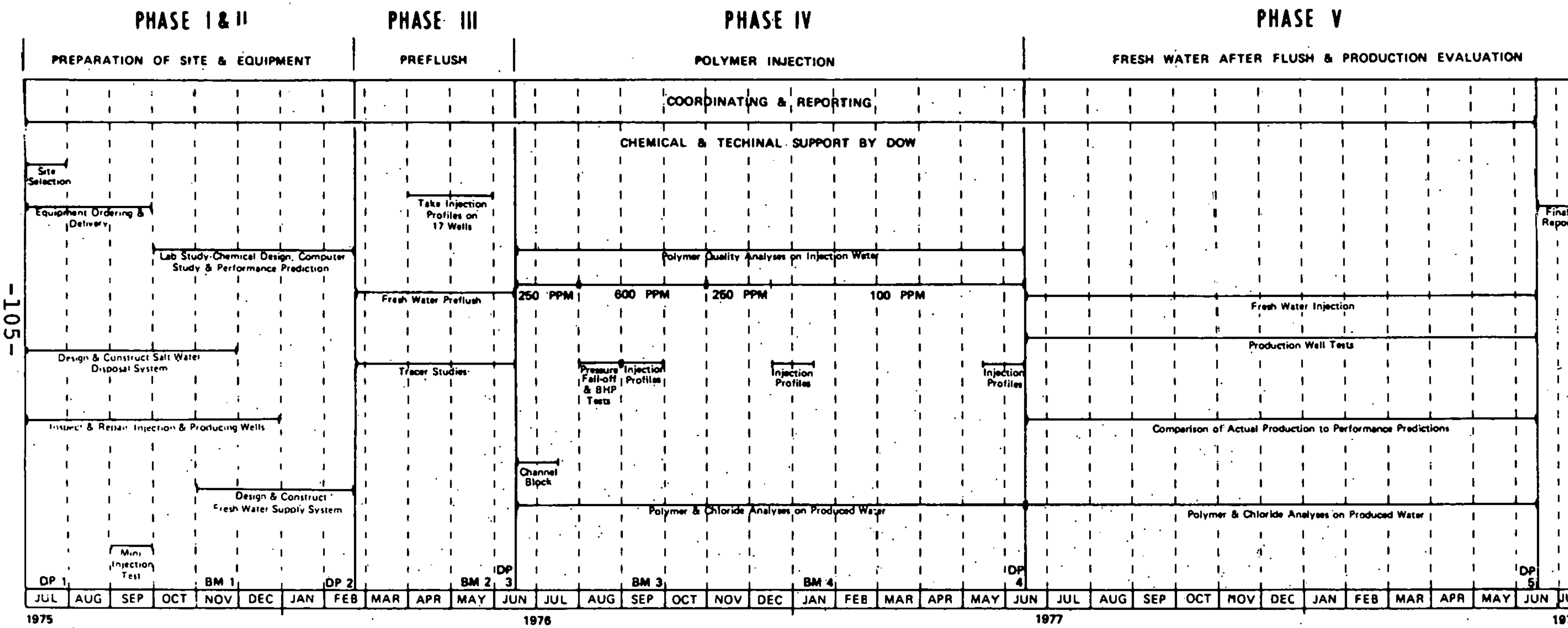
-105-

FIGURE 3

MILESTONE CHART

POLYMER INJECTION PROJECT

Controlled Water Flooding



DECISION POINT 1. IS THE TEST SITE ADEQUATE ?
DECISION POINT 2. IS THE TEST SITE READY FOR FRESH WATER INJECTION ?
DECISION POINT 3. IS THE TEST SITE READY FOR POLYMER INJECTION ?
DECISION POINT 4. IS THE POLYMER INJECTION COMPLETE ?
DECISION POINT 5. IS ADDITIONAL EVALUATION DATA NEEDED ?

BENCH MARK 1. ATTAINMENT OF ADEQUATE PRODUCED WATER DISPOSAL CAPACITY
BENCH MARK 2. COMPLETION OF INJECTION PROFILE SURVEYS DURING FRESH WATER INJECTION
BENCH MARK 3. COMPLETION OF TWO MONTHS OF POLYMER INJECTION
BENCH MARK 4. COMPLETION OF INJECTION PROFILE SURVEYS AFTER ½ OF POLYMER SLUG HAS BEEN INJECTED

Revision 1 June 10, 1976

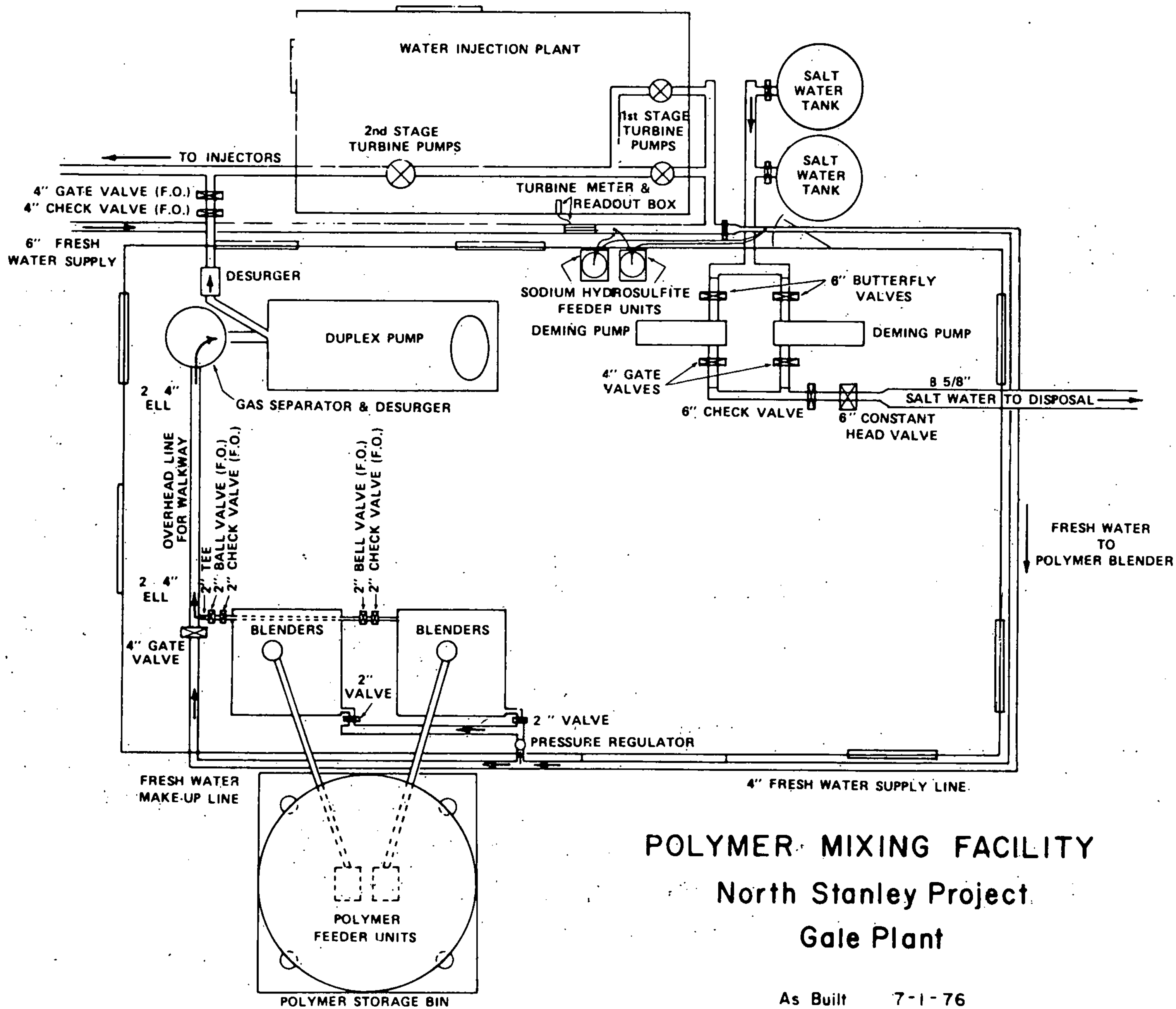


FIGURE 4
SCHEMATIC
POLYMER MIXING PLANT

FIGURE 5

POLYMER STORAGE UNIT

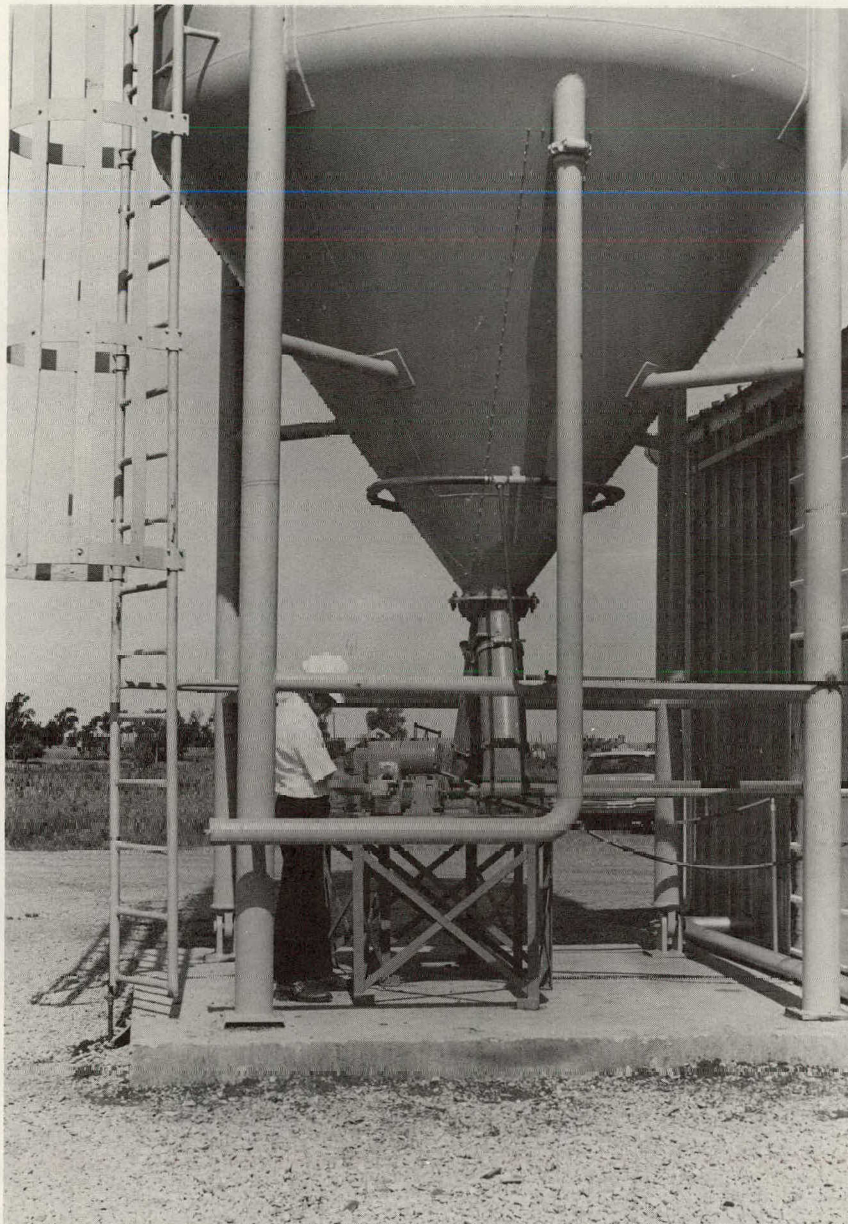


FIGURE 6

POLYMER BLENDING UNITS

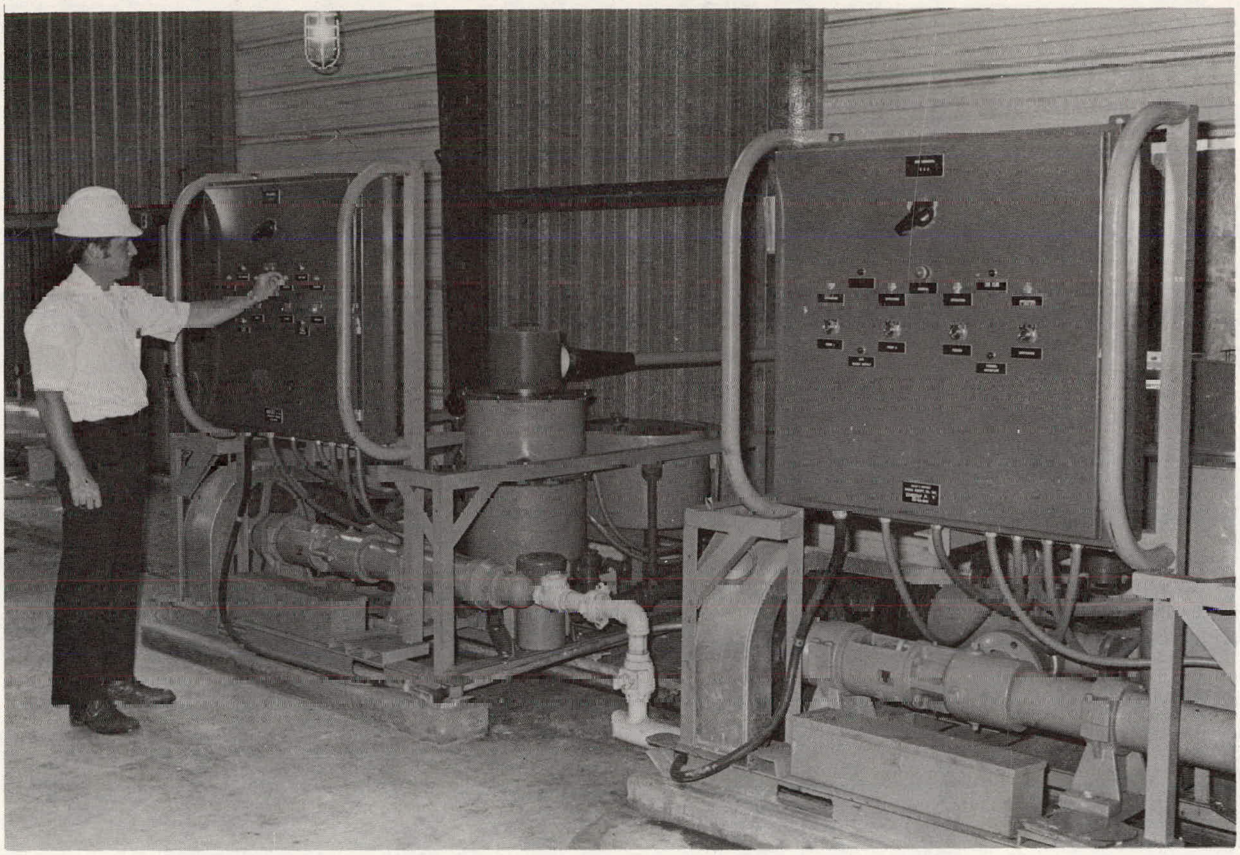


FIGURE 7

SURGE TANK AND DUPLEX PUMP

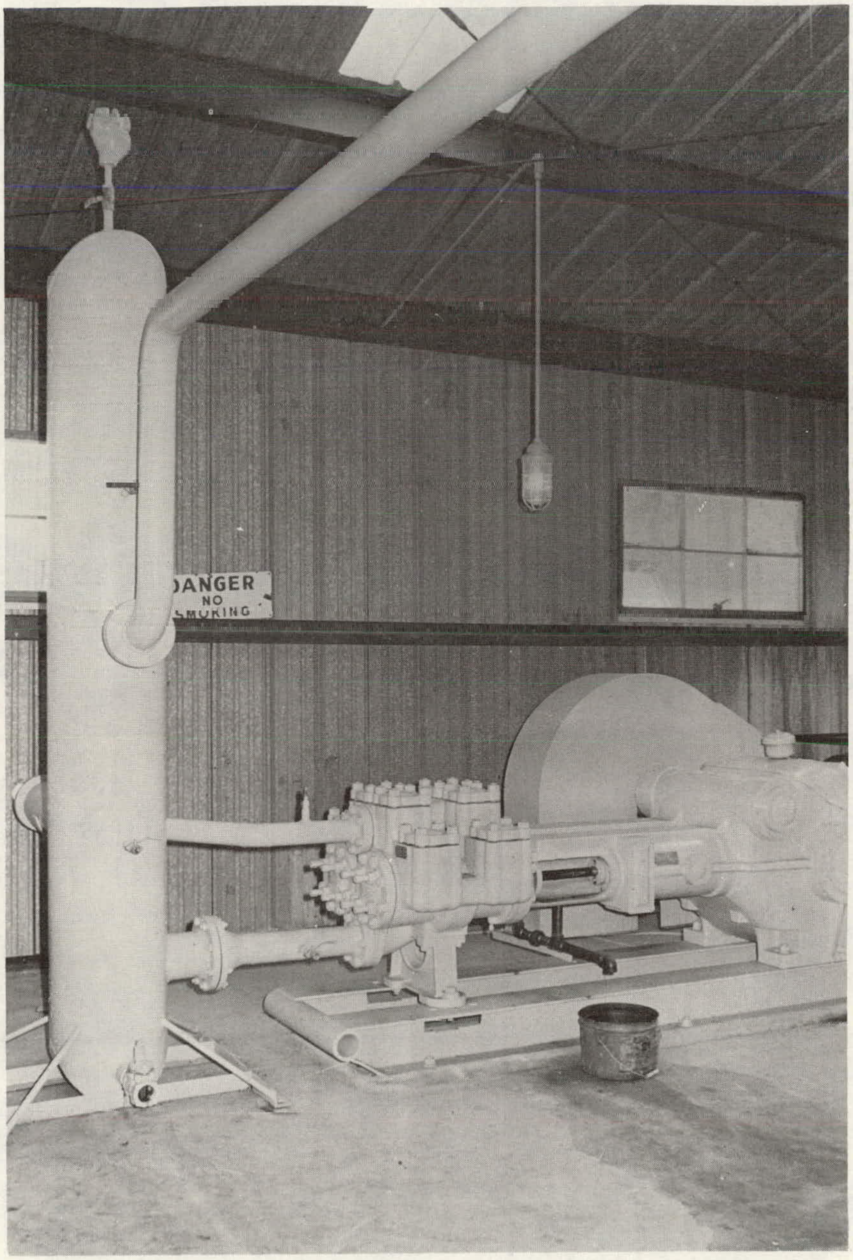


FIGURE 8

GROSS PAY SAND ISOPACH

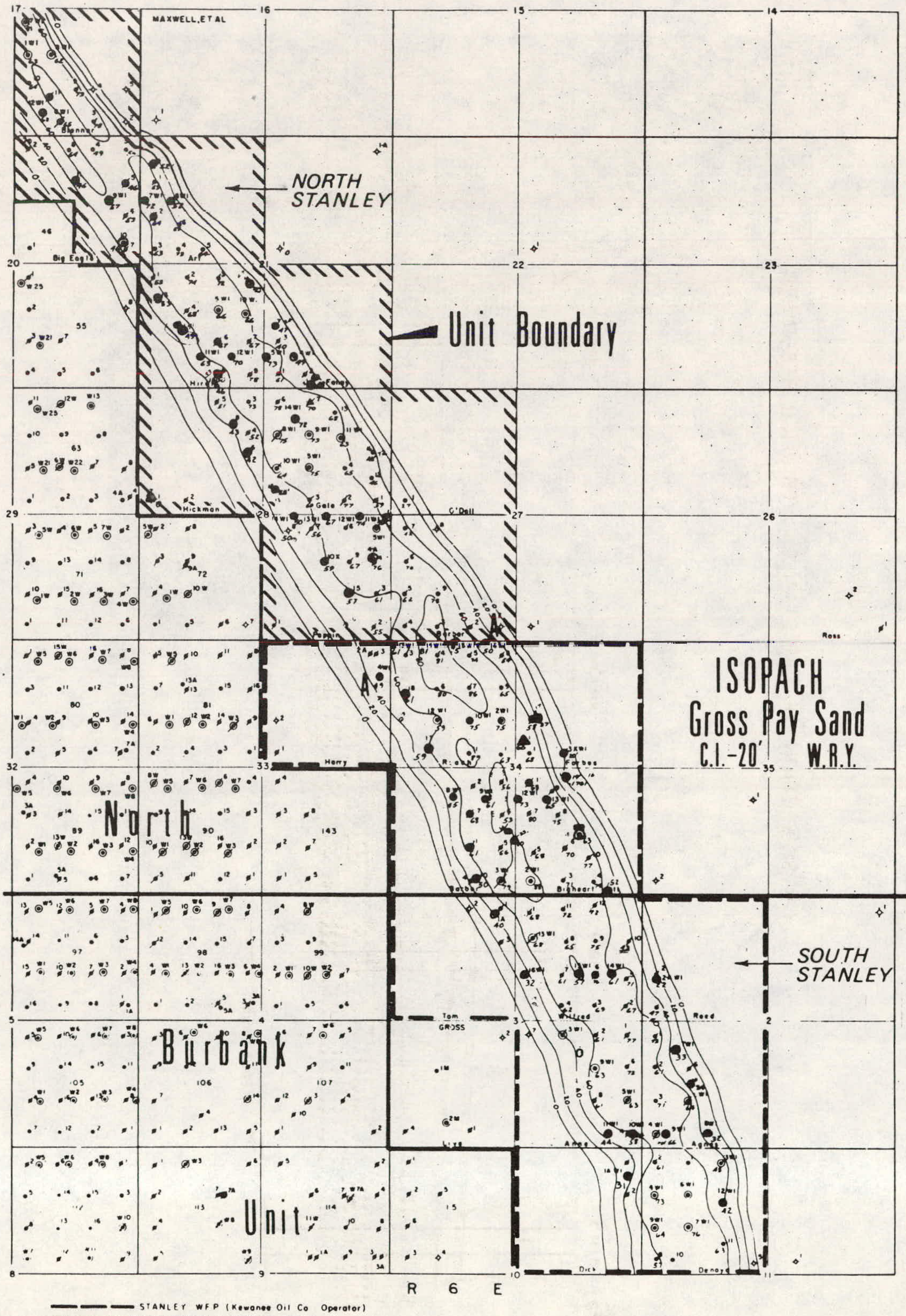


FIGURE 9

CROSS SECTION OF THE STANLEY STRINGER RESERVOIR

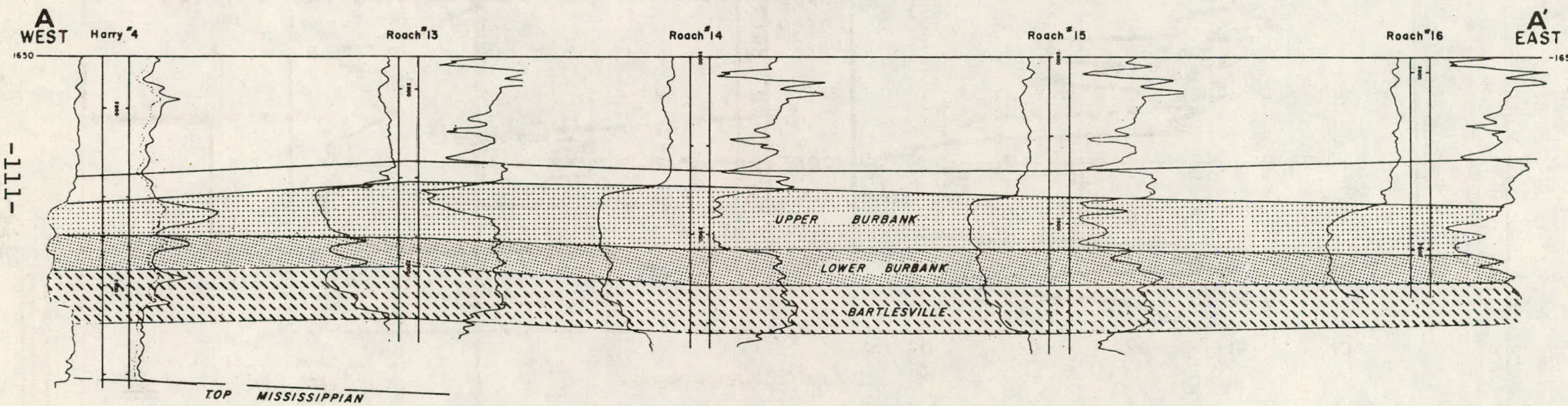
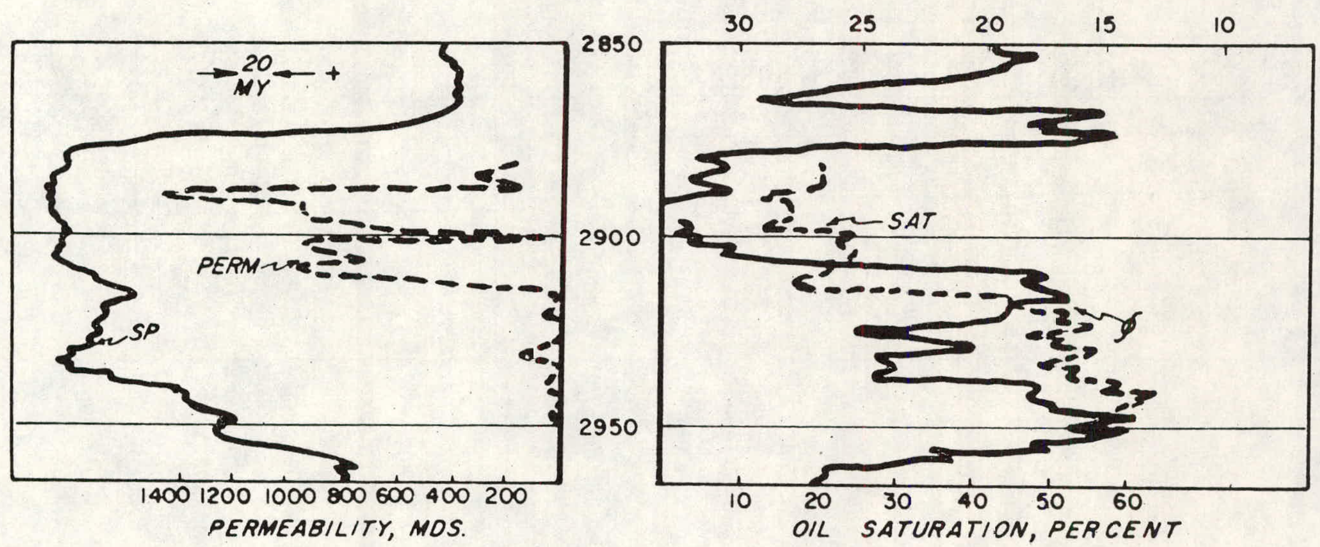


FIGURE 10

CORECRAPH AND SP - SONIC LOG

ROACH 14 WI



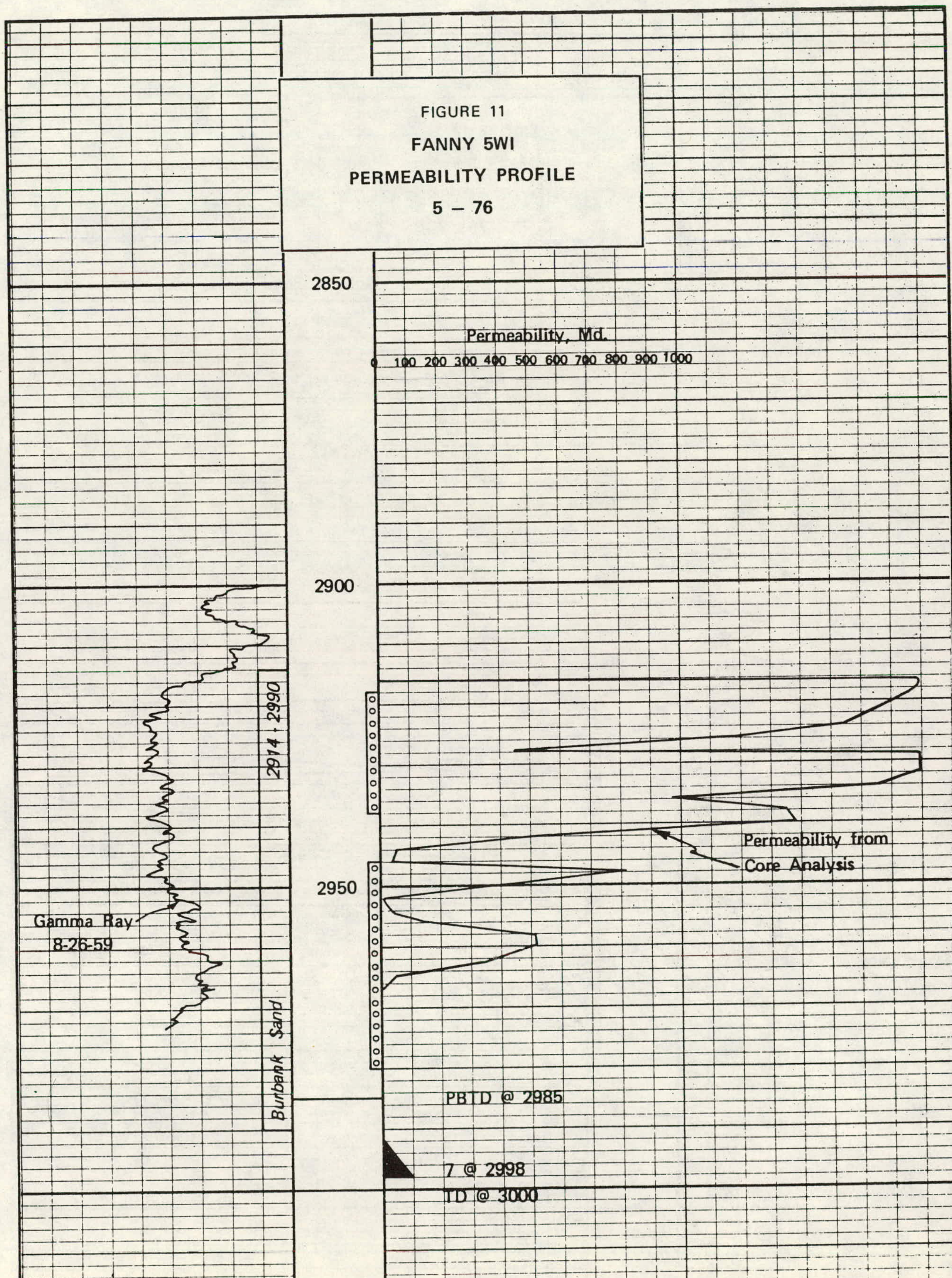


FIGURE 11
FANNY 5WI
PERMEABILITY PROFILE
5 — 76
2850
Permeability, Md.
0 100 200 300 400 500 600 700 800 900 1000
2900
2914 - 2990
Permeability from
Core Analysis
2950
Gamma Ray
8-26-59
Burbank Sand
PBTD @ 2985
7 @ 2998
TD @ 3000

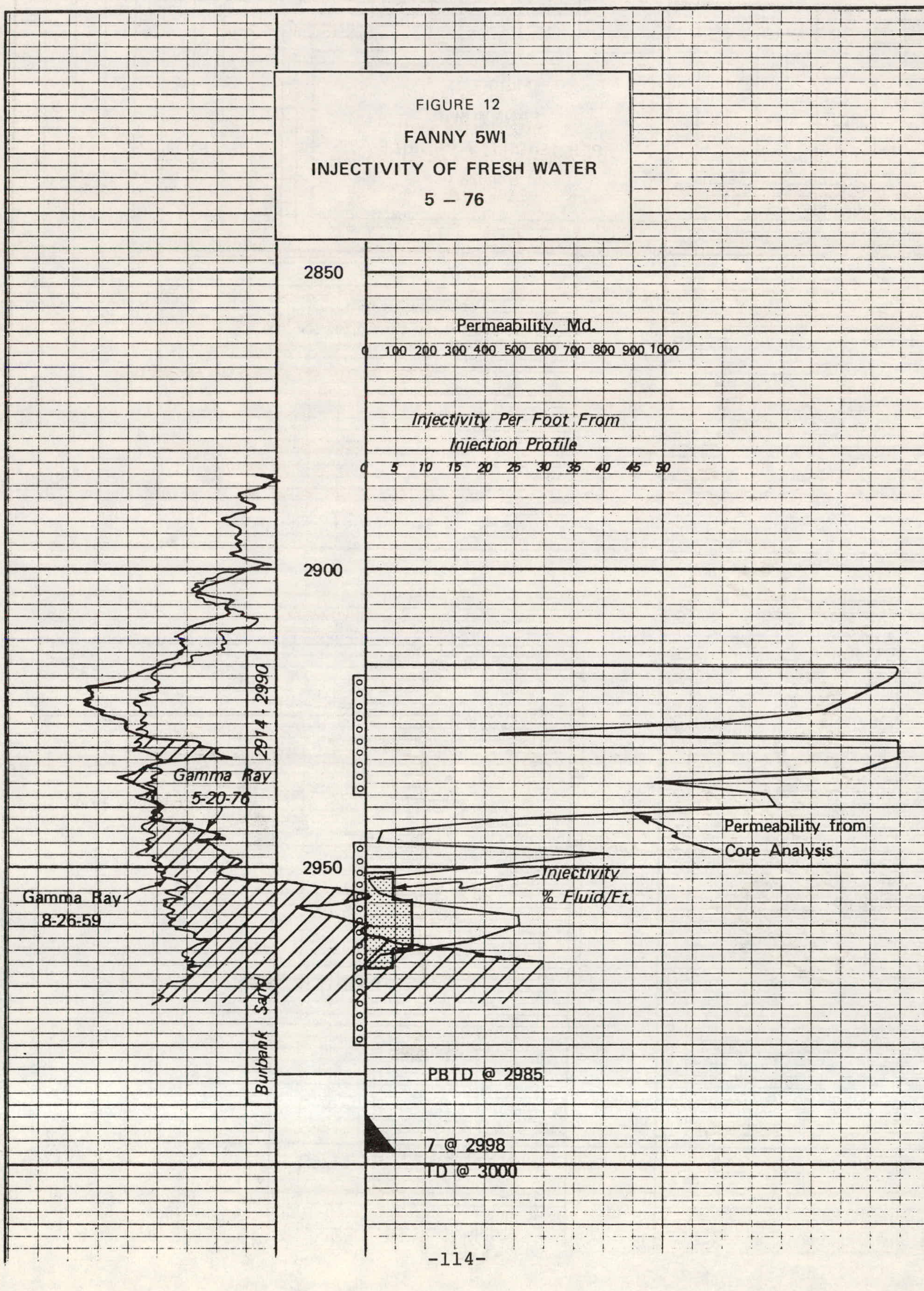


FIGURE 12
FANNY 5WI
INJECTIVITY OF FRESH WATER
5 – 76
2850
Permeability, Md.
0 100 200 300 400 500 600 700 800 900 1000
Injectivity Per Foot From
Injection Profile
0 5 10 15 20 25 30 35 40 45 50
2900
2914 - 2990
Gamma Ray
5-20-76
Permeability from
Core Analysis
2950
Injectivity
% Fluid/Ft.
Gamma Ray
8-26-59
Burbank Sand
PBTD @ 2985
7 @ 2998
TD @ 3000

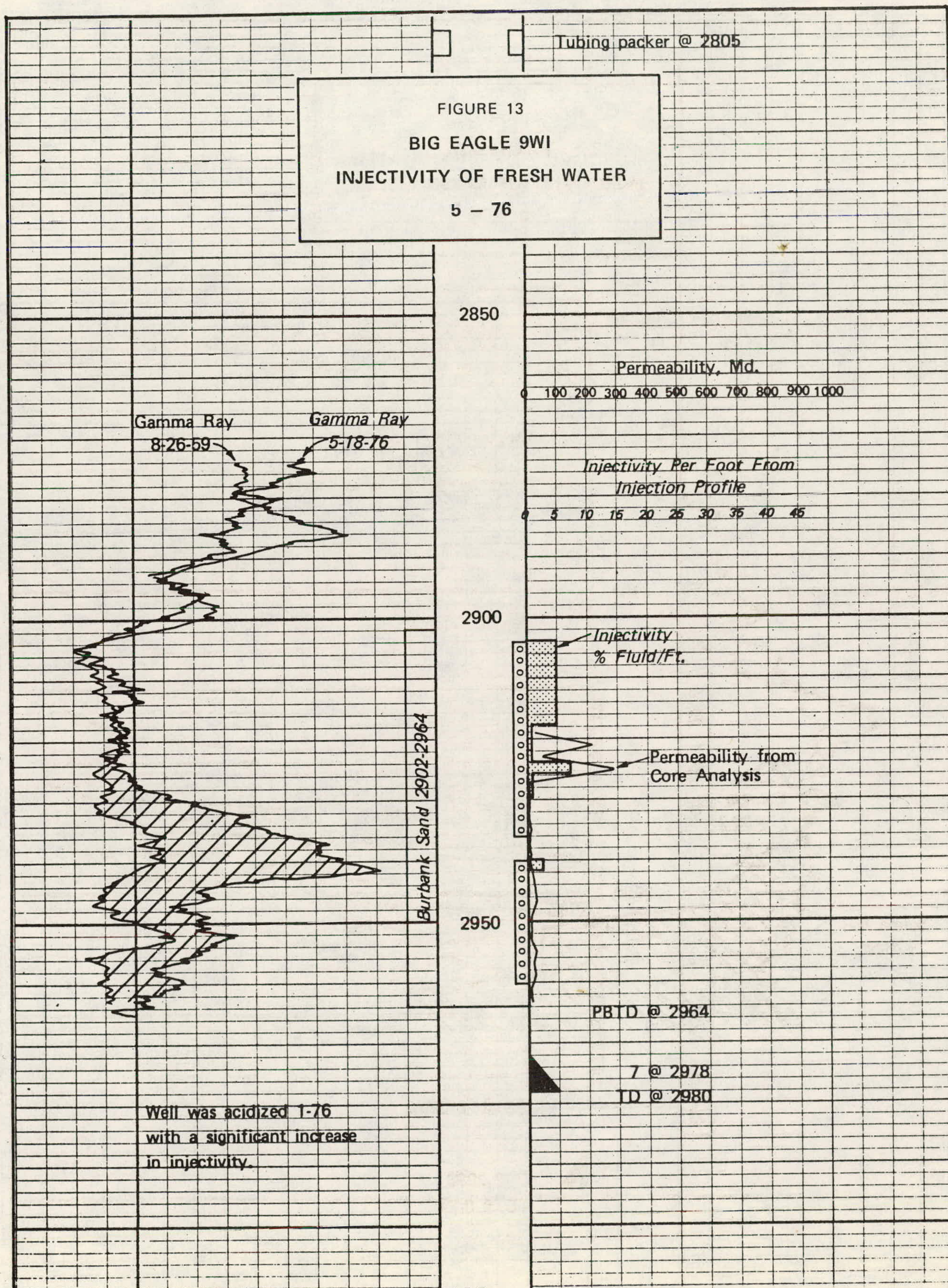


FIGURE 13

BIG EAGLE 9WI
INJECTIVITY OF FRESH WATER
5 – 76

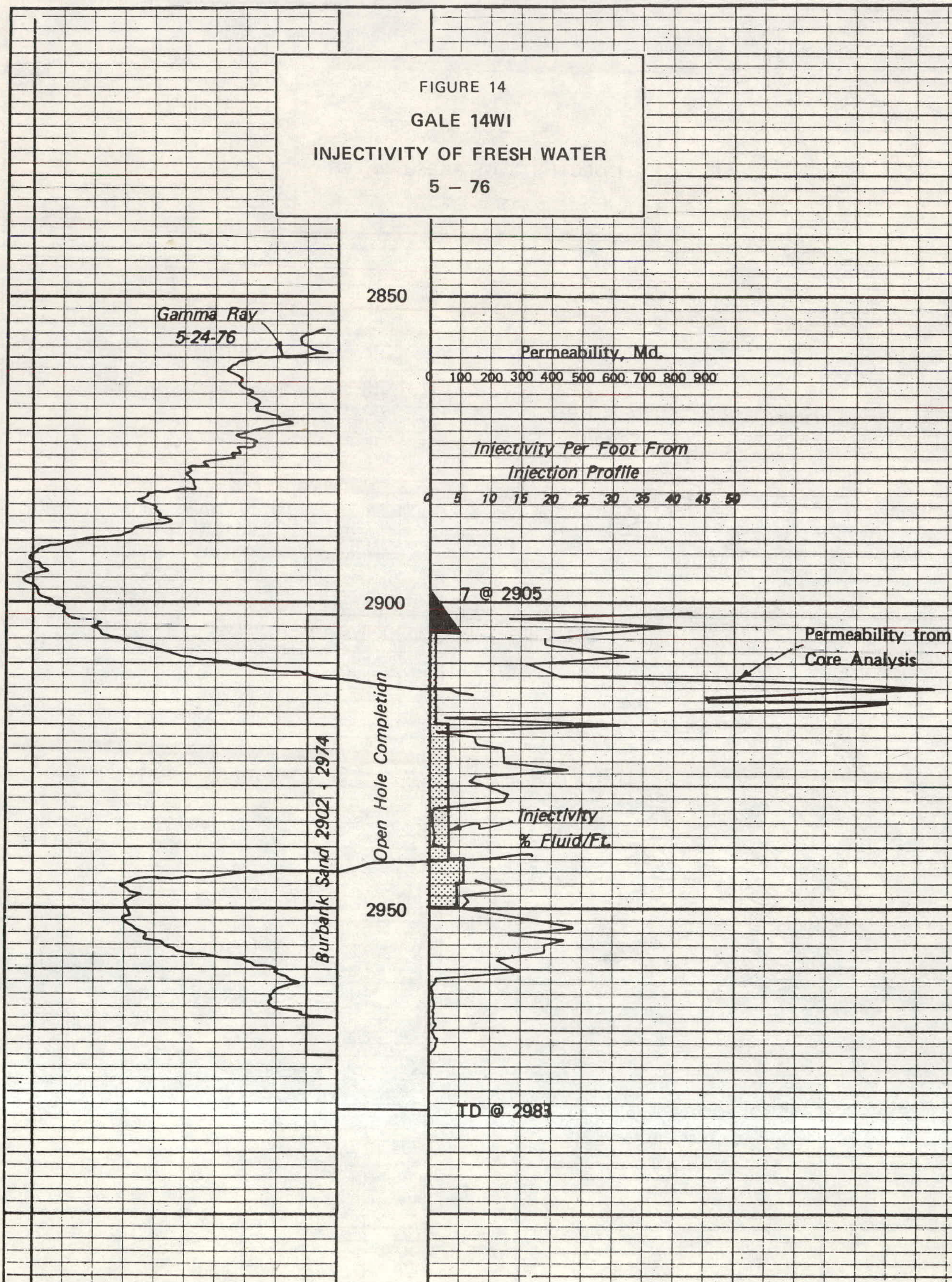


FIGURE 14
GALE 14WI
INJECTIVITY OF FRESH WATER
5 – 76
2850
Gamma Ray
5-24-76
Permeability, Md.
0 100 200 300 400 500 600 700 800 900
Injectivity Per Foot From
Injection Profile
0 5 10 15 20 25 30 35 40 45 50
2900
7 @ 2905
Permeability from
Core Analysis
Open Hole Completion
Burbank Sand 2902 - 2974
Injectivity
% Fluid/Ft.
2950
TD @ 2983

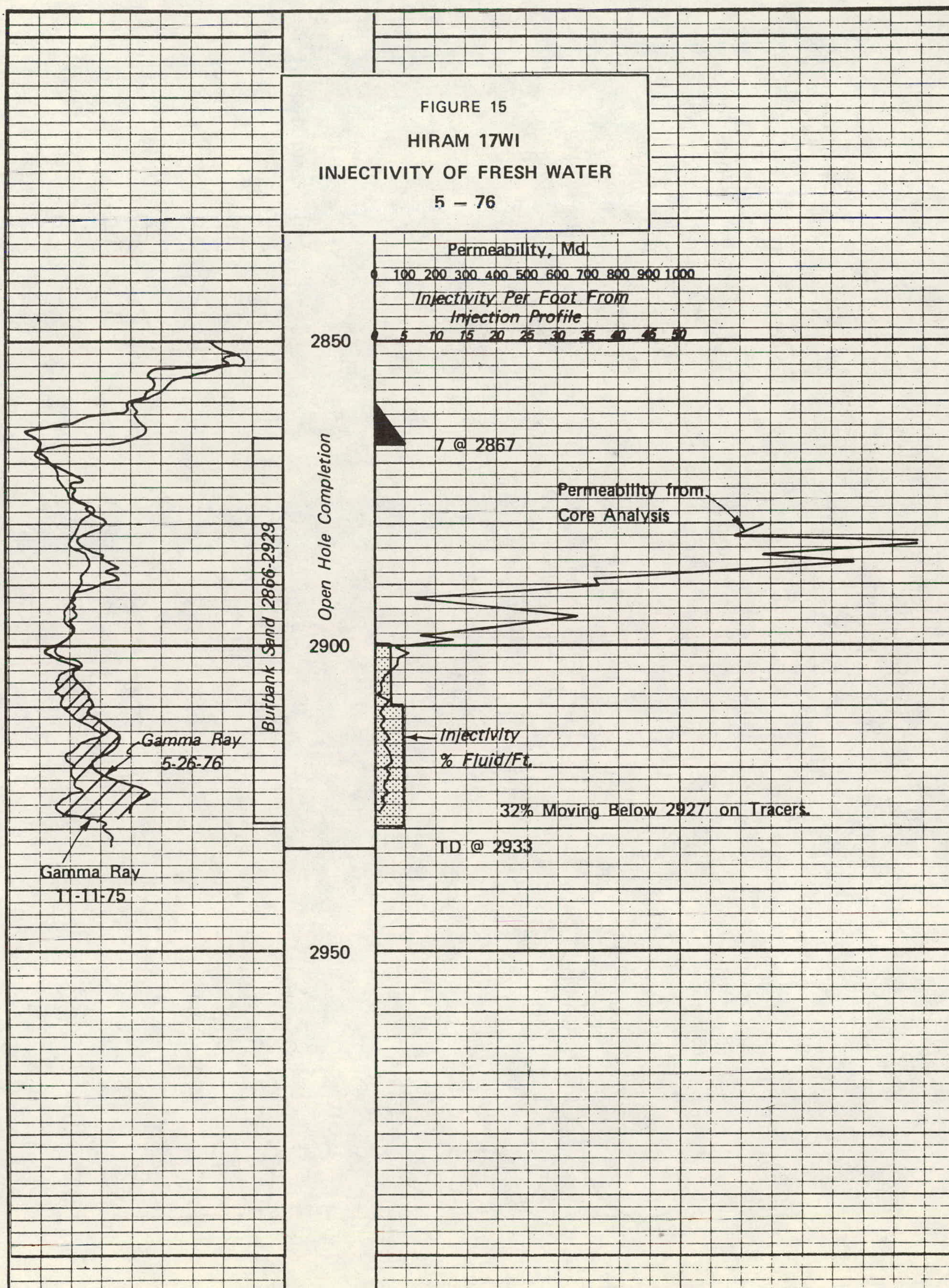


FIGURE 15
HIRAM 17WI
INJECTIVITY OF FRESH WATER
5 – 76
Permeability, Md.
0 100 200 300 400 500 600 700 800 900 1000
Injectivity Per Foot From Injection Profile
0 5 10 15 20 25 30 35 40 45 50
2850
2900
2950
7 @ 2867
Permeability from Core Analysis
Open Hole Completion
Burbank Sand 2866-2929
Injectivity % Fluid/Ft.
Gamma Ray 5-26-76
32% Moving Below 2927' on Tracers.
TD @ 2933
Gamma Ray 11-11-75

FIGURE 16

NORTH STANLEY INJECTION PROFILE PATTERNS

PRIOR TO POLYMER

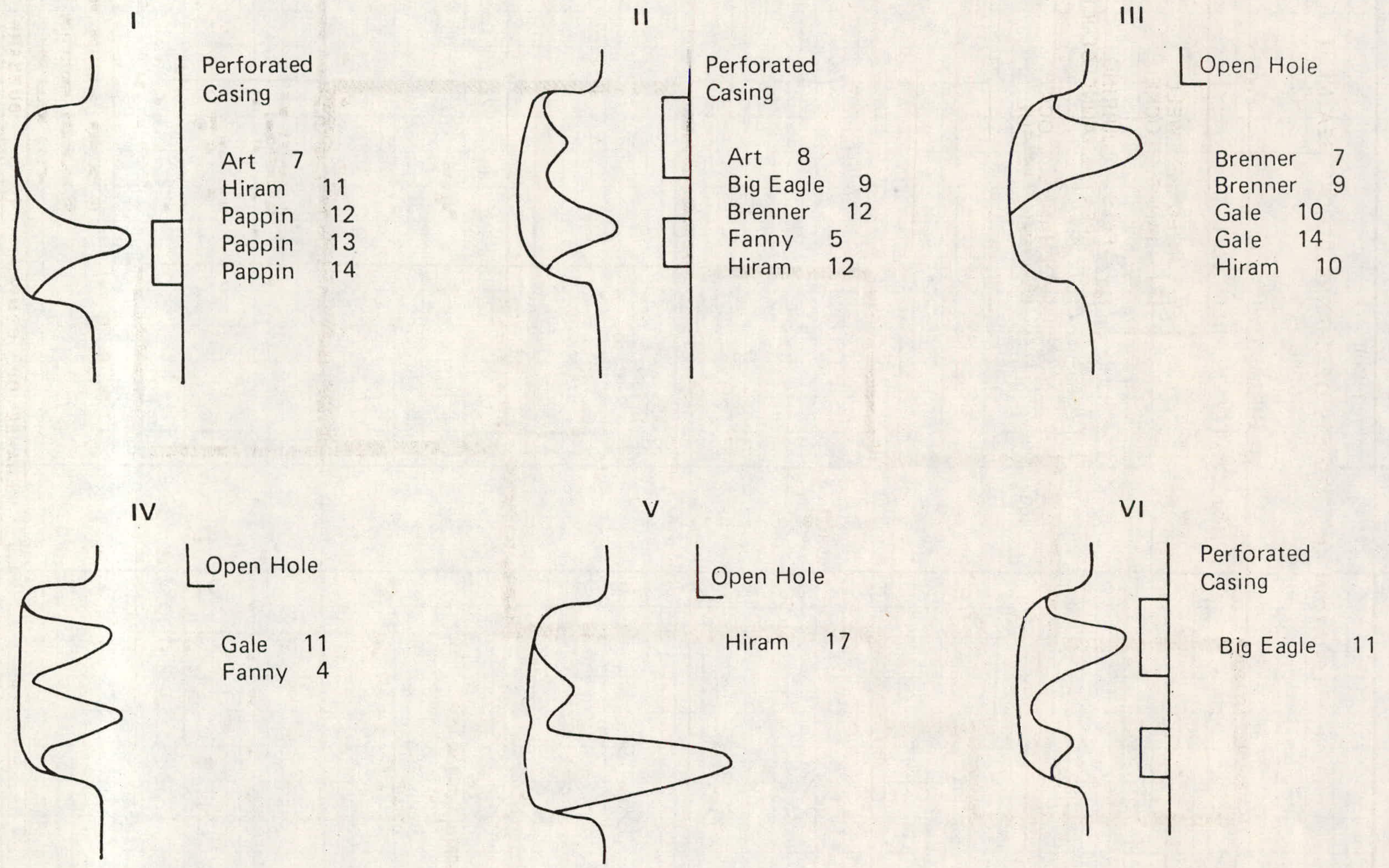
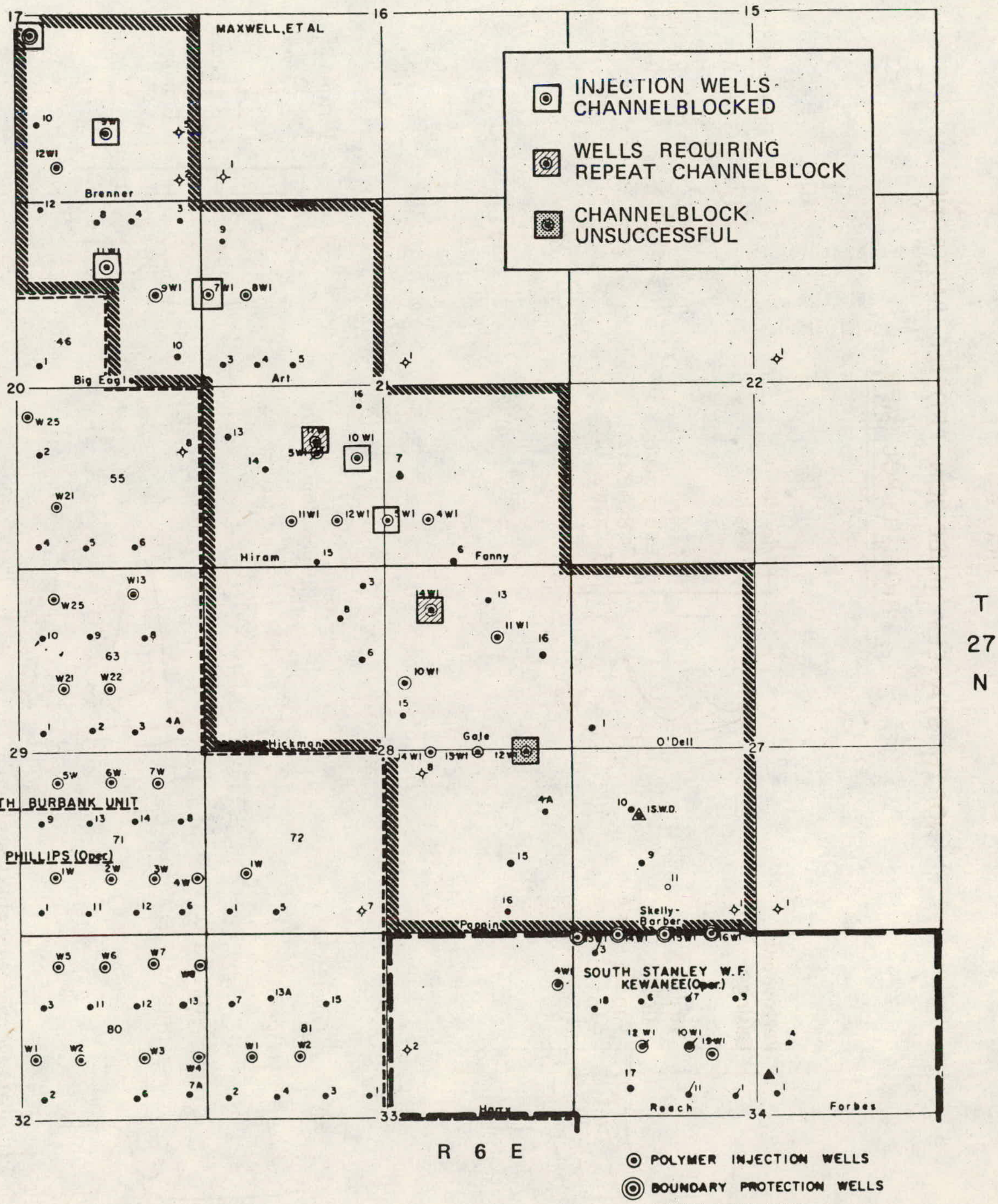


FIGURE 17

LOCATION AND RESULTS OF CHANNELBLOCK TREATMENT



LEGEND	
Oil Well	Inactive Well
Abdn Oil Well	Water Input Well
Location	S W D
Dry Hole	W S W
Gas Well	Gas Input Well
Abdn Gas Well	

KEWANEE OIL COMPANY

STANLEY POLYMER PROJECT

OSAGE CO. OKLAHOMA

DISTRICT: BURBANK

AREA: EAST AREA

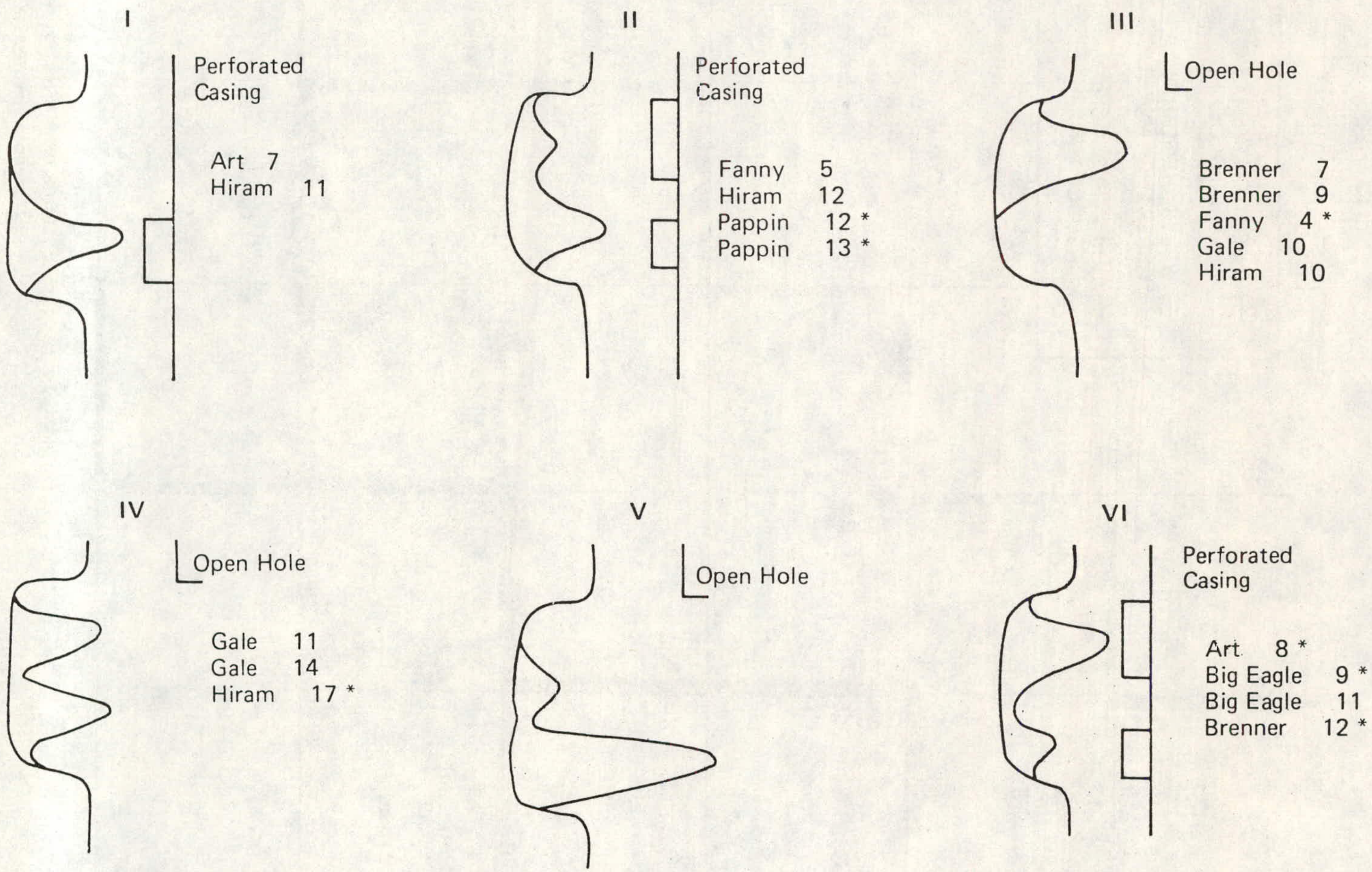
SCALE 660 0' 1320' 2640'

		REVISED	
Drawn	PLM	DATE	BY
Traced		4-1-76	MH
		5-7-76	JS
Checked		3-7-77	JS
		2-7-77	JS
Date	6-21-59	File	B-6A

FIGURE 18

NORTH STANLEY INJECTION PROFILE PATTERNS

AFTER 600 ppm POLYMER SLUG

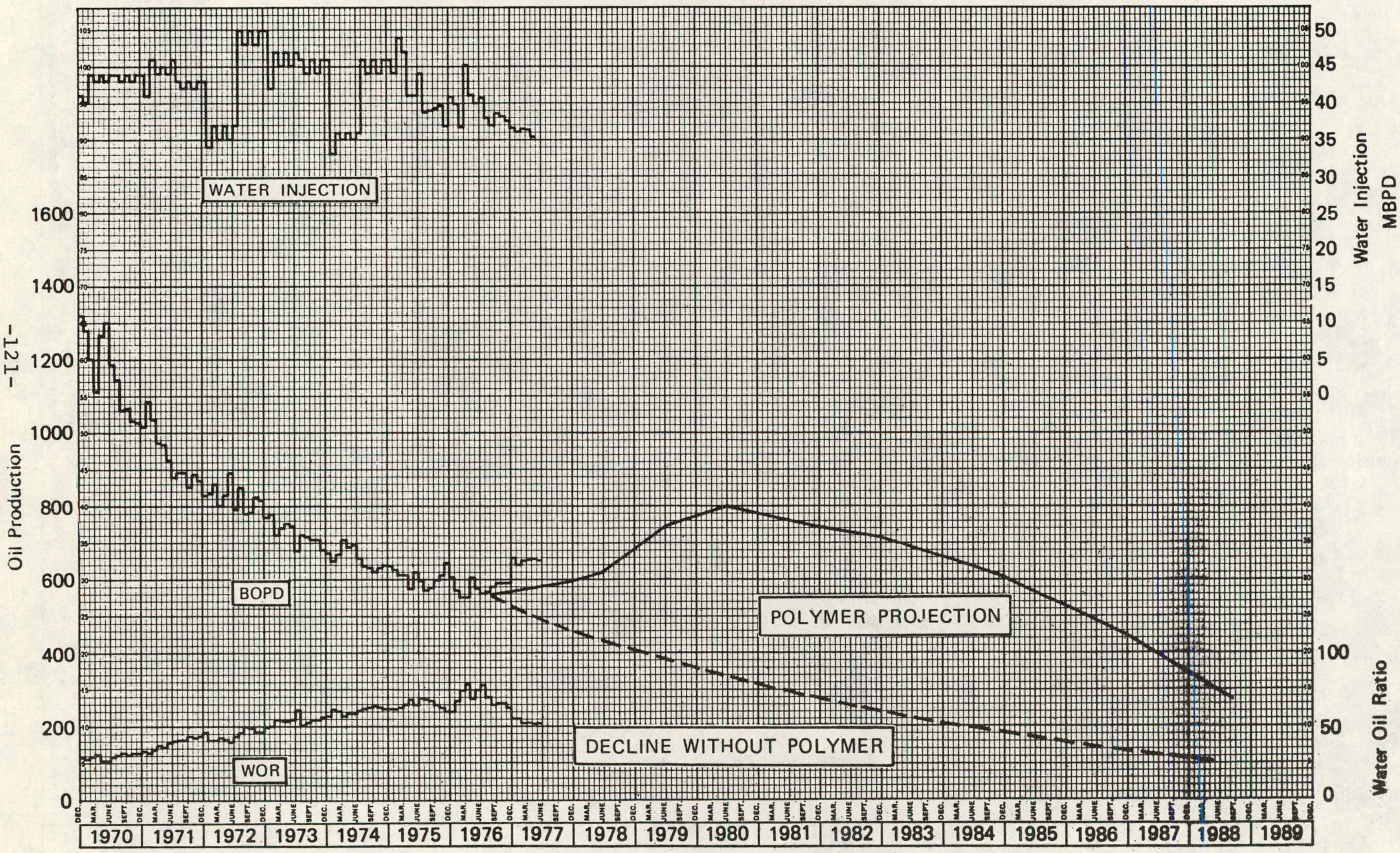


* Wells that have changed Profile Classification

Pappin 14 not classified due to low rate.

FIGURE 19

NORTH STANLEY PROJECT
INJECTION - PRODUCTION HISTORY



-121-

FIGURE 20

LOCATION OF PRODUCTION RESPONSE

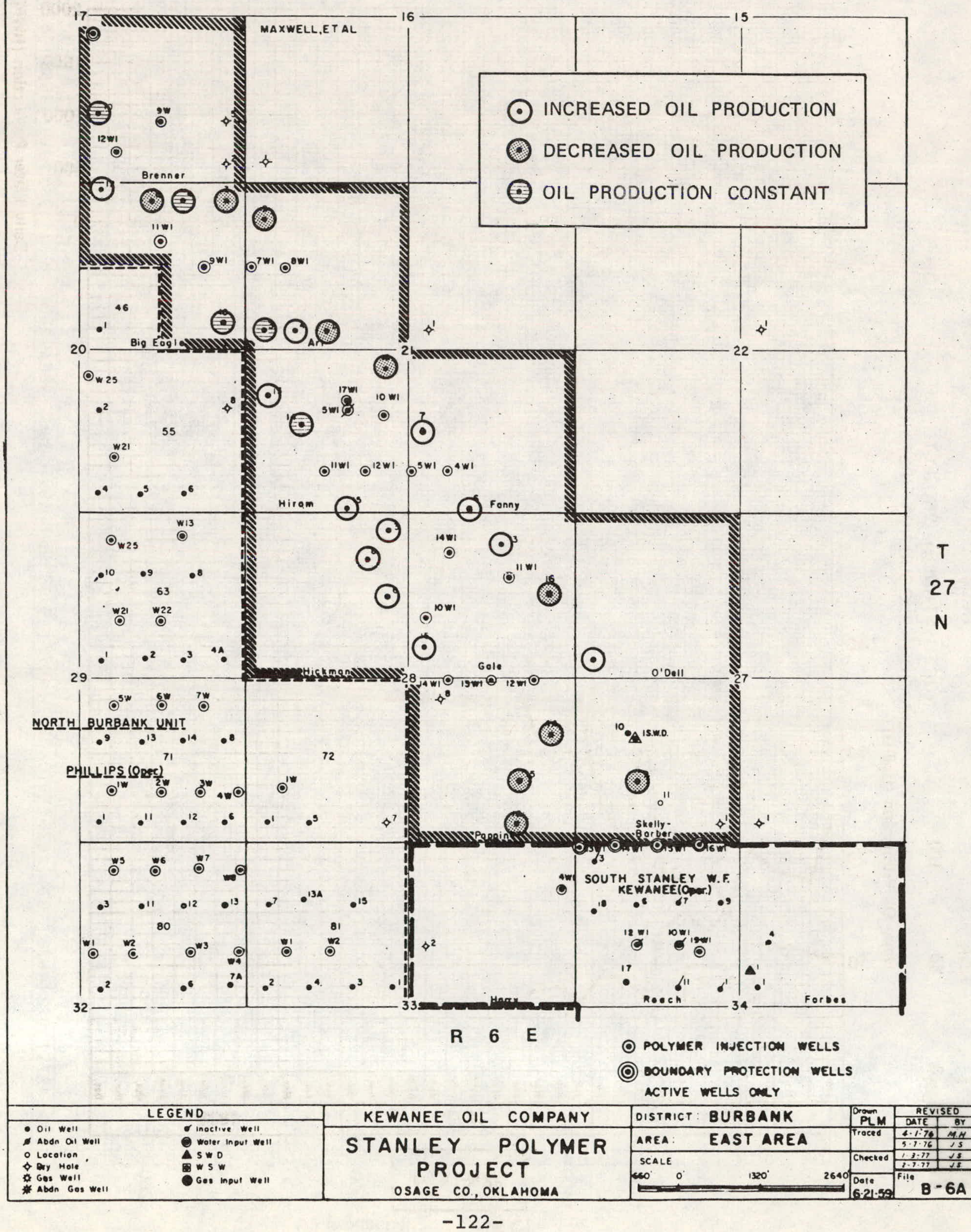
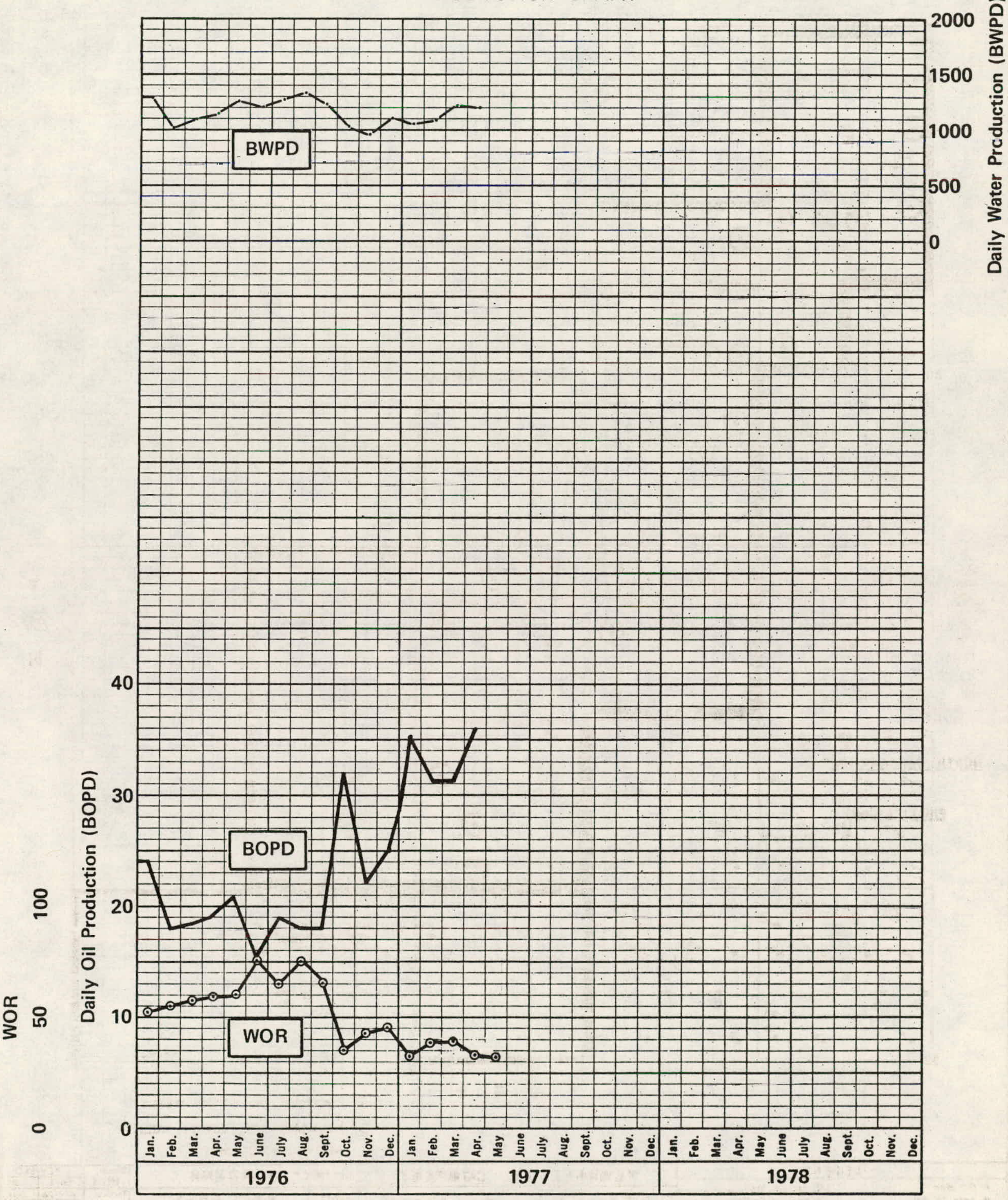


FIGURE 21

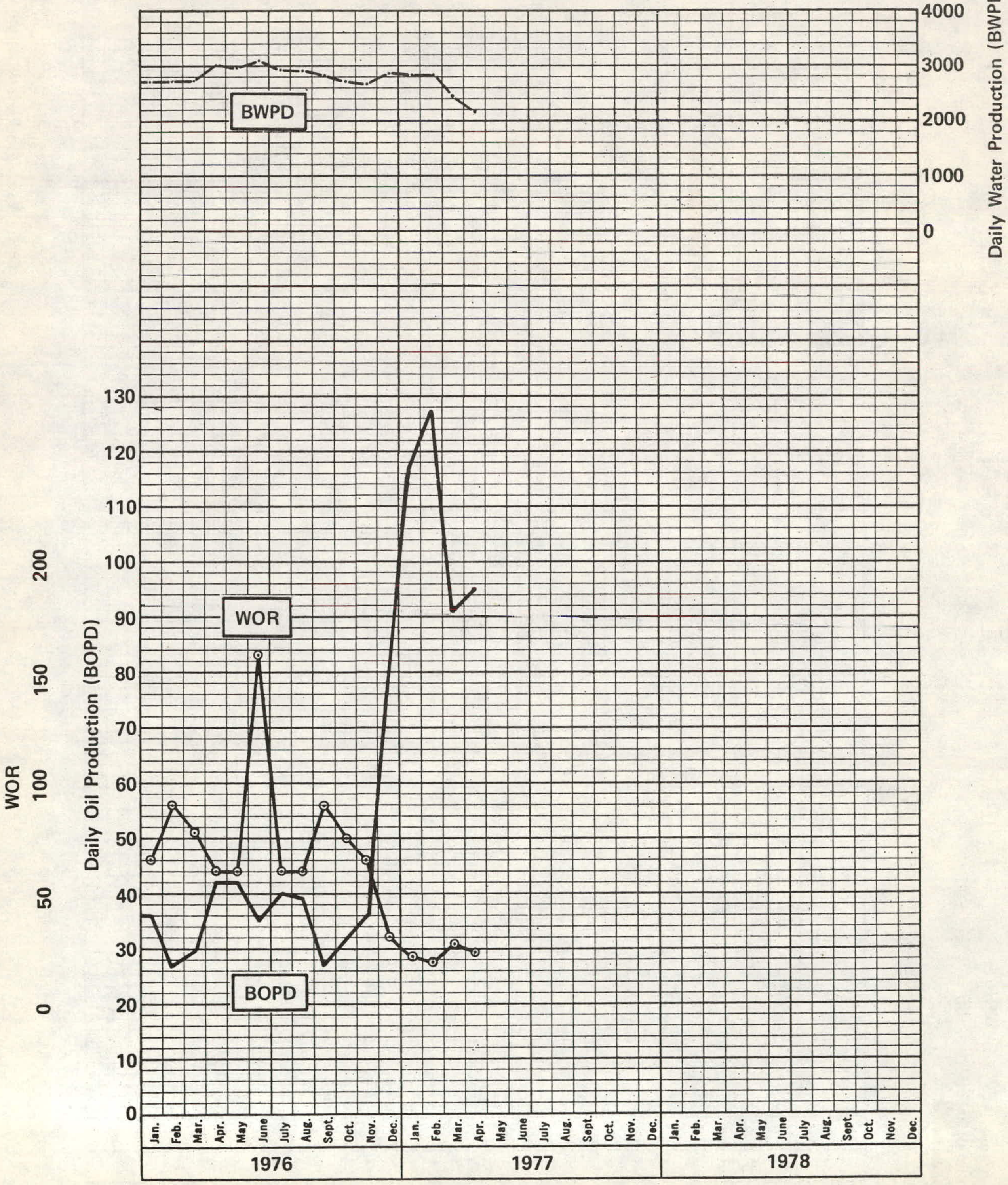
PRODUCTION GRAPH



ODELL 1

FIGURE 22

PRODUCTION GRAPH



FANNY 6