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TOPICAL REPORT

COMPARISON OF A FINITE-DIFFERENCE
SIMULATION WITH THE RESULTS FROM A
SIMPLIFIED PREDICTIVE MODEL USING DATA
FROM THE NORTH BURBANK
CHEMICAL FLOOD PROJECT

By

Mark A. Young and William D. Henline

Work performed for the
U. S. Department of Energy
Under Cooperative Agreement
DE-FC22-83FE60149



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By Mark A. Young¹ and William D. Henline²

ABSTRACT

A simulation of the North Burbank Chemical Flood Project has been completed using NICHEM, NIPER's state-of-the-art finite-difference chemical flood simulator and a simplified Chemical Flood Predictive Model.

The finite-difference simulator yielded good agreement with the field results for the oil bank breakthrough time and peak oil production rate for a particular confined five-spot in the project. The results using the Chemical Flood Predictive Model paralleled the results of the finite-difference simulator, but the oil production rates were too high. This was attributed to an inadequate treatment of surfactant adsorption in the Chemical Flood Predictive Model. A recommendation is made to base future predictions from the predictive model on calibrated field surfactant retention values using peak production rates.

INTRODUCTION

A simulation of the North Burbank Chemical Flood Project was performed by the National Institute for Petroleum and Energy Research under a contract with the Department of Energy. This work complements a previous evaluation (1) of the project and is an extension of simulation work done by Phillips Petroleum Company in 1979 (2). The objectives of this work were to: (A) Simulate project performance and extract important process parameters thereby improving

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current understanding of the chemical flood process; and (B) Compare the simulation results using a state-of-the-art finite-difference simulator with the chemical flood predictive model (3) (CFPM) to address possible improvements in CFPM.

The North Burbank Unit (NBU) Tertiary Recovery Pilot Test was a cooperative project funded jointly by Phillips with its partners and the Department of Energy. Contract No. E-(34-1)-0021 was awarded to Phillips Petroleum Company on May 12, 1975. This was a cost-sharing contract of 39 months duration with government funds amounting to \$3,402,042.

The North Burbank Unit (figure 1) was selected as a good reservoir for a large surfactant-polymer tertiary pilot test. It had been under successful waterflooding operations for 25 years and production had declined to a stable, relatively low level that would quickly reflect any increased recovery. The reservoir still contained some 400 million barrels of sweet 39° API oil that offered significant incentive to develop a technology for recovering substantial additional reserves.

The North Burbank reservoir is a large sand body consisting of many overlapping sand bars deposited along the southern shore of the Cherokee Sea of Pennsylvanian Age. Over the unit, the sand averages 47.2 feet in thickness with porosity of 16.8% and permeability of about 50 md. The sand is rather strongly oil-wet. The formation is characterized by east-west fracturing such that the effective permeability in the east-west direction is five times as great as that in the north-south direction. This results in a preferential east-west movement of injected fluids. For this reason, the waterflood was generally developed by injecting water in east-west rows of wells and producing alternate rows of wells.

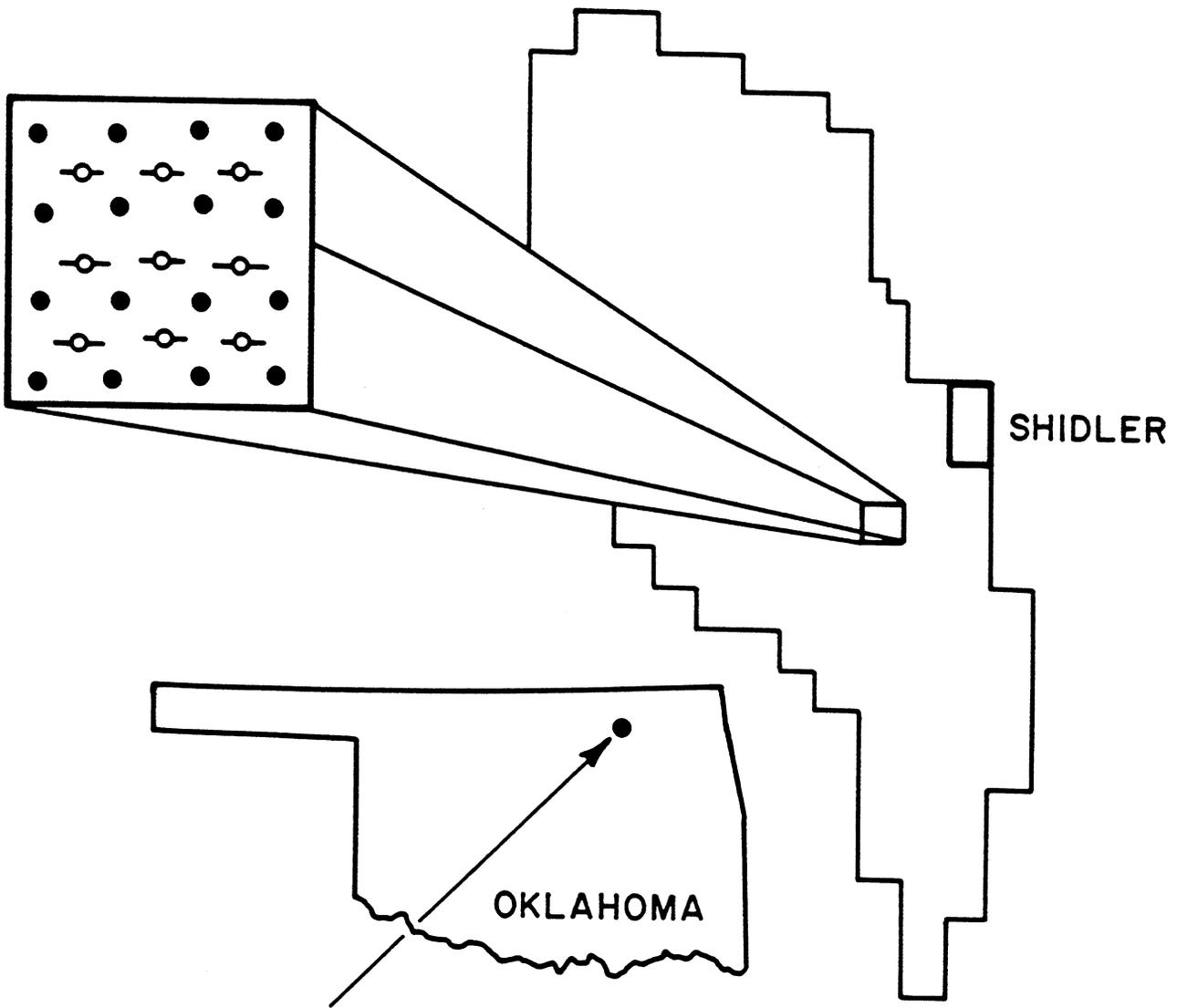


FIGURE 1. - North Burbank Tertiary Recovery Pilot.

NBU Tract 97, a 160-acre quarter section, was selected as the site for a pilot test of the surfactant-polymer flooding technology because it was one of the areas of highest oil recovery. More than 3,000,000 barrels of oil had been recovered by a combination of primary recovery and waterflooding. It was considered that those reservoir qualities which resulted in high primary and secondary recovery would also offer the best opportunity for tertiary recovery. In addition to its high oil recovery, Tract 97 had good reservoir rock qualities of thickness, porosity and uniformity of permeability. It also had excellent balance between the volume of water injected and the volume of fluids produced. This implied that there were no thief zones and the reservoir could be considered volumetric in this area.

A pattern of nine inverted 10-acre-five-spots was selected for the pilot test on Tract 97. The 10-acre well spacing permitted project evaluation in a reasonable period of time, and provided maximum reservoir data and process control of injection and production rates, but kept project capital investment at a reasonable level. The pilot pattern is shown in figure 2. This inverted 5-spot pattern minimizes the chemical requirements, as compared to a conventional 5-spot pattern, yet provides 40 acres of virtually confined pattern area protected from off-pattern influences. Reservoir pressures surrounding the pilot tract were controlled by controlling injection and production rates to ensure no loss of the chemical fluids injected into the pilot tract.

The ultimate oil recovery from the North Burbank Project was approximately 300,000 barrels, which is about one-half of the initial prediction made by Phillips. Although oil recovery was less than expected, sufficient additional

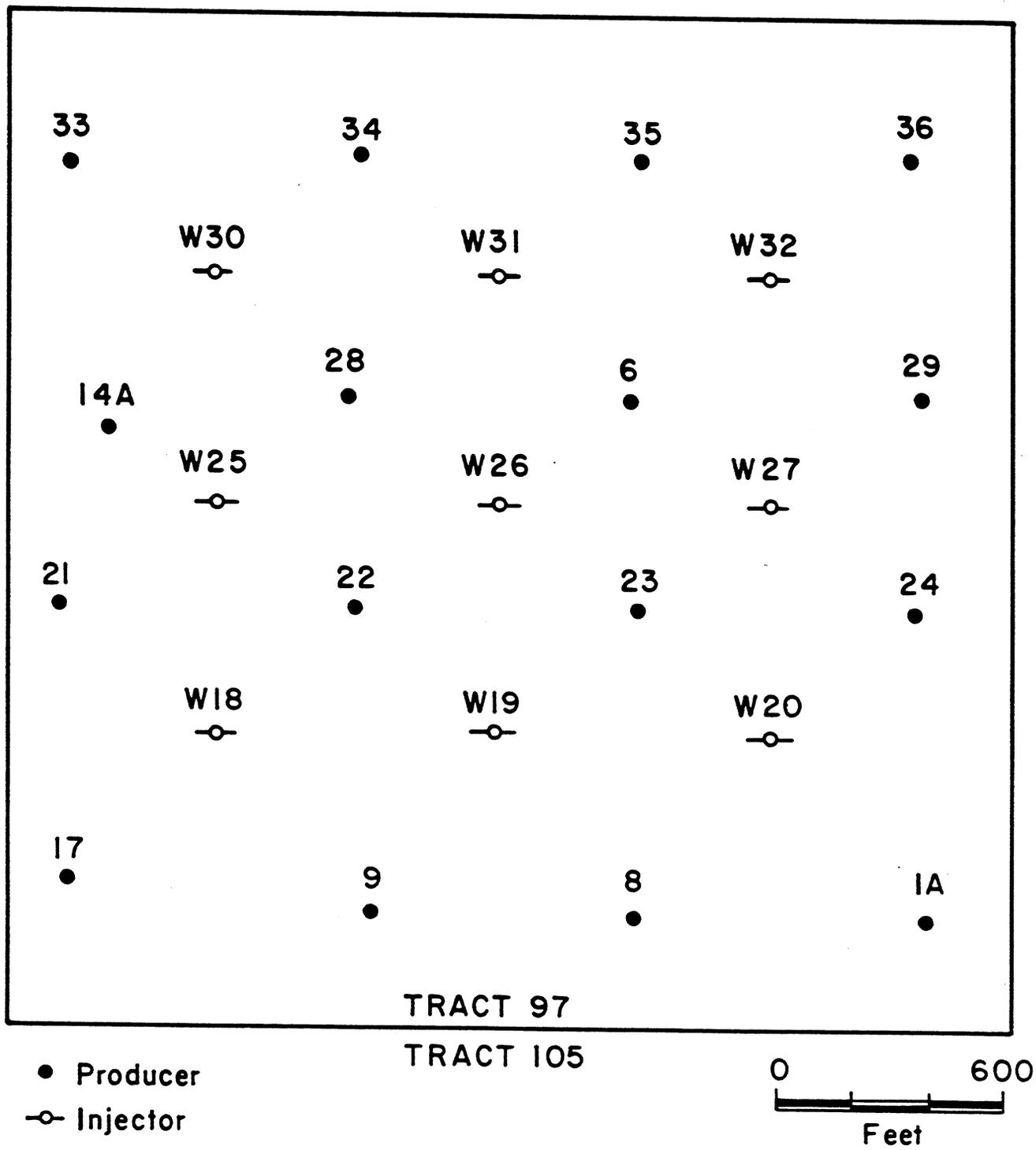


FIGURE 2. - Pilot Pattern NBU Tract 97.

oil was recovered to consider the project technically successful. The lower-than-expected oil recovery was attributed principally to high surfactant losses, and as described below, is born out in the simulations conducted in this study.

To achieve the objectives of this study it was necessary to have both a detailed, numerical finite-difference simulator and a simplified chemical flood predictive process model. The finite-difference simulator used in this work was derived from a chemical flood simulator developed at the University of Texas by Dr. Gary Pope and Akhil D. Gupta. This computer code was selected because of its low acquisition cost and excellent surfactant-water-oil phase equilibrium model, as well as adsorption and polymer loss phenomenology. The code was upgraded and modified at NIPER for use on the DOE Perkin-Elmer 3230 computer. The Chemical Flood Predictive Model used in this work was based on the program developed by A. Goldberg, H. Price and G. W. Paul under a contract with the DOE. Several improvements have been incorporated into this model since the first version was developed. The latest version was used in this work, and was supplied by M. Ray of the DOE. In the following sections, the North Burbank pilot test is described in more detail, and the application of the numerical simulation to calculate specific aspects of the project are outlined. Results obtained are used to evaluate the efficacy of using the DOE Predictive Chemical Flood Model in such projects.

DESCRIPTION OF NORTH BURBANK CHEMICAL FLOOD PROJECT

The following discussion describes the geological and engineering data that served as a basis for developing the simulation approach used in this study. This information was derived from a series of annual reports on the project (4, 5, 6, 7).

The North Burbank Chemical Flood Project consisted of a sequence of fluid injections starting with a fresh water preflush, and followed by a saline (1.5wt% NaCl) preflush, surfactant, mobility buffer (polymer), fresh water drive (Ark-Burbank water) and Burbank Brine injection. This fluid injection sequence is given in table 1 together with the start date and pore volumes injected for each stage.

The basic process conditions used in this field project were selected on the basis of both laboratory studies and field data. Design of the injection fluid properties and conditions relied heavily on laboratory results.

The average concentrations of the components of the surfactant slug were 6.04 percent Witco TRS 10-410 sulfonate, 2.92 percent isobutyl alcohol and 0.888 percent sodium chloride. At the start of surfactant injection, the NaCl concentration was 1.473 percent. Early laboratory work with dead Burbank oil showed effective displacement from cores with the NaCl concentration at 1.5 percent. Later work with live Burbank crude showed minimum interfacial tension could be achieved with 0.9 percent NaCl. Thus, the NaCl concentration was reduced in the field test. The sulfonate concentration was increased from the original design value of 5 percent to approximately 6 percent to allow for higher losses expected in the reservoir due to higher adsorption and incomplete preflushing. Laboratory work revealed that the phase-volume behavior of the surfactant-brine-oil system was not very sensitive to changes in the amount of TRS 10-410 used over the range from 5 to 6 percent. The mobility buffer (polymer injection stage) began with a polymer concentration of 2,500 ppm. Polymer was a solution of Betz Hi-Vis polyacrylamide and has the viscosity versus concentration relationship shown in figure 3. Polymer solution concentration was gradually graded downward to 100 ppm. The polymer

TABLE 1**INJECTION SCHEDULE FOR 90-ACRE PILOT FLOOD**

Fluid Injected	Date for Start of Injection	Pore Volume Injected (%)
Fresh Water Preflush	12-1-75	24.2
Salt Water Preflush	4-19-76	15.8
Surfactant	8-2-76	6.0
Mobility Buffer	9-15-76	52.0
Ark-Burbank Water	1-16-78	60.0
Burbank Brine	8-12-79	-

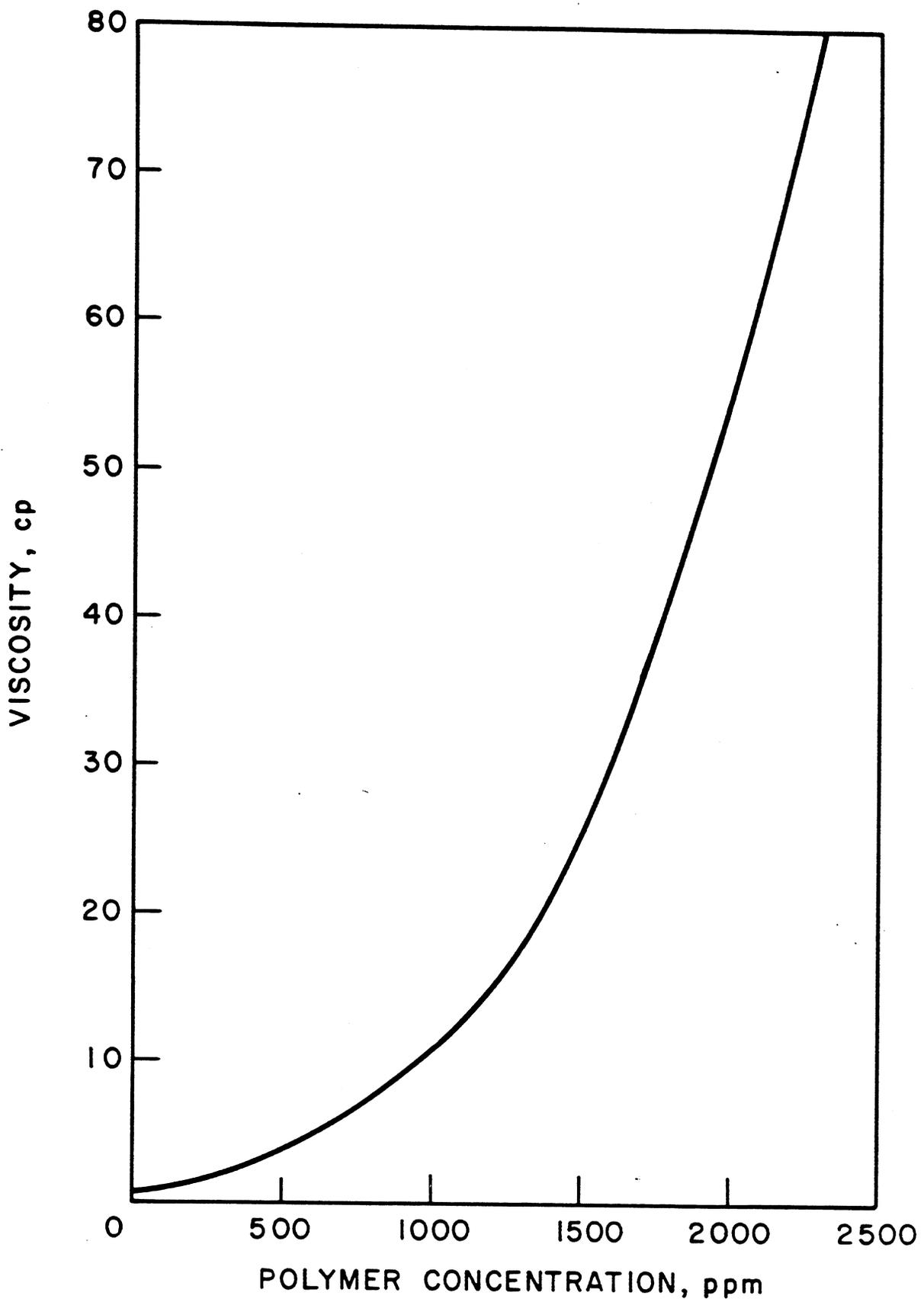


FIGURE 3. - Viscosity of Polymer Solution Versus Polymer Concentration.

had a dual role in the surfactant/polymer process. First, it served as a buffer to preserve the integrity of the surfactant slug by maintaining a favorable mobility ratio between the drive fluid and the surfactant. Second, it supplemented the surfactant action by improving the volumetric sweep, resulting in additional enhancement of oil displacement aside from surfactant action. The above information served as a basis for developing input data for simulation.

The reservoir layout and structure, as used in the project design and necessary in the present simulation study, was based on a suite of logs and associated structural map work-up. A series of compensated neutron formation density logs were run in the North Burbank project area just before project start-up. The key for the logs is given in figure 4 (A-A') and the actual well logs are presented in figure 5. It is clear from this constructed cross-section that the Burbank sand correlates from well to well with good porosity development.

A set of geological and engineering maps were available which thoroughly describe the reservoir in the area of Tract 97. This information was important in establishing reservoir properties used in the simulation. In particular, isopermeability, isoporosity, structure, net pay and current oil saturation contours provided a direct measure of reservoir heterogeneity and aided in the selection of a suitable area to focus the simulation effort.

The isopermeability map for the North Burbank project area is shown in figure 6, and from this it is clear that there is a gradation in permeability in Tract 97 from southwest to northeast with the better permeabilities located in the northeast quadrant of the tract. The area that formed the basis for the finite-difference simulation was selected from this quadrant.

An isoporosity map for the project (figure 7) generally does not correlate with the isopermeability map and does not exhibit any general trends. The average porosity over Tract 97 was 16.5 percent. The porosity used in the simulation was considered uniform and set equal to this value.

The structure map for the project is shown in figure 8. It is interesting to note that the better permeability development is generally up-structure and to the northeast where a crest occurs in the structure. Note also that there is no dip between the injection well W26 and the producer 6 which were the focal points for the simulation.

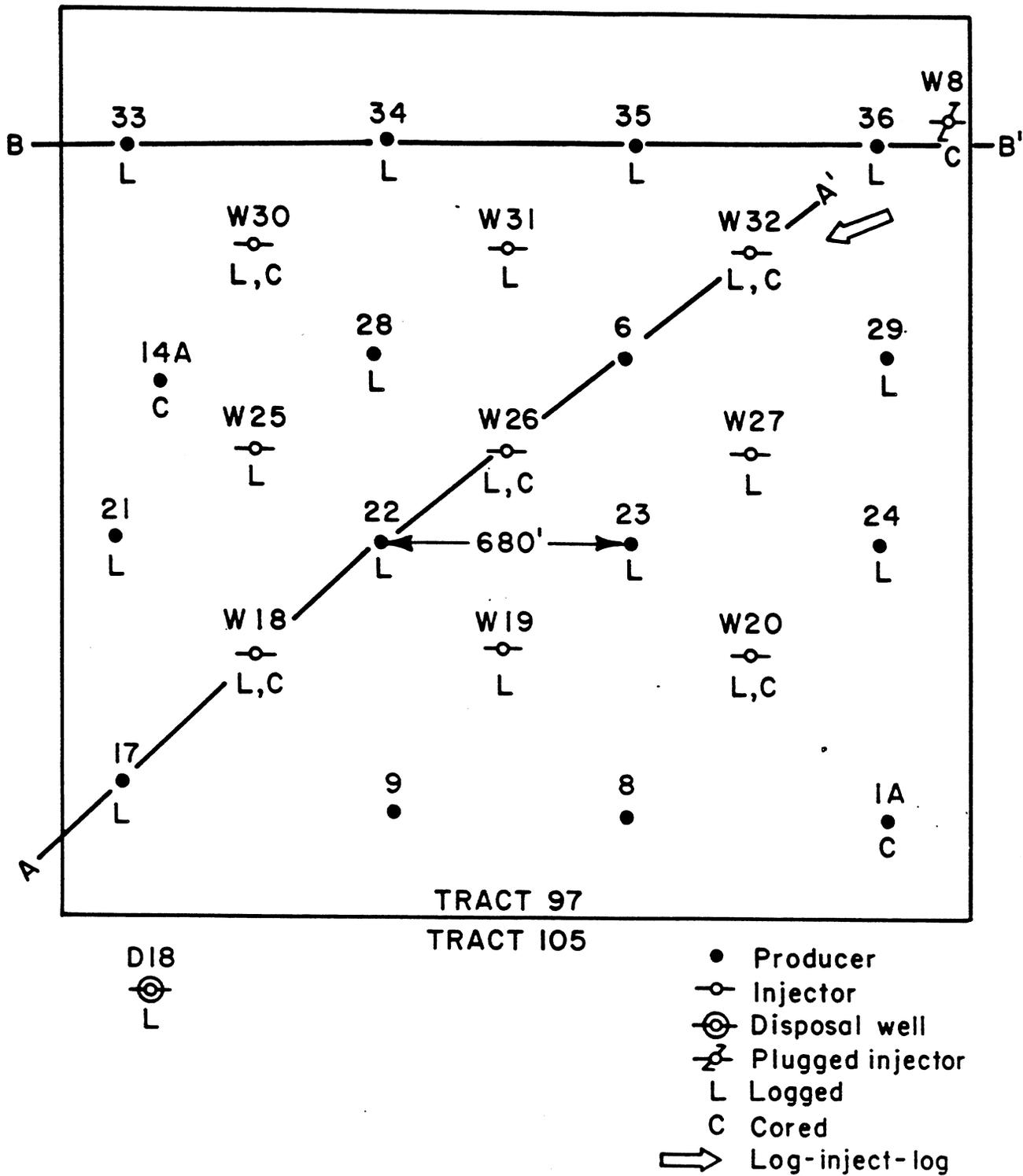


FIGURE 4. - Well Locations Showing Cored and Logged Wells.

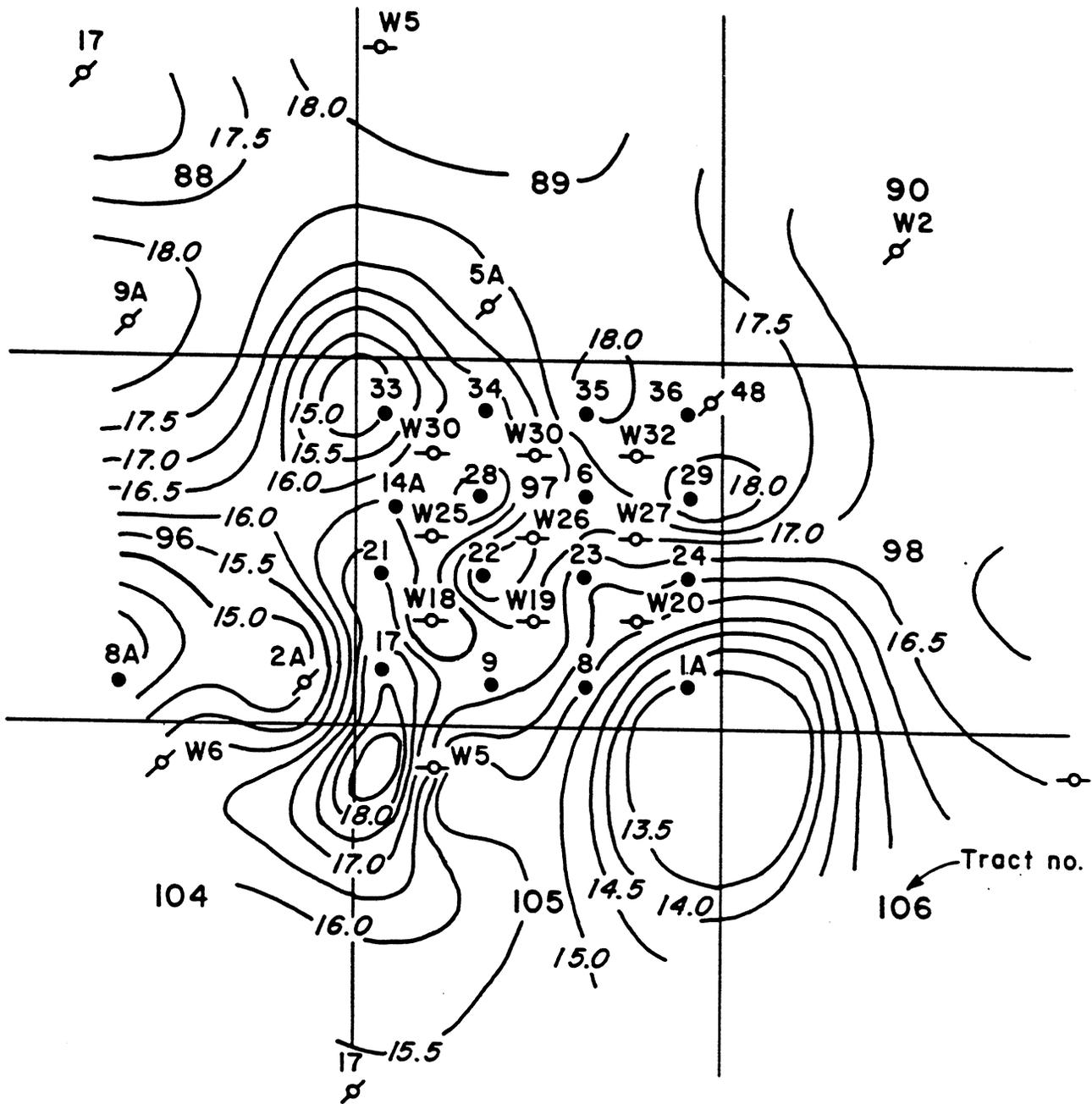


FIGURE 7. - Isoporosity Map. North Burbank Unit Tract 97 Area.

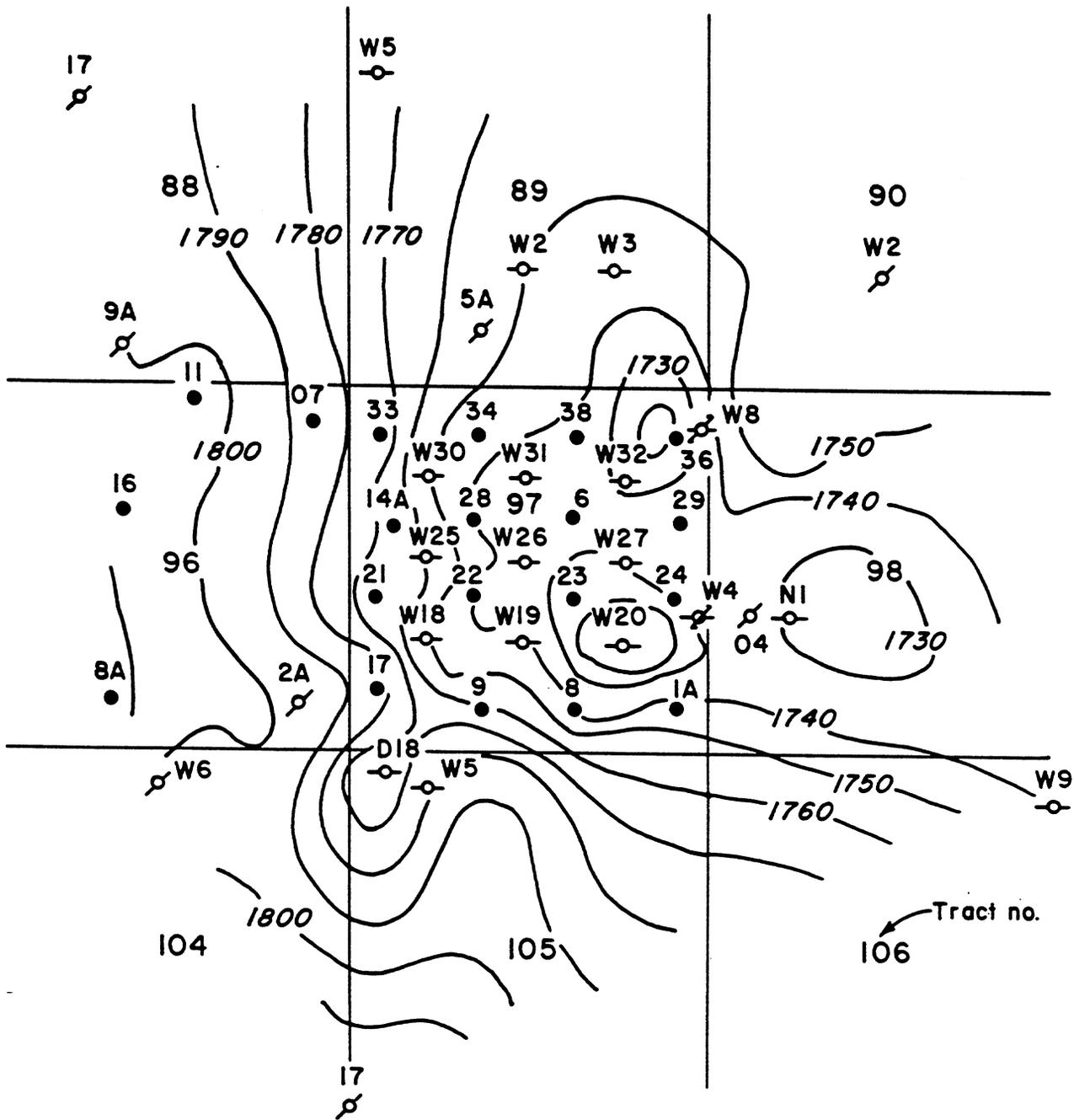


FIGURE 8. - Structure Map. North Burbank Unit Tract 97 Area. Contoured on Top of Burbank Sand.

A plot of the net oil sand for the project is shown in figure 9 and generally does not correlate with the structure map or the isopermeability map. The average net pay over the project area was 43 feet and this value was used in the simulation. The reservoir thickness (net pay) was considered uniform.

A plot of current oil saturation at the start of the chemical flood is shown in figure 10 for Tract 97. Variations in oil saturation are less than 10 percent over the project area. The maximum value of oil saturation (38%) occurs around wells W26 and W31. The oil saturation averages 35 percent between wells W26 and 6 which agrees with the overall project average. As a result, a uniform value of oil saturation of 35 percent was used in the simulation.

The four interior production wells (wells 6, 22, 23 and 28) are completely confined, i.e., they are completely surrounded by injection wells. Thus, these wells should have experienced the strongest influence from the injected chemicals. The resulting production profiles for these four interior wells are shown in figures 11, 12, 13 and 14. It is clear from these profiles that wells 22 and 23 did not respond significantly to the injected chemicals. On the other hand the response of well 28, while significant, was rather erratic with several well defined peaks. It is clear from the lack of a well defined and symmetrical response from each of the confined wells that a definitive "history match" of this pilot test will not be possible without a very detailed analysis of all logs, cores and pressure profiles of all wells in the area. This data would then have to be incorporated into a very high resolution chemical flood simulation. It was decided by the DOE Technical Officer that this level of detail was beyond the scope of this analysis. Instead, the simulation described below has been designed to uncover the salient features of the project and relate these features to the equivalent predictions of a simpler, predictive chemical flood process model.

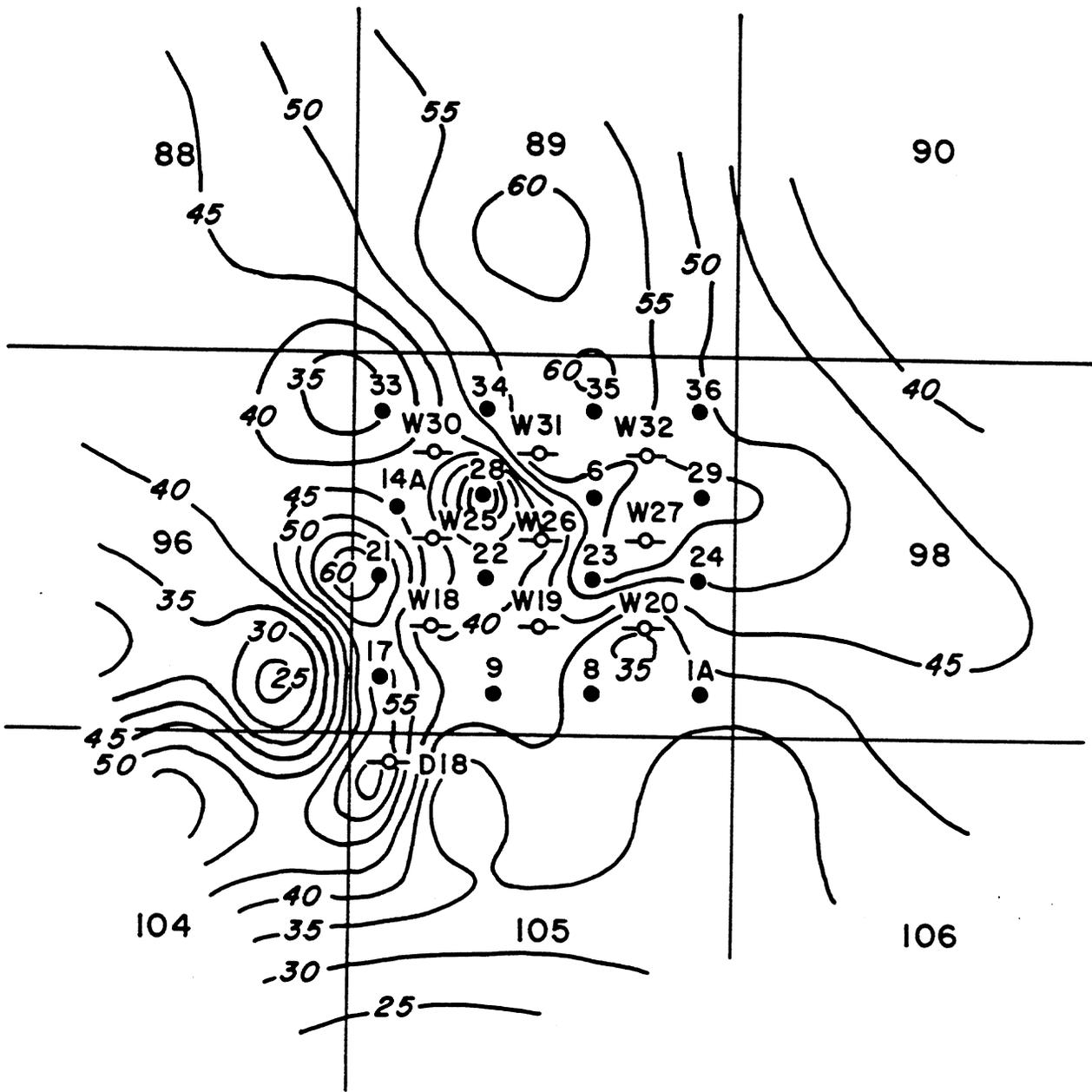
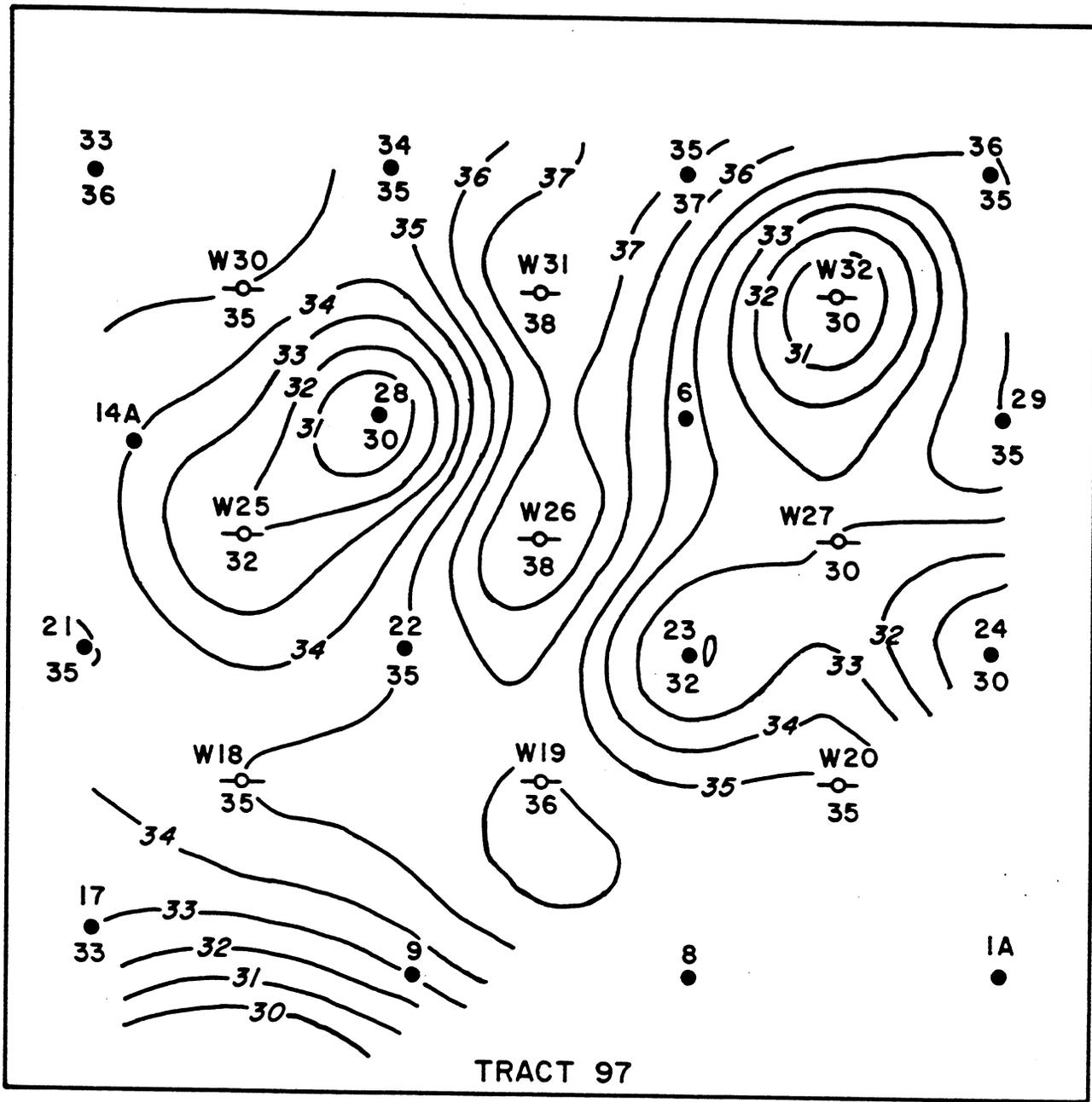


FIGURE 9. - Net Oil Sand. North Burbank Unit Tract 97 Area.



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FIGURE 10. - Current Oil Saturation at Start of Chemical Flood, Tract 97.

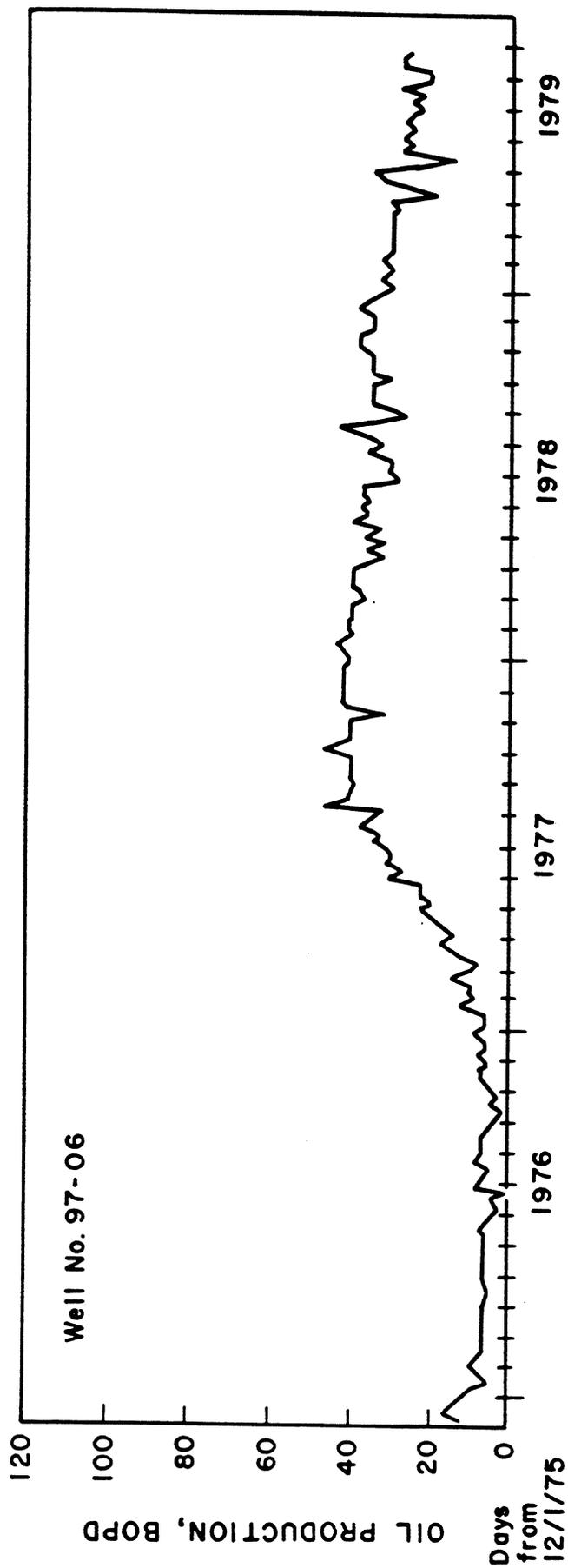


FIGURE 11. - Production Performance Well 97-06

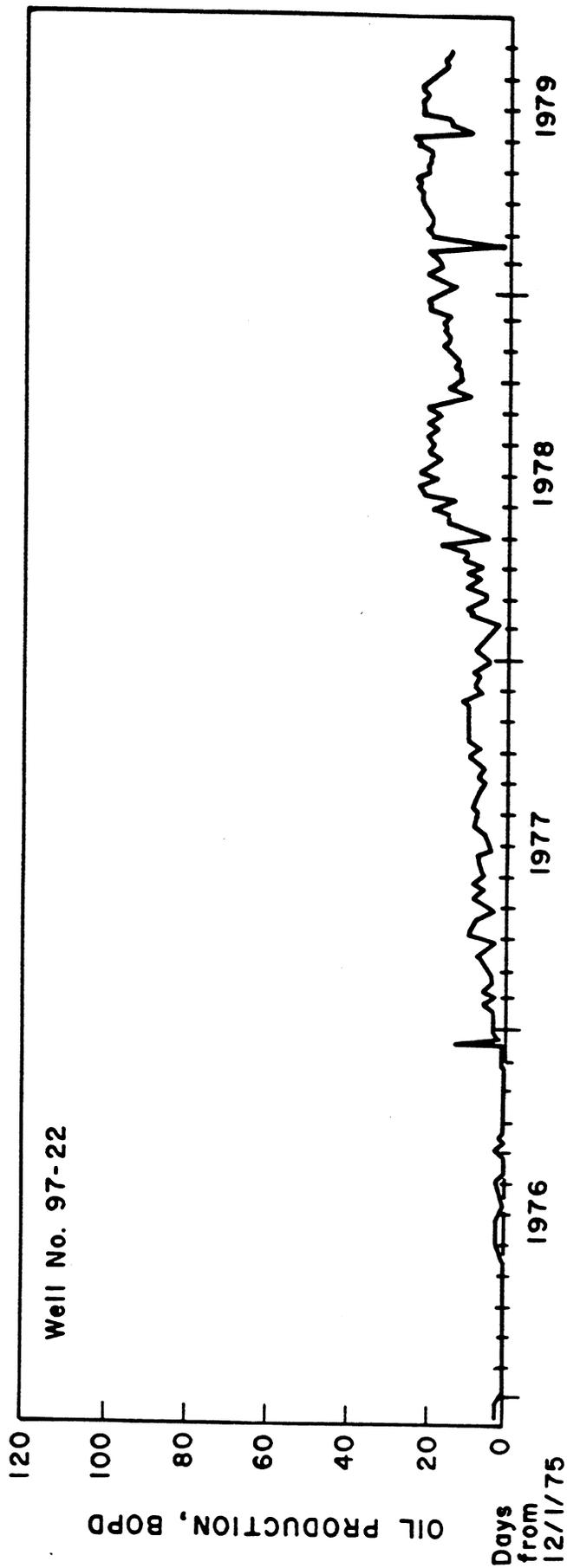


FIGURE 12. - Production Performance Well 97-22

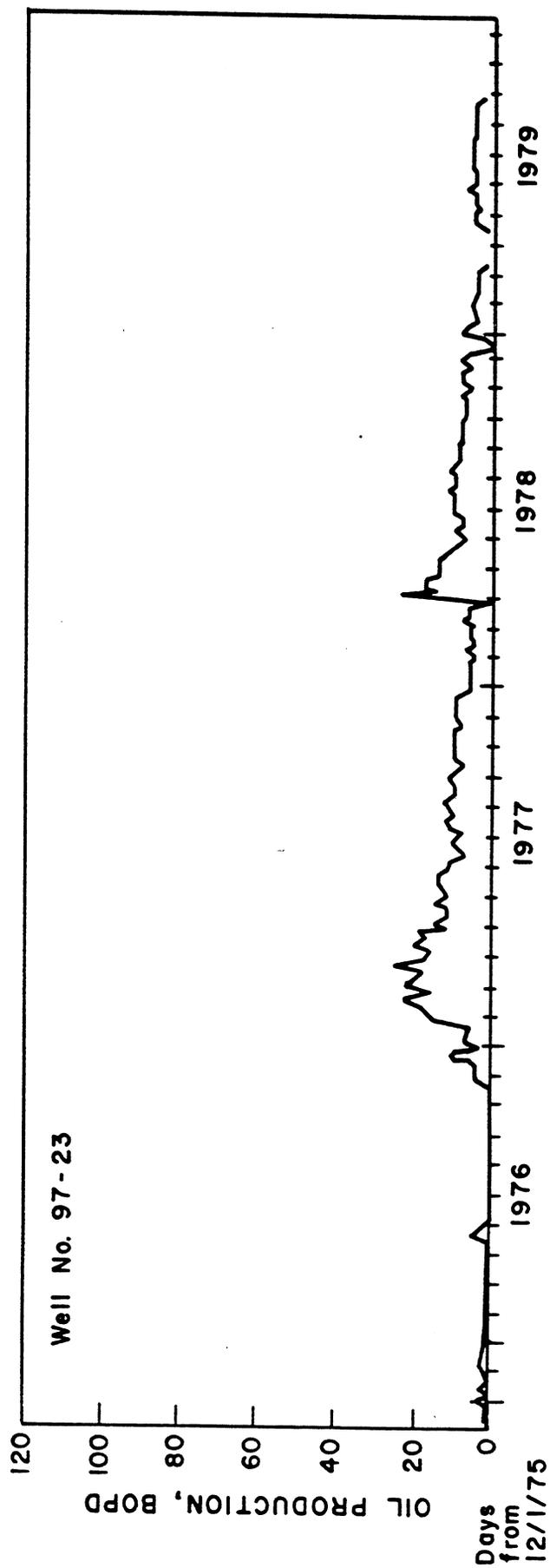


FIGURE 13. - Production Performance Well 97-23.

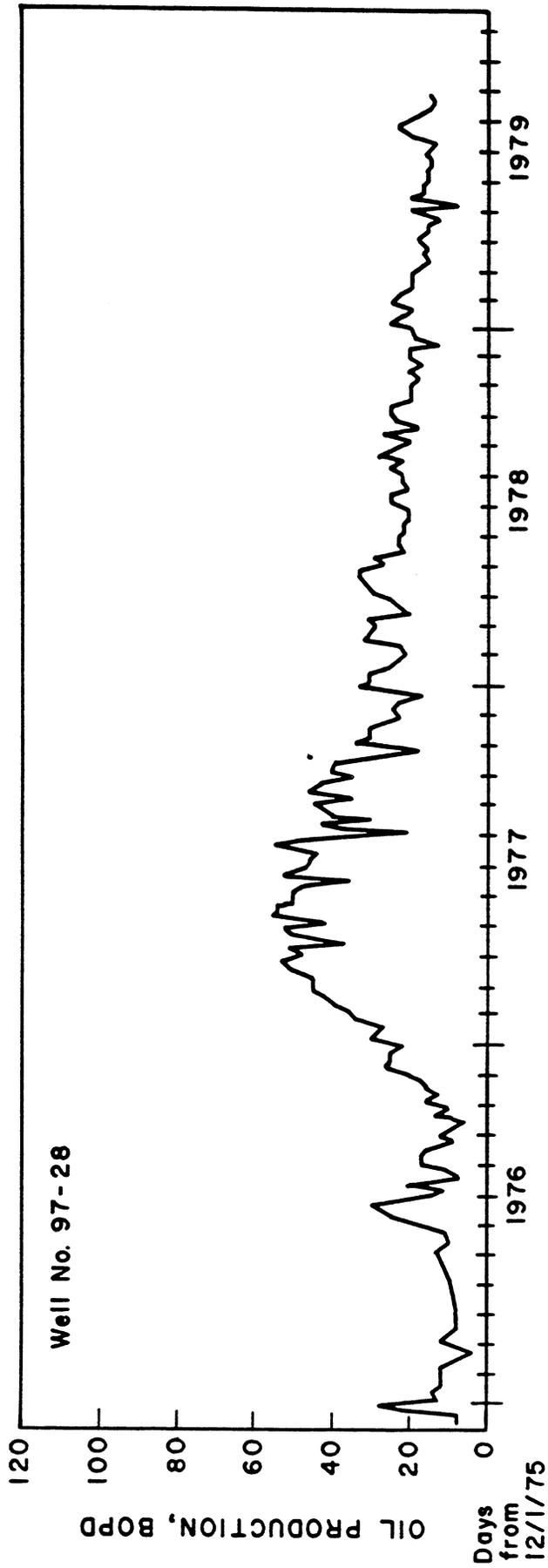


FIGURE 14. - Production Performance Well 97-28.

SIMULATION OF NORTH BURBANK CHEMICAL FLOOD PROJECT

The computer program used initially in the simulation of the North Burbank Chemical Flood Project was NICHEM3. This NIPER simulator is a state-of-the-art finite-difference three-dimensional, multi-phase, multi-component micellar/polymer flooding program based on a program developed originally at the University of Texas by Akhil Gupta (8). The simulator was substantially upgraded and modified for applications using the DOE Perkin-Elmer 3230 computer. The solution technique used in this simulator is analogous to IMPES (implicit pressure explicit saturation), but overall concentrations instead of saturations are determined initially. The simulator provides for surfactant and polymer adsorption and partitioning of the components between phases.

Phillips Petroleum Company performed a mathematical simulation on portions of the North Burbank Chemical Flood Project in 1979 (2). The cumulative oil production from each of the four confined producing wells in the pilot was successfully duplicated over a period of two and one-half years, starting from the time when preflush injection was initiated. The finite-difference model employed represented a two-dimensional vertical slab with six layers and, thus, provided for vertical heterogeneity. The partitioning of surfactant and alcohol into aqueous, microemulsion, and oil phases was taken into account along with retention of these components by the reservoir. Polymer retention and the mobility control provided by the graded polymer solution were also included. The permeability distributions used in the simulations were based on core analyses from wells in the pilot area but were modified to bring the simulated production into agreement with the observed production. An important result of this simulation was that the surfactant retention level necessary to duplicate production profiles (9,500 lb/acre-ft) was substantially greater than that measured in the laboratory (2,200 lb/acre-ft). This result was also obtained in the present work using NICHEM3, although extracted surfactant retention levels are not identical.

In the present work, a decision was made to base the simulation on one quarter of a five-spot including wells W26 (injector) and 6 (producer). This decision was predicated on the fact that the finite-difference simulator employed (NICHEM3) is currently limited to two wells. The two wells selected for the simulation are located in an area of the reservoir where there is virtually no dip and representative current oil saturation (35%). Efforts

were concentrated on simulating the performance of well 6 since this well possessed a well defined production profile.

A three-dimensional 11 X 11 X 2 grid was utilized in the simulation since this grid invoked the full grid block range of NICHEM3 as it was currently dimensioned. This grid is shown schematically in figure 15. The specification of two layers was based on evidence from core analysis of a well in the project area (figure 16). Consistent with this core analysis, the upper layer permeability was set at 200 md, and the lower layer permeability was set at 50 md. Cross flow between layers was accounted for by setting the vertical permeability equal to 20 md.

The reservoir properties assumed in the simulation are given in table 2. The surfactant adsorption assumed in the simulation (4342 lb/acre-ft) is approximately twice that measured in laboratory core flood experiments (2,200 lb/acre-ft) and is less than half that estimated by Phillips in their original simulation (9,500 lb/acre-ft). The polymer viscosity used in the simulation was in the form of a cubic equation and was fit to the viscosity versus concentration relationship as reported by Phillips (figure 3).

The components assumed in the simulation are given in table 3. These components could partition between any of the three phases: water, oil, and microemulsion.

The injection stages used in the simulation are given in table 4. The injection rates for each stage were determined by first taking the total fluid injected for that stage and then dividing by the duration. This rate was then divided by four to yield the rate for a quarter of a five-spot which was then consistent with the grid used in the simulation. Note that the graded polymer drive was strictly adhered to in the simulation.

In the initial simulations, a value of 0.5 days was used for the time step. This value of time step yielded consistently smooth oil and water production rates with no sign of instability. However, execution times were quite long using these time steps with total execution times exceeding one week on the DOE Perkin-Elmer 7/32 computer. When the time steps were increased to five days the total execution time decreased by a factor of ten.

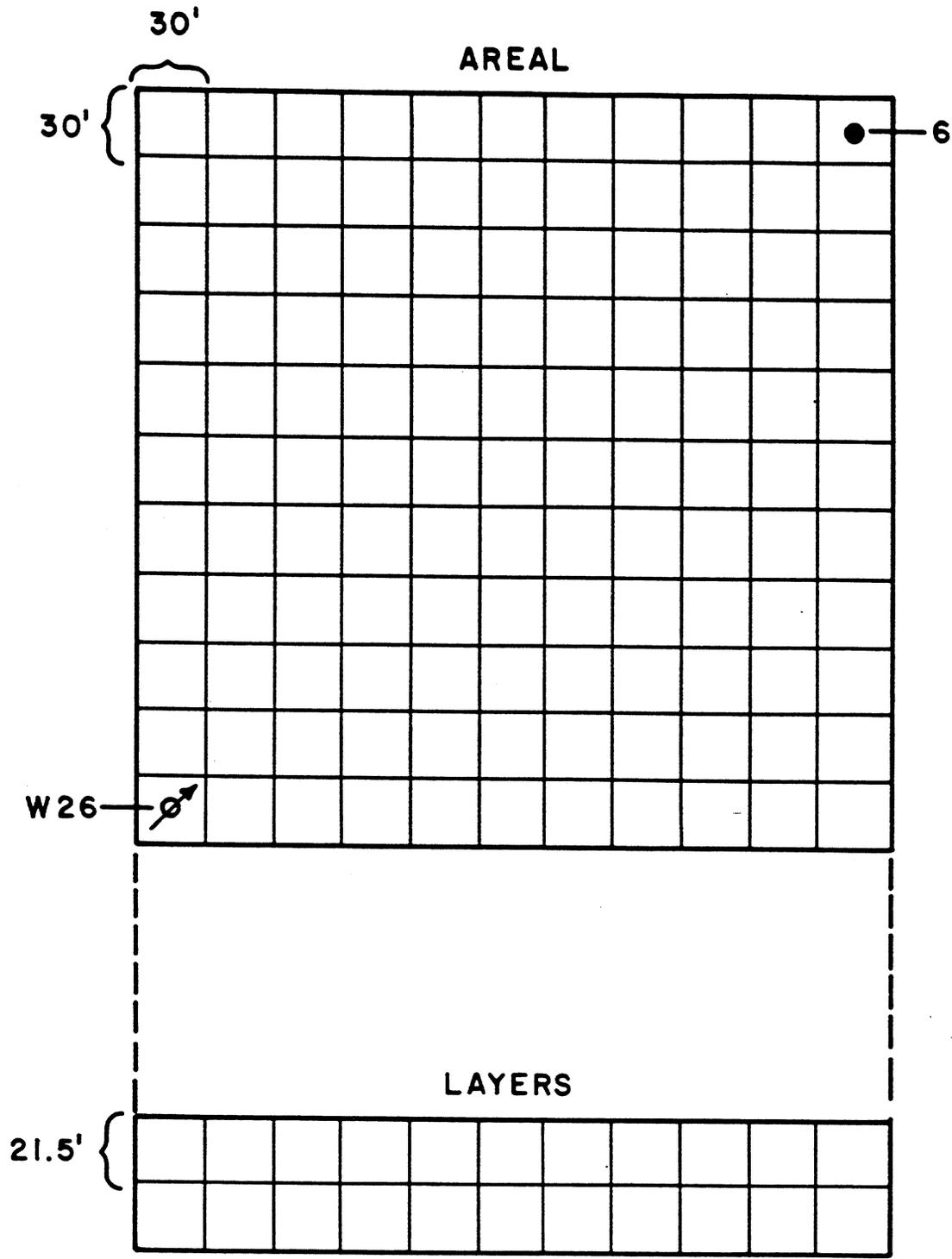


FIGURE 15.
Simulation Grid

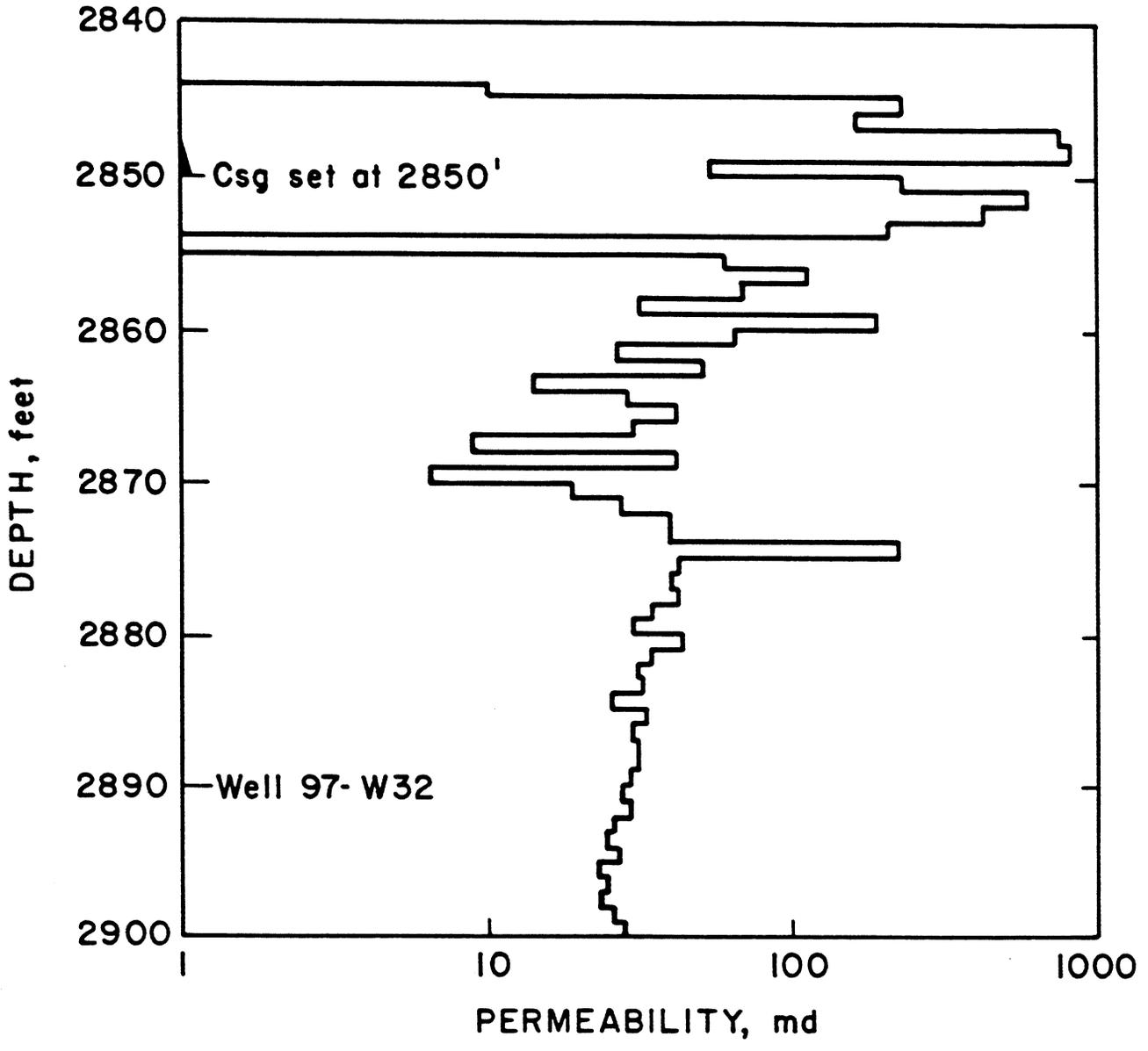


FIGURE 16. - Core Profile, Tract 97.

TABLE 2

Reservoir Properties Assumed In Simulation

Permeability - Upper Layer	200 md
Permeability - Lower Layer	50 md
Vertical Permeability	20 md
Porosity	0.165
Reservoir Thickness	43.0 ft
Reservoir Pressure	950 psia
Initial Oil Saturation	0.35
Initial Water Saturation	0.65
Initial Gas Saturation	0.0
Residual Oil Saturation	0.325
Connate Water Saturation	0.355
End Point Water Relative Permeability	0.11
End Point Oil Relative Permeability	0.95
Oil Relative Permeability Exponent	2.16
Water Relative Permeability Exponent	1.0
Initial Reservoir Na ⁺ Concentration (meq/ml)	0.689
Initial Reservoir Ca ⁺⁺ Concentration (meq/ml)	0.15
Water Viscosity	0.6 cp
Oil Viscosity	3.0 cp
Surfactant Adsorption (lb/acre-ft)	4342

TABLE 3

Components Assumed In Simulation

Water

Oil

Surfactant

Polymer

Na⁺

Ca⁺⁺

Alcohol

TABLE 4

Injection Stages Used In Simulation

<u>Injection Stage</u>	<u>Injection Rate</u> (BBL/DAY)	<u>Duration</u> (DAYS)	<u>Composition</u>
Fresh Water Preflush	220.0	140	Fresh Water
Saline Preflush	192.0	105	Water, Na ⁺ (0.662 meq/ml)
Surfactant	124.5	44	Water (91%), Surfactant (6%), Na ⁺ (0.662 meq/ml), Alcohol (3%)
Polymer (2500 PPM)	104.0	29	Water, Polymer (2500 PPM)
Polymer (2000 PPM)	104.0	42	Water, Polymer (2000 PPM)
Polymer (1500 PPM)	98.0	53	Water, Polymer (1500 PPM)
Polymer (1100 PPM)	141.0	50	Water, Polymer (1100 PPM)
Polymer (800 PPM)	115.0	54	Water, Polymer (800 PPM)
Polymer (600 PPM)	135.0	68	Water, Polymer (600 PPM)
Polymer (460 PPM)	136.0	66	Water, Polymer (460 PPM)
Polymer (250 PPM)	144.0	49	Water, Polymer (250 PPM)
Polymer (100 PPM)	148.0	77	Water, Polymer (100 PPM)
Drive Water	191.0	683	Fresh Water

However, the resulting output from such runs revealed gross instabilities in the oil production rates. Thus, a value of 1.0 day was used for the time step throughout this study. This was then a compromise between total execution time and oil rate stability. Using this value of time step, no instabilities in oil rate were ever observed, and a typical run took less than one day to execute on the new DOE 3230 Perkin-Elmer computer.

The relative permeabilities used in the simulation were approximately the same as those given by Phillips (figure 17). However, the residual oil saturation was adjusted to establish a good match to the initial oil production rates. A value of 0.325 was thus obtained for the residual oil saturation. The relative permeabilities were input to the simulator in standard exponential form. As a sensitivity test the exponents were decreased to one-half of their initial values. The resulting simulation yielded high oil production rates early in the life of the project. This result was not observed in the field so the exponents were set back to their original values. No further adjustment of relative permeability exponents was required in the simulation study.

The initial polymer viscosity used in the simulations was approximately five times too high. For example, the aqueous phase viscosity for a polymer concentration of 2,000 ppm was initially 257.1 cp. This resulted from the use of polymer viscosity data which was provided with the simulator. The viscosity should have been 53.5 cp. This correction was made, and the polymer viscosity data supplied by Phillips (figure 3) was closely followed. A comparison of the resulting simulations showed that the breakthrough of the oil bank was delayed by 60 days and the overall oil production rates were lower with the reduced polymer viscosity. This effect clearly shows that the simulation was sensitive to mobility control.

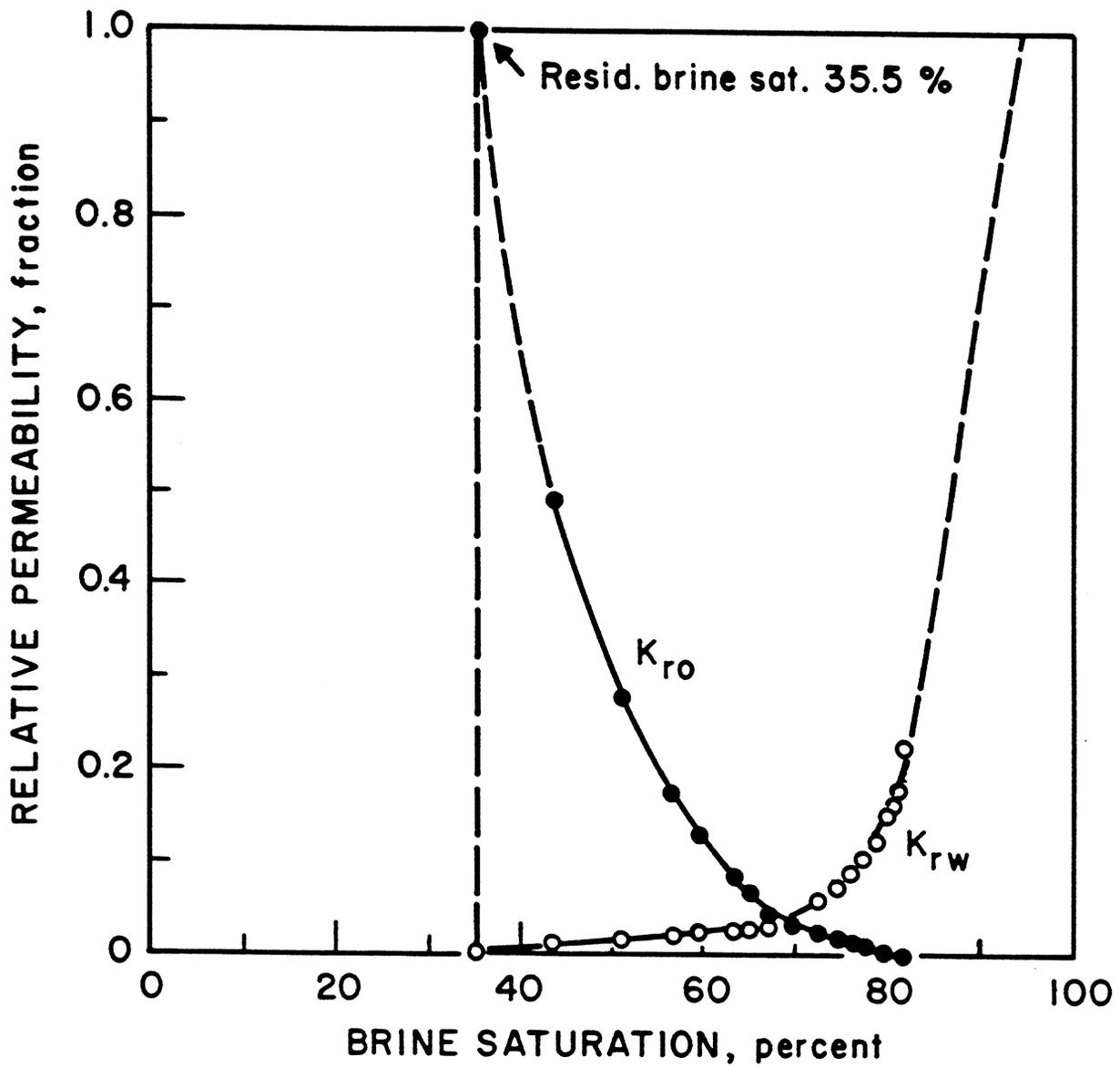


FIGURE 17. - Typical Relative Permeability Curves North Burbank Unit Tract 97.

The polymer adsorption is described by a Langmuir isotherm in the simulation. At a polymer concentration of 2,500 ppm the polymer adsorption was initially 19.5 lb/acre-ft. However, Phillips used a value of 70 lb/acre-ft for the polymer adsorption in their simulation study. The simulation results in the present study were found to be insensitive to polymer adsorption over this range of values.

The surfactant adsorption is also described by a Langmuir isotherm in the simulation. Figure 18 shows the simulation results for a run executed early in the study with the surfactant adsorption set at 2,200 lb/acre-ft (corresponding to a surfactant concentration of 0.06). Although the breakthrough of the oil bank is approximately correct, the oil production rates are much too high. This is the response expected using values of surfactant adsorption corresponding to laboratory measured estimates. The simulation was very sensitive to surfactant adsorption, and a value of 4,342 lb/acre-ft was extracted and used in the final simulation.

The final simulation results are plotted in figure 19. There is good agreement between the simulated and actual breakthrough time of the oil bank for well 6. There is also good agreement in the peak oil production rate. However, the oil production rates fall off rather rapidly in the simulation compared to the field results. With a six-layer model comparable to that which Phillips used, good agreement with the post-breakthrough oil rates could possibly have been achieved. However, this was considered artificial and not germane to the present study. The relatively high post-breakthrough production rates could have been due to channeling through fractures or other reservoir heterogeneities that could not be easily taken into account.

The results obtained above have been compared with a prediction of the North Burbank Project using DOE's Chemical Flood Predictive Model (CFPM). This comparison is outlined below.

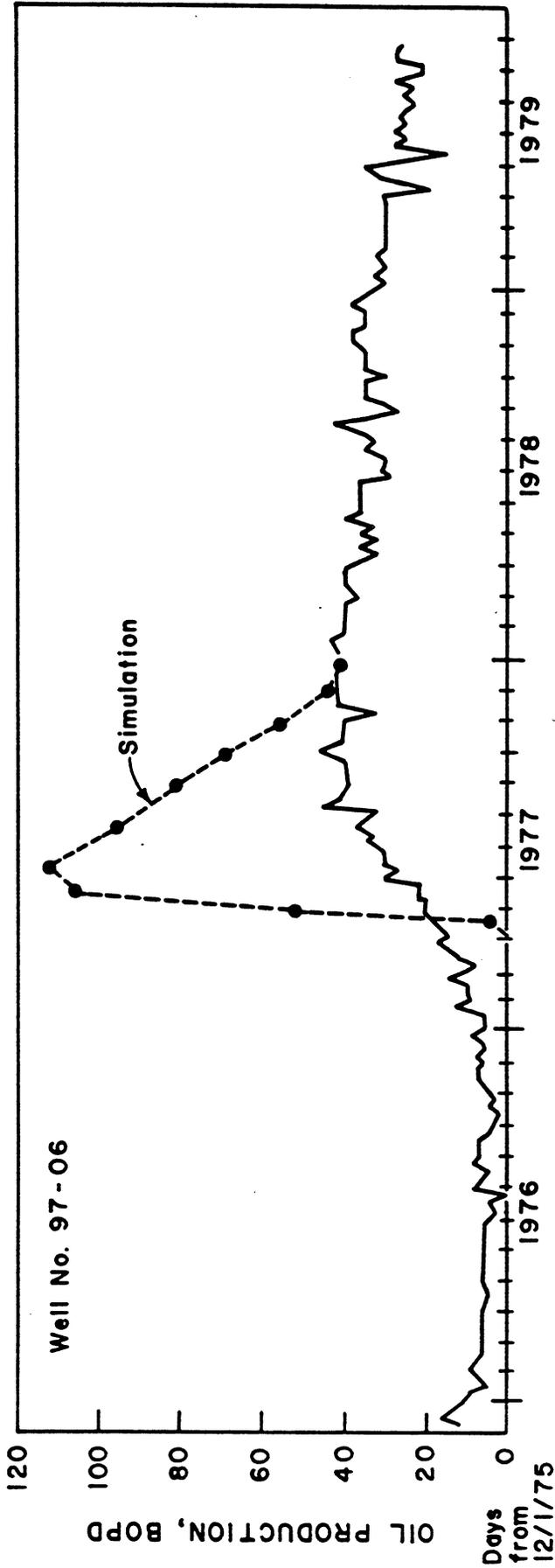


FIGURE 18. - Early Simulation - Surfactant Adsorption Set at Laboratory Measured Value (2,200 lb/acre-ft).

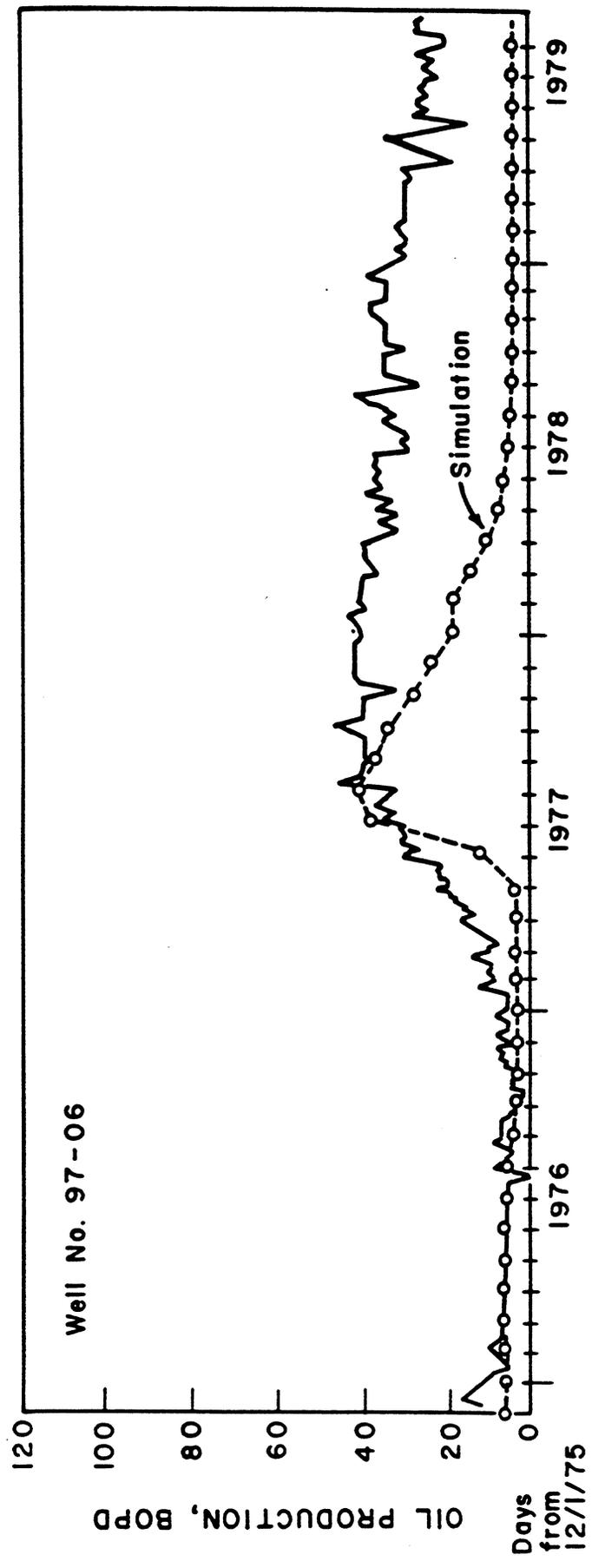


FIGURE 19. - Final Simulation.

In CFPM the surfactant retention is expressed in units of pore volumes of injected surfactant slug required to satisfy all adsorption. This quantity, denoted by D_s , was obtained in the following manner:

$$D_s = \frac{1-\phi}{\phi} \frac{\rho_r a_s}{\rho_s C_s} \frac{1}{1000}$$

where in the present case:

$$\phi = \text{porosity} = 0.165$$

$$\rho_r = \text{rock density} = 2.65 \text{ gm/cm}^3$$

$$\rho_s = \text{surfactant density} = 1.0 \text{ gm/cm}^3$$

$$C_s = \text{volume fraction of surfactant in injected slug} = 0.06$$

$$a_s = \text{surfactant retention in mg surfactant/g rock} = 0.72 \text{ (4342 lb/acre-ft)}$$

This gives a value of D_s of 0.16 for the North Burbank Project. This value of D_s was input to CFPM together with other data derived from the finite-difference simulation. The tabulated data input for the CFPM is given in table 5. A pattern production report from CFPM is given in table 6, and the resulting predictive model output together with output from NICHEM3 are shown in figure 20. The CFPM result roughly parallels the result using the finite-difference simulator, however, the oil production rates are too high. From experience gained in the use of the finite-difference simulator, this result implies that CFPM does not adequately take into account the effect of surfactant adsorption. This follows since both CFPM and finite-difference simulator runs were based on a surfactant adsorption of 4342

TABLE 5

CFPM Data Input

<u>Case Controls</u>		
Economic analysis control	0	IECON
Caustic option (on IF GT 1)	0	ICAUST
<u>Formation Properties</u>		
Formation depth	2900.0	Feet
Formation temperature	120.0	DEG.F
Max screen temperature	230.0	DEG.F
Formation salinity	18600.0	PPM TDS
Max screen salinity	80000.0	PPM TDS
Original oil in place	0.300	MMSTB
Cumulative oil produced	0.110	MMSTB
Formation Porosity	0.1650	FRACTION
Formation permeability	125.0	MD
Formation net pay	43.0	FEET
Pseudo net pay	43.0	FEET
Dykstra-Parsons coefficient	0.6000	VDP
Surfactant sorption, VOL/Pore vol	0.1600	DSIN
WT fraction clay	0.120	FRACTION
Formation KV/KH ratio	0.10000	KV/KH
Cross flow mixing factor	3.432	RL
<u>Initial Conditions</u>		
Fraction bottom water	0.0000	FRACTION
Fraction gas cap	0.0000	FRACTION
Oil density	39.0	DEG API
Solution gas-oil ratio	50.0	SCF/STB
Initial oil formation factor	1.200	RB/STB
Flood oil formation factor	1.050	RB/STB
Flood water formation factor	1.029	RB/STB
Oil viscosity at reservoir cond	3.000	OP
Wtr viscosity at reservoir cond	0.600	OP
Rock density at flood cond	2.650	G/ML
Surf density at flood cond	1.000	G/ML
Surf concentration in slug	0.0600	VOL FR
Dimensionless slug size	0.250	VPS/DS
Large VPS/DS core flood recovery	0.0000	EDIN

TABLE 5 (Continued)

CFPM Data Input

Relative Perm Curves

Irreducible water saturation	0.355	SWC
Residual oil saturation after water	0.325	SORW
Oil relative permeability end-point	0.950	KORO
Water relative permeability end-point	0.110	KORW
Oil relative permeability curvature	2.16	XNO
Water relative permeability curvature	1.00	XNW

Recovery Efficiency Summary

Field capillary number	1.45E-03	
Displacement efficiency	0.7406	ED
Cross flow mixing factor	3.432	RL
Dimensionless surfactant retention	0.1600	DS
Dimensionless slug size	0.6067	VPS/DS
Fractional slug size	0.0700	VPS
Pore volume mobility buffer	1.270	VPMB
Heterogeneity factor	0.600	VDP
Effective mobility ratio	5.256	EFF
Flow capacity of layer M	0.158	FM
Storage capacity of layer M	0.034	CM
Vertical sweep efficiency	0.5454	EV
Areal sweep efficiency	1.0000	EA
Mobility buffer efficiency	0.6000	EMB
Cross flow performance factor	1.3000	FCF
Tertiary oil recovery efficiency	0.3151	ER

Injection/Production Summary

Pattern surfactant slug volume	38.5	M.BBL
Initial polymer concentration	894.6	PPM
Pattern polymer requirement	96.0	M.LB
Dimensionless surfactant velocity	0.465	VELS
Dimensionless oil bank velocity	1.157	VOB
Oil breakthrough pore volume	0.164	TDOB
Peak rate pore volume	0.409	TDS
Sweep out pore volume	1.558	TDSW
Oil breakthrough time	0.420	YEARS
Peak rate time	1.046	YEARS
Total pattern life	3.983	YEARS
Fractional flow of oil at peak	0.147	FOPK
Injectivity coefficient	0.300	PSI/FT
Steady state pattern rate	590.00	RB/D
Oil rate at peak	82.57	STB/D
Water saturation in bank	0.5315	SWB
Water fractional flow in bank	0.6428	FWB
Pattern spacing	10.00	ACRES

TABLE 5 (Continued)

CFPM Data Input

Injection/Production Summary (Continued)

Total developed area	9.11	ACRES
Number of effective patterns	0.91	
Pattern floodable pore volume	0.5504	MMRB
Pattern target oil	0.1704	MMSTB
Starting oil saturation	0.3250	SOR
Project floodable pore volume	0.502	MMRB
Project target oil	0.155	MMSTB
Total oil recovery	0.049	MMSTB

TABLE 6

CFPM Data Output

TIME YEARS	OIL RATE B/D	GAS RATE MSCF/D	WATER RATE B/D	CUM OIL MBBL	CUM GAS MMSCF	CUM WATER MBBL
0.25	0.0	0.0	573.4	0.0	0.0	0.0
0.50	10.5	0.5	562.7	0.0	0.0	52.3
0.75	43.5	2.2	529.0	1.0	0.0	103.7
1.00	76.5	3.8	495.3	4.9	0.2	151.9
1.25	76.8	3.8	495.0	11.9	0.6	197.1
1.50	69.8	3.5	502.1	18.9	0.9	242.3
1.75	62.8	3.1	509.3	25.3	1.3	288.1
2.00	55.8	2.8	516.5	31.0	1.6	334.6
2.25	48.7	2.4	523.7	36.1	1.8	381.7
2.50	41.7	2.1	530.8	40.6	2.0	429.5
2.75	34.7	1.7	538.0	44.4	2.2	477.9
3.00	27.6	1.4	545.2	47.5	2.4	527.0
3.25	20.6	1.0	552.4	50.0	2.5	576.8
3.50	13.6	0.7	559.5	51.9	2.6	627.2
3.75	6.5	0.3	566.7	53.2	2.7	678.2
3.98	0.0	0.0	590.0	53.8	2.7	730.0

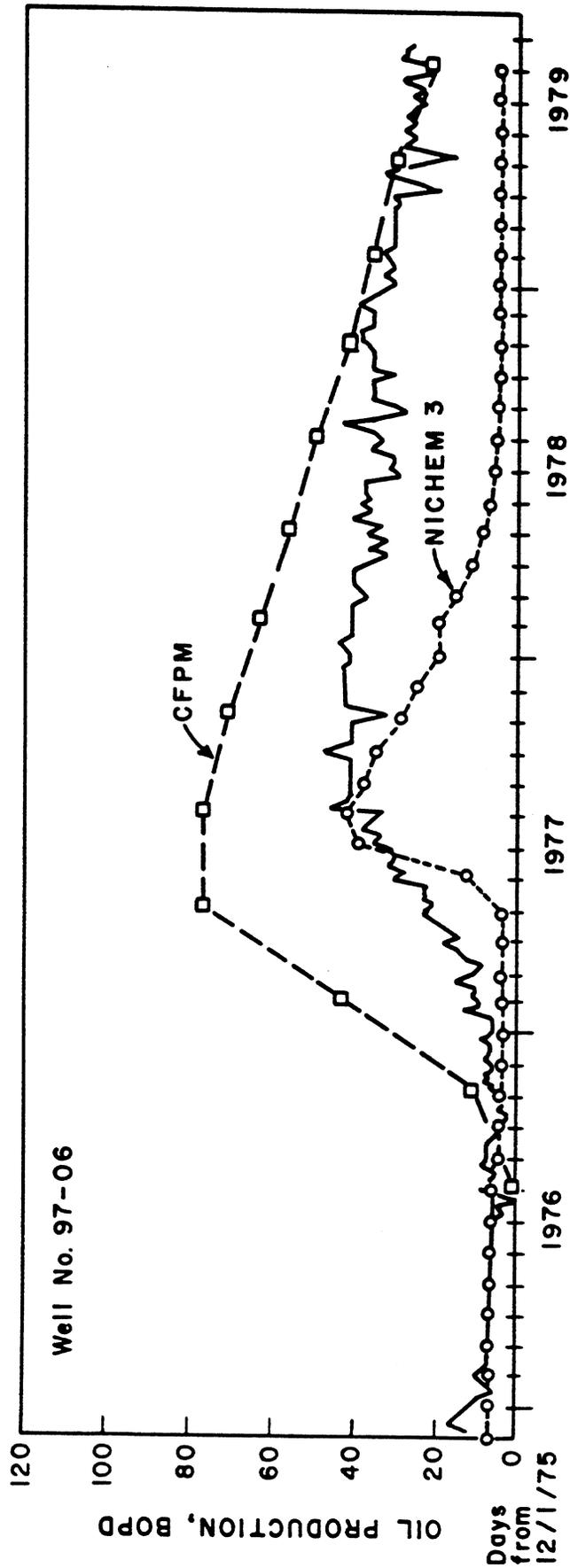


FIGURE 20. - Comparison of CFPM and NICHEM3.

1b/acre-ft. Production rates from CFPM can be adjusted to be in conformance with the detailed simulation by arbitrarily adjusting D_s or its correlational form. However, given the ad-hoc nature of such a method, this would not provide a modification that could be used generally for other chemical flood projects. If peak production rates were available from project data prior to CFPM prediction, then these could be used to calibrate D_s to the project. Simulations with CFPM could then be considered to parallel the results obtained from a definitive finite-difference simulation for that project.

CONCLUSIONS AND RECOMMENDATIONS

A simulation study of the North Burbank Chemical Flood Project has been completed using a finite-difference simulator (NICHEM3) and a Chemical Flood Predictive Model (CFPM). In the final finite-difference simulation there was good agreement between the simulated and actual breakthrough time of the oil bank for well 6 of Tract 97. There was also good agreement in the peak oil production rate. However, the oil production rates fell off more rapidly in the simulation compared to the field results. With a multi-layer model better agreement with the post-breakthrough production rates could possibly have been achieved. However, this was considered artificial and not attempted in the present work, since high post-breakthrough production rates were possibly due to unknown reservoir heterogeneities such as fractures that could not be easily incorporated into the simulation. Emphasis was placed instead on making comparisons with CFPM. The CFPM result paralleled the result using NICHEM3, however, the oil production rates were too high. This effect was attributed to an inadequate treatment of surfactant retention in CFPM. If project peak production rate is available, or can be estimated, then the surfactant loss can be calibrated. CFPM can then be used as an adequate screening level predictor of project performance.

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ACKNOWLEDGMENT

Figures for this report were taken from annual reports on the project and quarterly Progress Reviews of contracts for enhanced oil recovery research, both published by the Department of Energy.

