Case History of Waterflooding the Yates Sand Ward County, Texas

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The 600 acre Forest A. B. Gordon lease has produced 5,500,000 bbl (9,167 B/A) of waterflood oil to March 1, 1966. This oil has been produced from the Yates formation and principally from the Penn Bennett member. The primary recovery from this lease was 2,474,000 bbl or 4,123 B/A, or a waterflood to primary ratio of 2.2 to 1.

The A. B. Gordon (Fig. 1) waterflood is but one of many successful floods in the South Ward Field of southeastern Ward County, Texas, several of which have been reported on previously.

It is the intent of this paper to review some of the information available at the start of waterflooding to see how reliable the various types of initial information would be in predicting waterflood response.

Before going into these comparisons we will briefly look at the general character of the reservoir involved.

The upper member of the Permian Yates formation is the Grand Falls member (Fig. 2). In this area gas was present in this pay down to approximately 260 ft above sea level. Numerous gas blowouts were encountered on initial drilling and on subsequent completion gas was produced at high rates along with the oil. Although the sand development of this member was widespread it was not an important pay in the field. This was particularly so on the A. B. Gordon Lease where it is estimated to account for only 10 per cent of the oil produced.

The lower member of the Yates, the Penn Bennett, appears to be much the same as the Grand Falls in that the pay zones are separated by dolomite or dolomitic sand; but generally in the Penn Bennett member continuity of the pay zones is better, there is no gas cap problem, the permeability is more uniform and the oil viscosity lower.

Because the Grand Falls production was of such a minor nature on this lease the remaining data will pertain to the Penn Bennett.

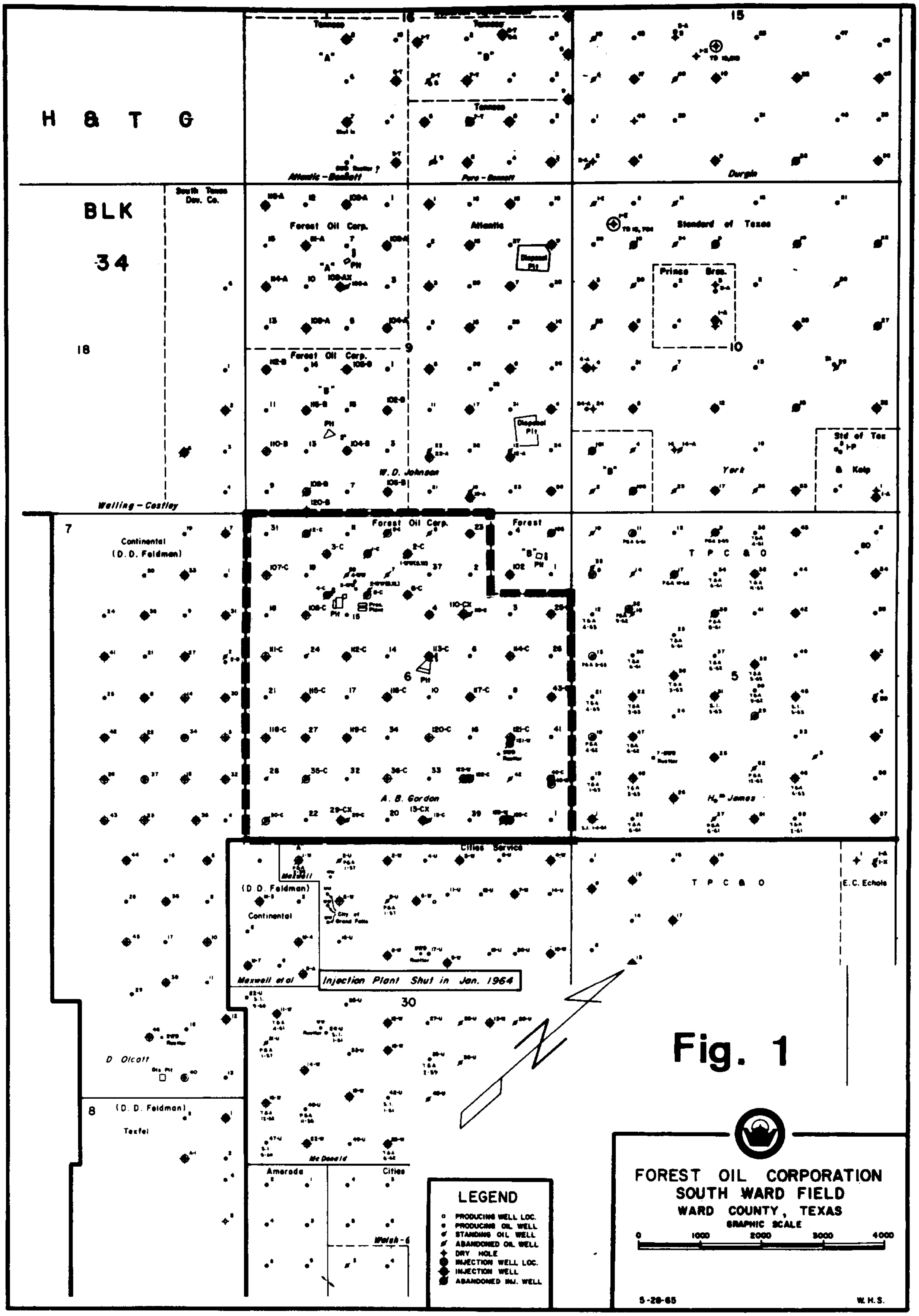
Table I shows the pertinent physical properties of the Penn Bennett Sand and the contained crude oil.

It is noteworthy that 25 cores were taken during the waterflood development of this 600 acre lease. Most of these cores were chip cores; that is, cable tool cuttings chipped with a modified bit and using short runs to produce fragments up to an inch in length and from ¼ to ½-in. thick. These samples required a modified core analysis technique but had the considerable advantage of providing more reliable fluid analysis than the conventional rotary cores. On the average, chip core saturation indicated a 15 per cent higher oil saturation and a 7 per cent lower water saturation than the rotary cores. The 26 per cent water saturation used in Table I was the actual water content shown by two chip cores that were making fair quantities of oil at the time of chipping.

TABLE I
RESERVOIR FACTORS
A. B. GORDON LEASE

Acres	600
Net Pay (Feet)	23.5
Porosity (%)	20.4
Permeability Mds.	82
Core Oil Saturation %	32.9
Core Water Saturation %	41.5
Estimated Water Saturation %	26.0
Formation Vol. Factor	1.215
Residual Oil Saturation Flood Pot Tests %	15.3
Estimated Field Residual Oil Saturation After Waterflood %	20.0
Oil Viscosity at Reservoir Temperature (75°F.) cps.	3.1

Reservoir Volume:
Porosity 20.4 x 77.58 = 1583 BAF
1583 x 23.5 (pay thick.) = 37,200 BA
37,200 x 600 (acres) = 22,320,000 bbls
or A. B. Gordon Lease contains 22,320,000 bbls. void spc.


H & T G
BLK
34
Forest Oil Corp.
Atlantic
Standard of Texas
Prince Bros.
W. D. Johnson
Welling - Castley
Continental
(D. D. Feldman)
Forest Oil Corp.
Forest
T P C & O
A. B. Gordon
H. M. James
Cities Service
Continental
Maxwell et al
Injection Plant Shut in Jan. 1964
D Olcott
Texfel
McDonald
Amerada
Cities
E. C. Echols
LEGEND
PRODUCING WELL LOC.
PRODUCING OIL WELL
STANDING OIL WELL
ABANDONED OIL WELL
DRY HOLE
INJECTION WELL LOC.
INJECTION WELL
ABANDONED INJ. WELL
FOREST OIL CORPORATION
SOUTH WARD FIELD
WARD COUNTY, TEXAS
GRAPHIC SCALE
0
1000
2000
3000
4000
5-28-65
W.H.S.
Fig. 1

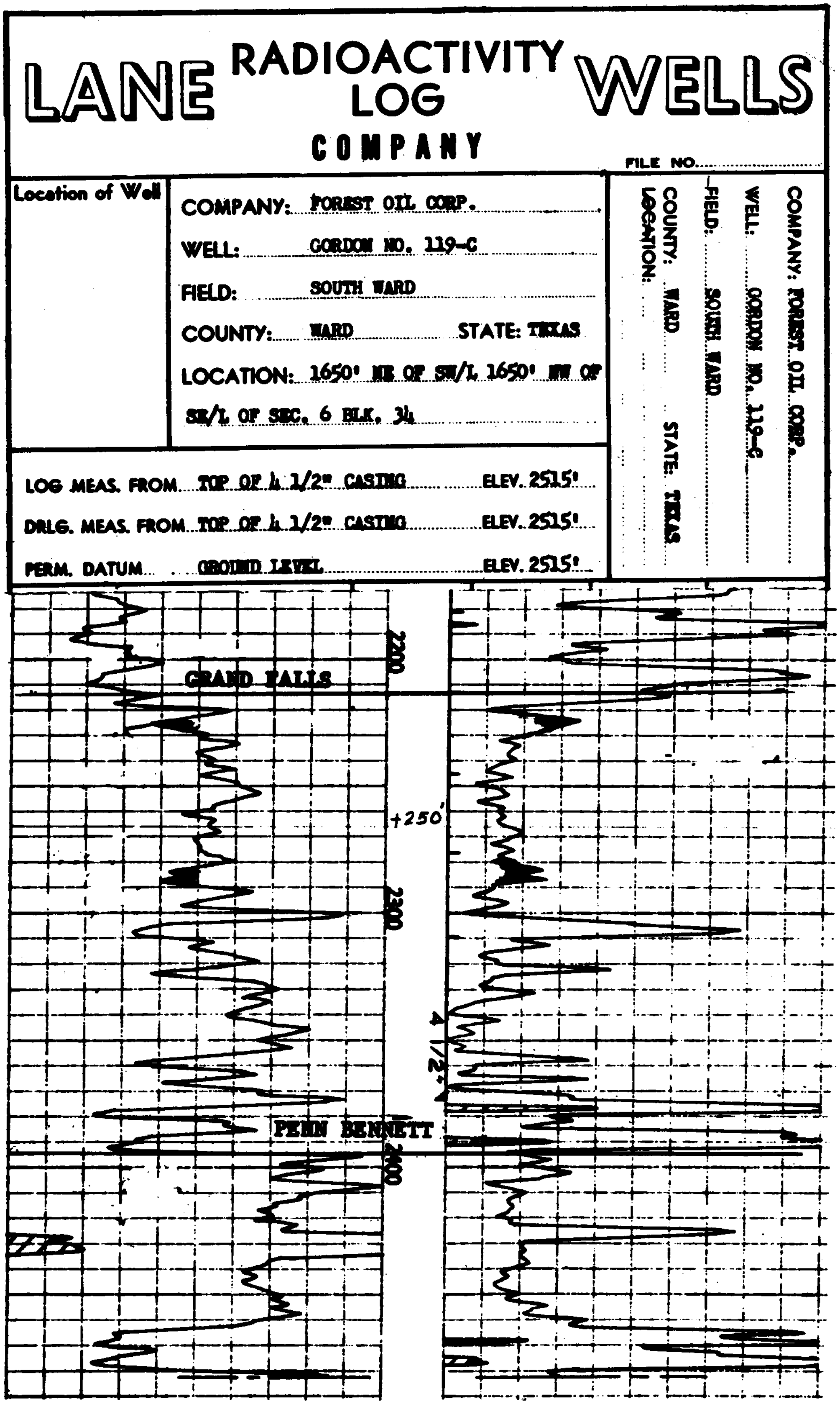

LANE RADIOACTIVITY LOG WELLS
COMPANY
FILE NO.
Location of Well
COMPANY: FOREST OIL CORP.
WELL: GORDON NO. 119-C
FIELD: SOUTH WARD
COUNTY: WARD STATE: TEXAS
LOCATION: 1650' NE OF SW/L 1650' NW OF
SE/L OF SEC. 6 BLK. 34
LOG MEAS. FROM TOP OF 4 1/2" CASING ELEV. 2515'
DRLG. MEAS. FROM TOP OF 4 1/2" CASING ELEV. 2515'
PERM. DATUM GROUND LEVEL ELEV. 2515'
COMPANY: FOREST OIL CORP.
WELL: GORDON NO. 119-C
FIELD: SOUTH WARD
COUNTY: WARD STATE: TEXAS
LOCATION:
2200
GRAND FALLS
+250'
2300
4 1/2"
PENN BENNETT
2400

Fig. 2

Table II is an outline of primary and waterflood recovery efficiencies. The A. B. Gordon lease contained 22,230,000 bbl of rock pore space and initially contained 16,517,000 bbl of reservoir oil or 13,594,000 bbl of stock tank oil. The Penn Bennett primary recovery of 2,227,000 bbl was therefore a recovery of 10 per cent of the pore space or 16.4 per cent of the original stock tank oil in place (OSTOIP).

TABLE II
PRIMARY AND WATERFLOOD PERFORMANCE
A. B. GORDON LEASE

Primary Recovery

2,474,000 bbls. total recovery. 90% from Penn Bennett or 2,227,000 bbls.

2,227,000 ÷ 22,320,000 (total voids) = 10% or Penn Bennett Primary Recovery = 10% of porosity.

OR

22,320,000 B/void — water saturation 26% (5,803,000) equals 16,517,000 bbls. OROIP. 16,517,000 ÷ 1.215 (FVF) = 13,594,000 OSTOIP. 2,227,000 ÷ 13,594,000 = 16.4% or primary production = 16.4% of OSTOIP

At Start of Waterflood

13,594,000 — 2,227,000 = 11,367,000 bbls. STOPI or 83.6% OSTOIP.

Waterflood Recovery

5,500,000 bbls. or waterflood recovery 5,500,000 ÷ 13,594,000 OSTOIP or 40.5% of OSTOIP.

OR

Primary and waterflood recovered 56.9% OSTOIP

OR

5,867,000 bbls. STO remain in reservoir.

Recovery Efficiency

Assuming a 20% residual oil saturation after waterflood then 20% x 22,320,000 = 3,464,000 bbls. left in reservoir as residual oil saturation. However, this would be oil with an estimated FVF of 1.05 or 4,251,000 stock tank barrels. 5,867,000 barrels — 4,251,000 barrels = 1,616,000 barrels to be accounted for.

5,500,000 ÷ 1,616,000 = 7,116,000 equals oil theoretically recoverable with 100% sweep efficiency.

5,500,000 ÷ 7,116,000 = 77.3%

OR

combined horizontal and vertical sweep efficiency equals 77.3%

Waterflood recovery of 5,500,000 bbls is a recovery of 40.5 per cent of the original stock tank oil in place and the combined primary and waterflood recovery is 56.9 per cent of original stock tank oil in place.

This combined recovery leaves 5,867,000 bbl of stock tank oil remaining in the reservoir. Assuming a 20 per cent residual oil saturation after waterflood (based on laboratory FLOOD POT TESTS) then 4,464,000 bbl would be left in the reservoir as residual oil saturation. This would be oil with an estimated formation volume factor of 1.05 and therefore would be 4,251,000 bbl of stock tank oil leaving 1,616,000 bbl of stock tank oil to be accounted for.

The 5,500,000 bbl recovered by waterflood plus the 1,616,000 bbl would be the amount of oil theoretically recoverable by waterflood with a 100 per cent sweep efficiency. The 5,500,000 bbl divided by the 7,116,000 bbl theoretically recoverable gives a combined horizontal and vertical sweep efficiency of 77.3 per cent. I believe this is a reasonable sweep efficiency for this reservoir although it might be somewhat high considering the irregular 5-spot pattern employed on the west end of the lease. This pattern irregularity was in part the result of starting out with a 10-acre pilot and then expanding to 20-acre 5-spots.

WATERFLOOD HISTORY

Water injection of Forest's A. B. Gordon Lease (Fig. 3) and Table III commenced in August, 1949. The first production increase was noted in December, 1949 from the two enclosed 10-acre 5-spots. A year later the 20-acre expansion began and by 1952 the A. B. Gordon lease was essentially developed. The maximum daily production was 2,680 bbl reached in November, 1952.

TABLE III
WATERFLOOD DATA
A. B. GORDON LEASE

Productive Acres	600
Waterflood Oil Recovery to 1/1/66 bbls.	5,472,569
Waterflood Water Production to 1/1/66 bbls.	23,684,217
Water Injection to 1/1/66 bbls.	39,469,603
Waterflood pattern	20 acre 5-spot
Number Injection Wells (maximum)	36

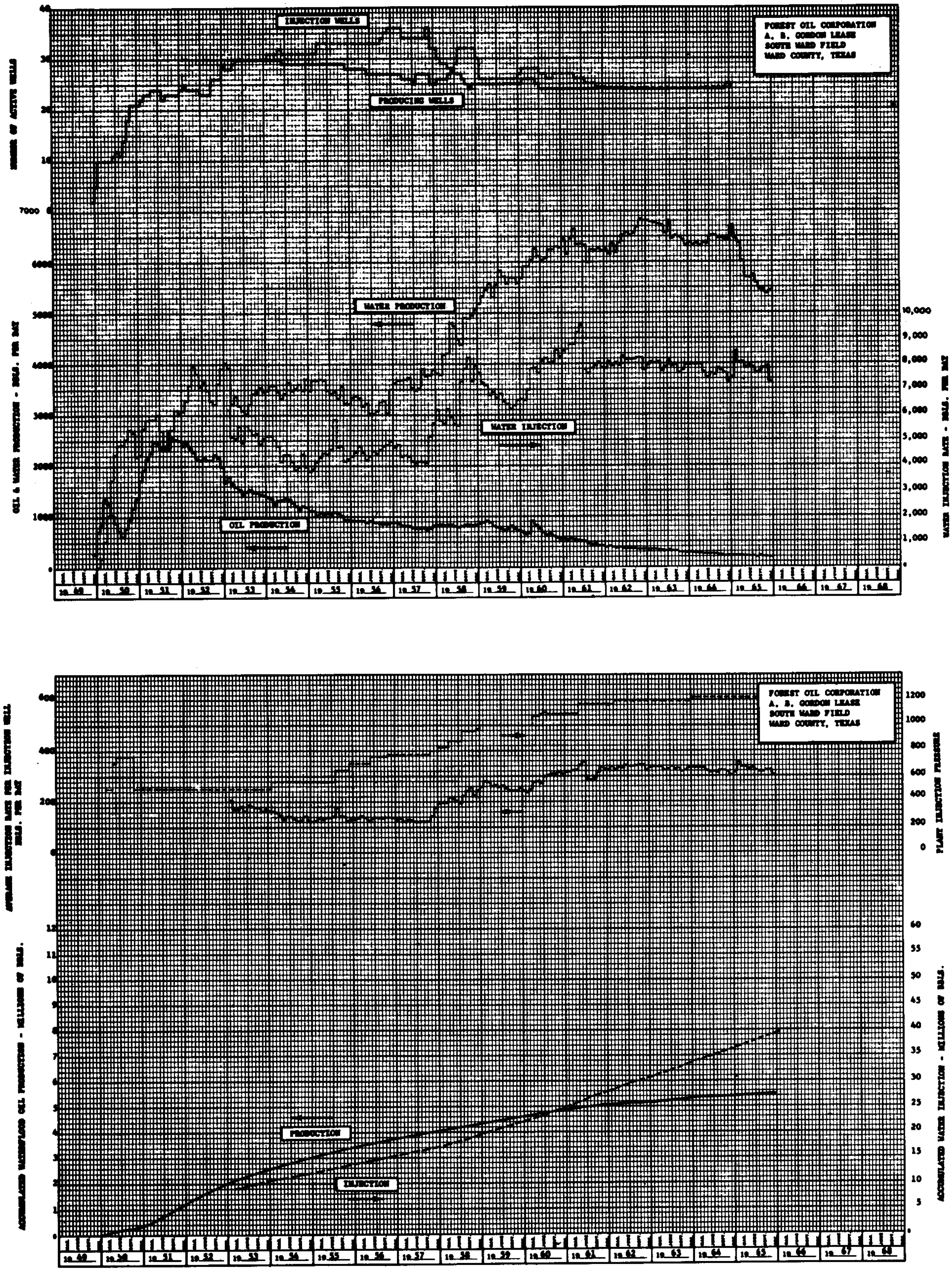

INJECTION WELLS
PRODUCING WELLS
FOREST OIL CORPORATION
A. B. GORDON LEASE
SOUTH WARD FIELD
WARD COUNTY, TEXAS
WATER PRODUCTION
WATER INJECTION
OIL PRODUCTION
NUMBER OF ACTIVE WELLS
OIL & WATER PRODUCTION - BBLS. PER DAY
WATER INJECTION RATE - BBLS. PER DAY
PRODUCTION
INJECTION
FOREST OIL CORPORATION
A. B. GORDON LEASE
SOUTH WARD FIELD
WARD COUNTY, TEXAS
AVERAGE INJECTION RATE PER INJECTION WELL BBLS. PER DAY
PLANT INJECTION PRESSURE
ACCUMULATED WATERFLOOD OIL PRODUCTION - MILLIONS OF BBLS.
ACCUMULATED WATER INJECTION - MILLIONS OF BBLS.

Fig. 3

Number Producing Wells (maximum)	33
Water Supply	Pleistocene Gravels
Salt Water Disposal	Rustler Formation
Reservoir Pore Volumes Injected	1.8
Ratio Water Injected to Oil Produced	7.2 to 1
Water Cut 1/1/66	97
% of Ultimate Waterflood Oil Produced to 1/1/66	96
Cumulative Operating Cost Per Gross Bbl. to 1/1/66 (approx.)	$.65
Cumulative Development Cost Per Gross Bbl. to 1/1/66 (approx.)	$.40

Injection wells were originally completed with casing set on top of the Penn Bennett with the pay sections shot, perforated liner run and gravel packed back into the casing. Later these wells were cleaned out and cement or plastic lined tubing set on a packer in the bottom of the casing.

Most of the producing wells were completed with casing set on top of the Yates with a liner to T.D. so that both the Grand Falls and Penn Bennett zones were open to production.

Injection water was obtained from shallow pliestocene gravel wells in the immediate area of the lease. As the produced water volumes increased, the produced water was treated in an open system, filtered, and injected. However, problems created by this water were so severe that it became more economical to use the well water alone and to dispose of the produced water into the Rustler formation. This formation has accepted the produced water readily with only periodic acid treatments required.

To date approximate costs have been $.40 per gross bbl for development and $.65 per gross bbl for operating expenses. At the time economic limit is reached it is estimated that cumulative operating costs will have increased to $.71 per gross bbl with no change in the development cost.

The lease is now producing 190 BPD at 97 per cent water cut and is still producing at economic rates.

PERFORMANCE COMPARISONS

The individual well primary and waterflood production and the large number of wells cored (25) make the A. B. Gordon a good subject to determine of what value primary production and certain core analysis data are in predicting waterflood results.

PRIMARY PRODUCTION

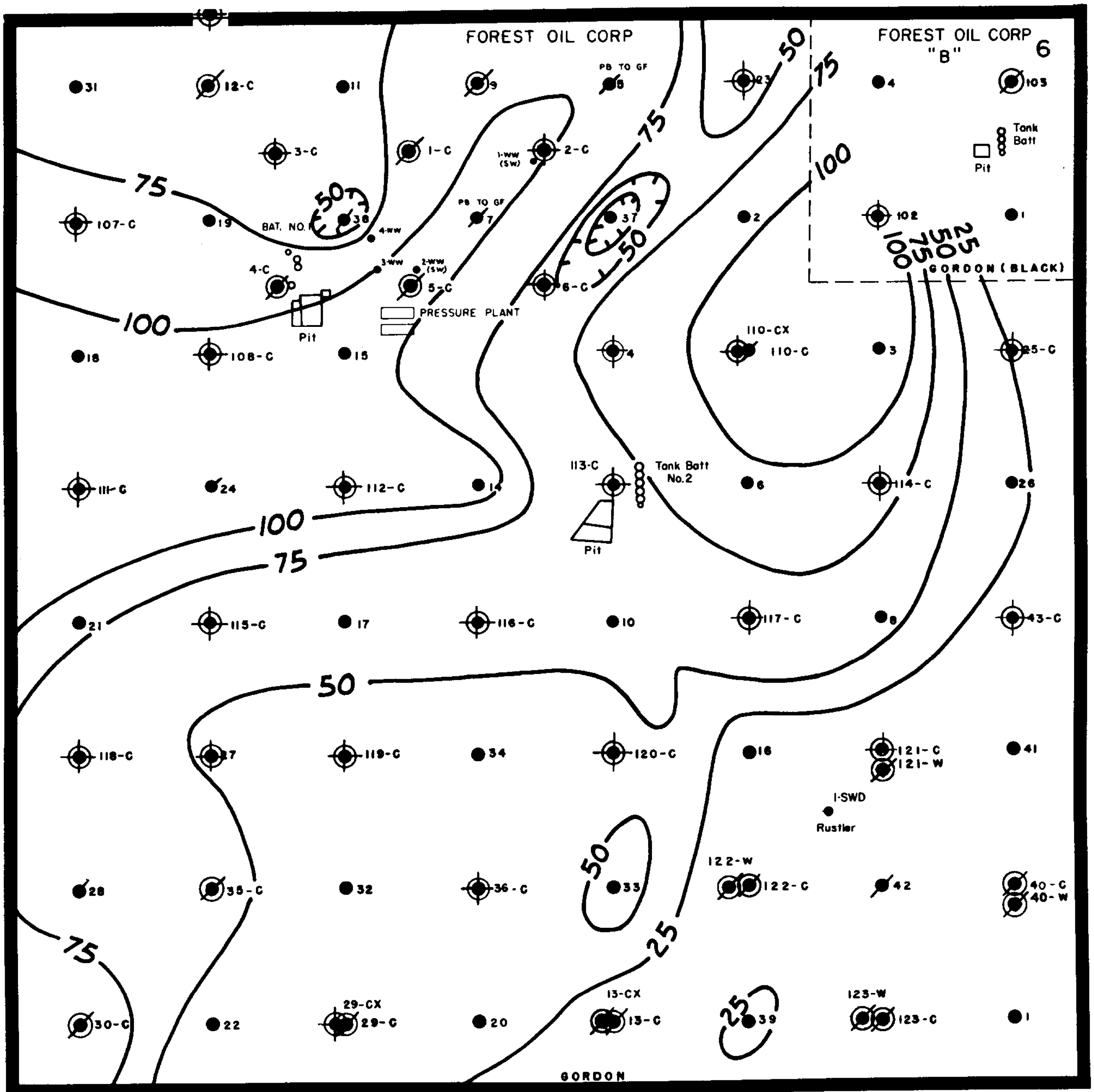
The cumulative primary and waterflood production maps (Figs. 4 and 5) were used for this comparison. The producing wells with a reasonably complete primary and waterflood production history were grouped according to their primary production into the lowest, middle and upper thirds. The results, in terms of waterflood to primary recovery ratio, were respectively for the lower middle and upper thirds, 4.5, 3.0 and 2.5 to 1. These results would imply that caution must be applied in using an across-the-board waterflood to primary rule of thumb. Two factors that may account for the spread in ratio on this lease are that some of the low primary is probably the result of moderately late drilling and some of the high waterflood production from poor primary recovery areas is the result of waterflood drive oil migrating into the tighter edge areas. It is also of note that the individual well ratios varied from 6.6 to 1 waterflood recovery to primary to a waterflood recovery slightly less than primary.

STRUCTURE

As can be seen by a comparison of the structure map (Fig. 6) on the top of the Yates with the waterflood recovery map there is no significant correlation although the better production is reasonably high on structure. Structure is not important to the Penn Bennett pay because neither a gas cap nor edge water are factors in the vicinity of this lease.

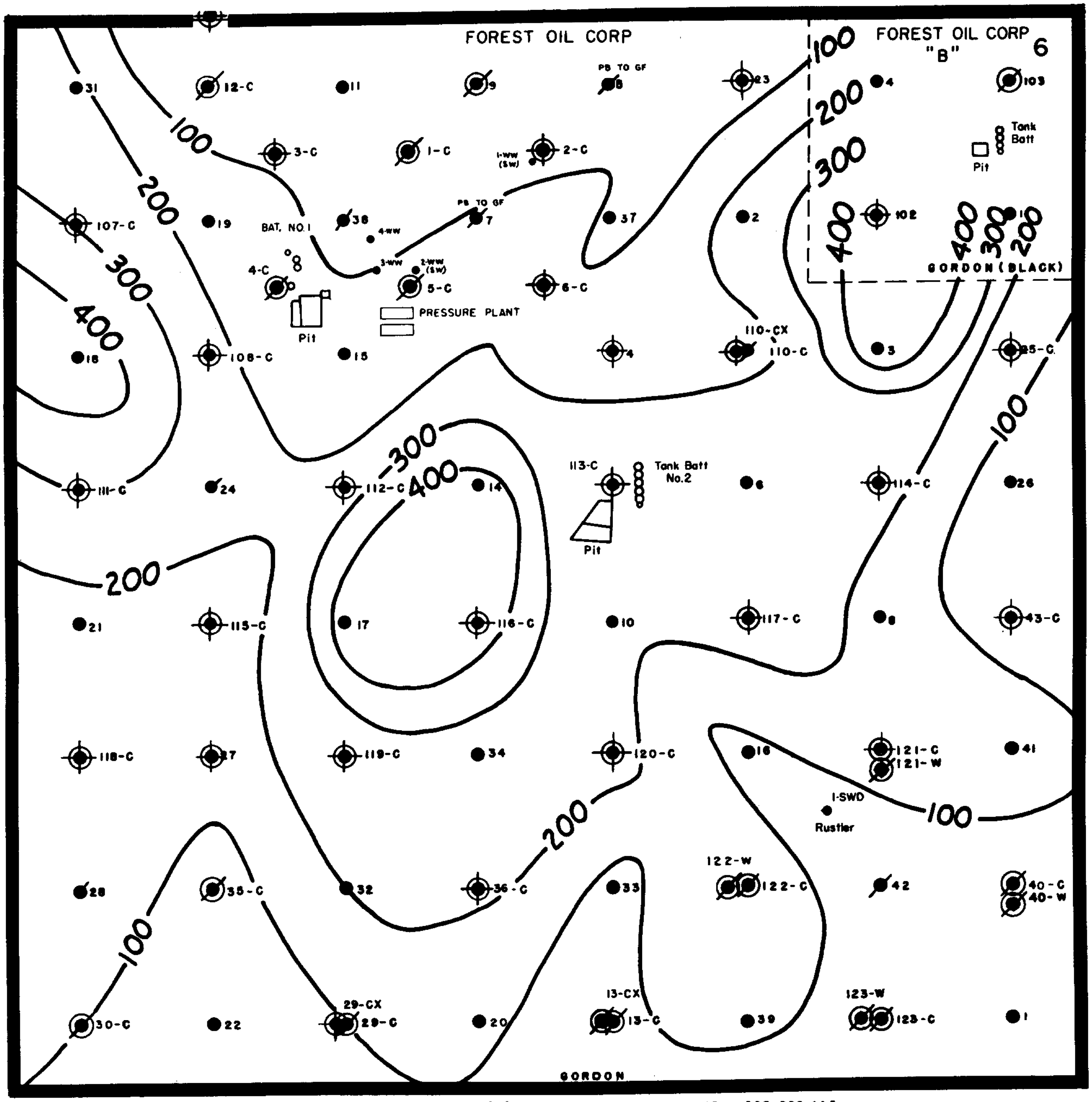
PAY THICKNESS

A defintie correlation of pay thickness (Fig. 7) and waterflood recovery is evident from a comparison of the respective maps. Another map prepared, but not shown, of porosity feet shows an even better correlation than pay thickness alone. This would indicate that where the sand is thicker it also has better porosity.



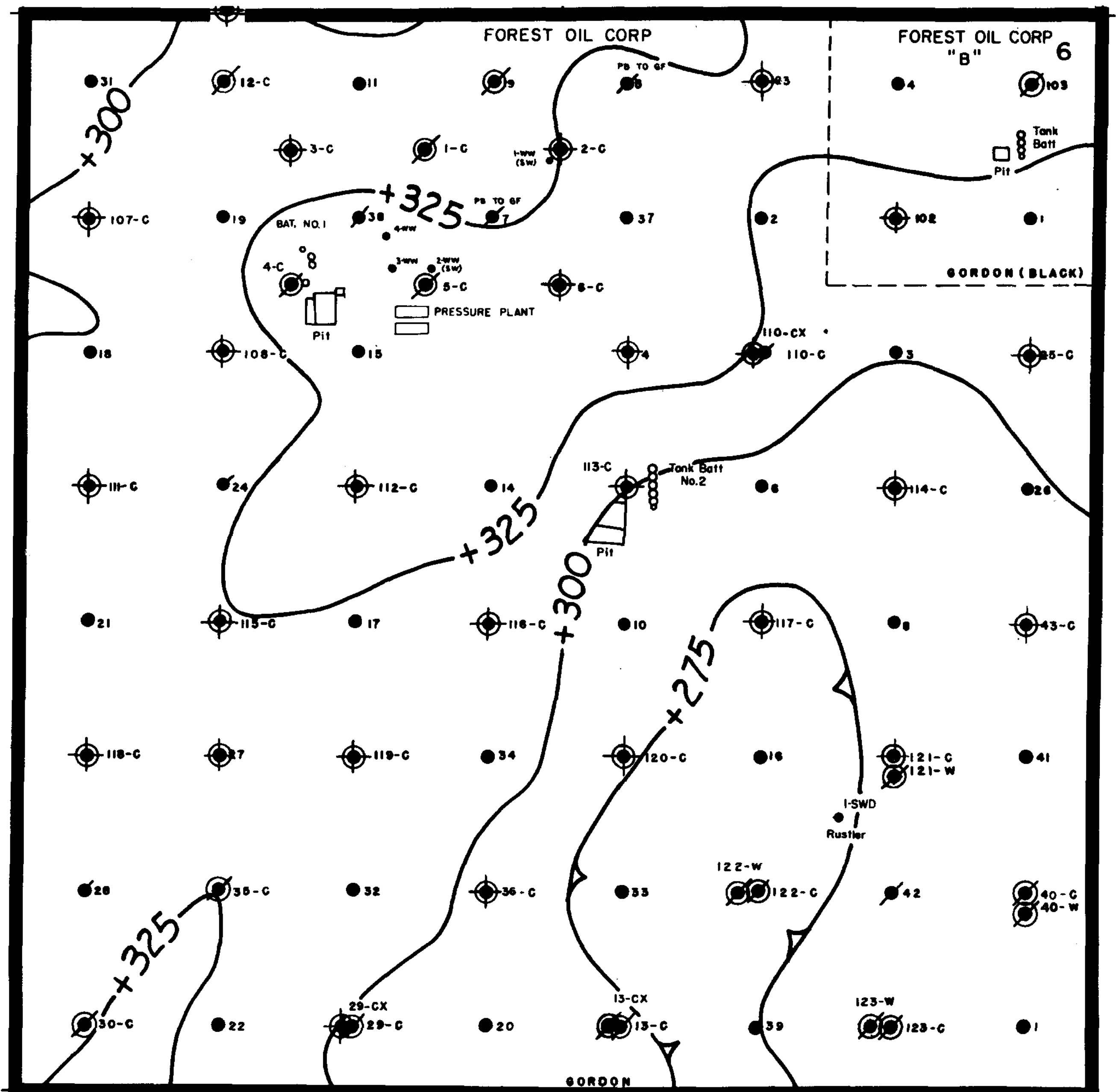
CUMULATIVE PRIMARY RECOVERY **CONTOUR INTERVAL = 25,000 BBLS.**

Fig. 4



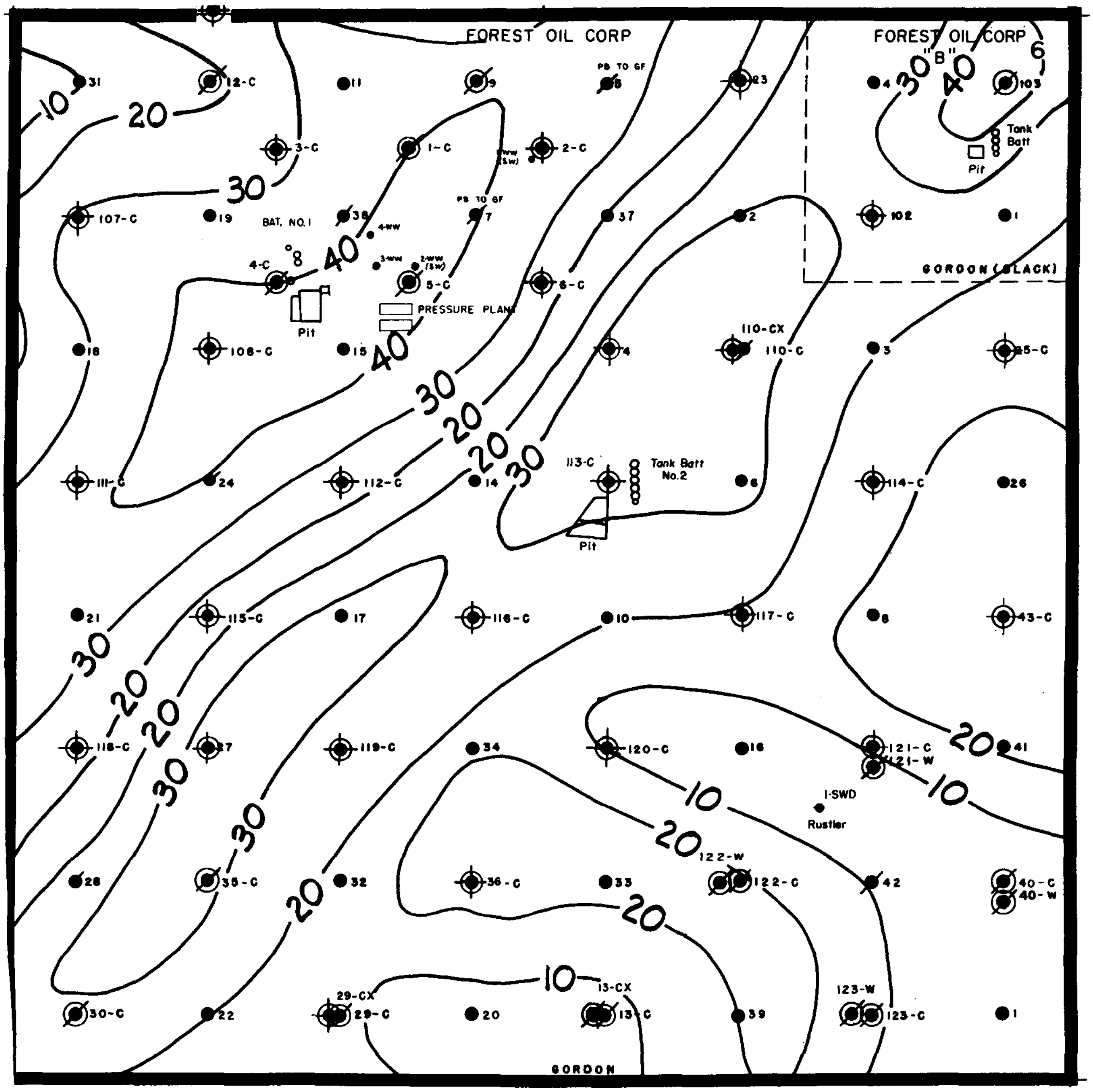
CUMULATIVE WATERFLOOD RECOVERY TO 1/1/66 CONTOUR INTERVAL - 100,000 bbls.

Fig. 5



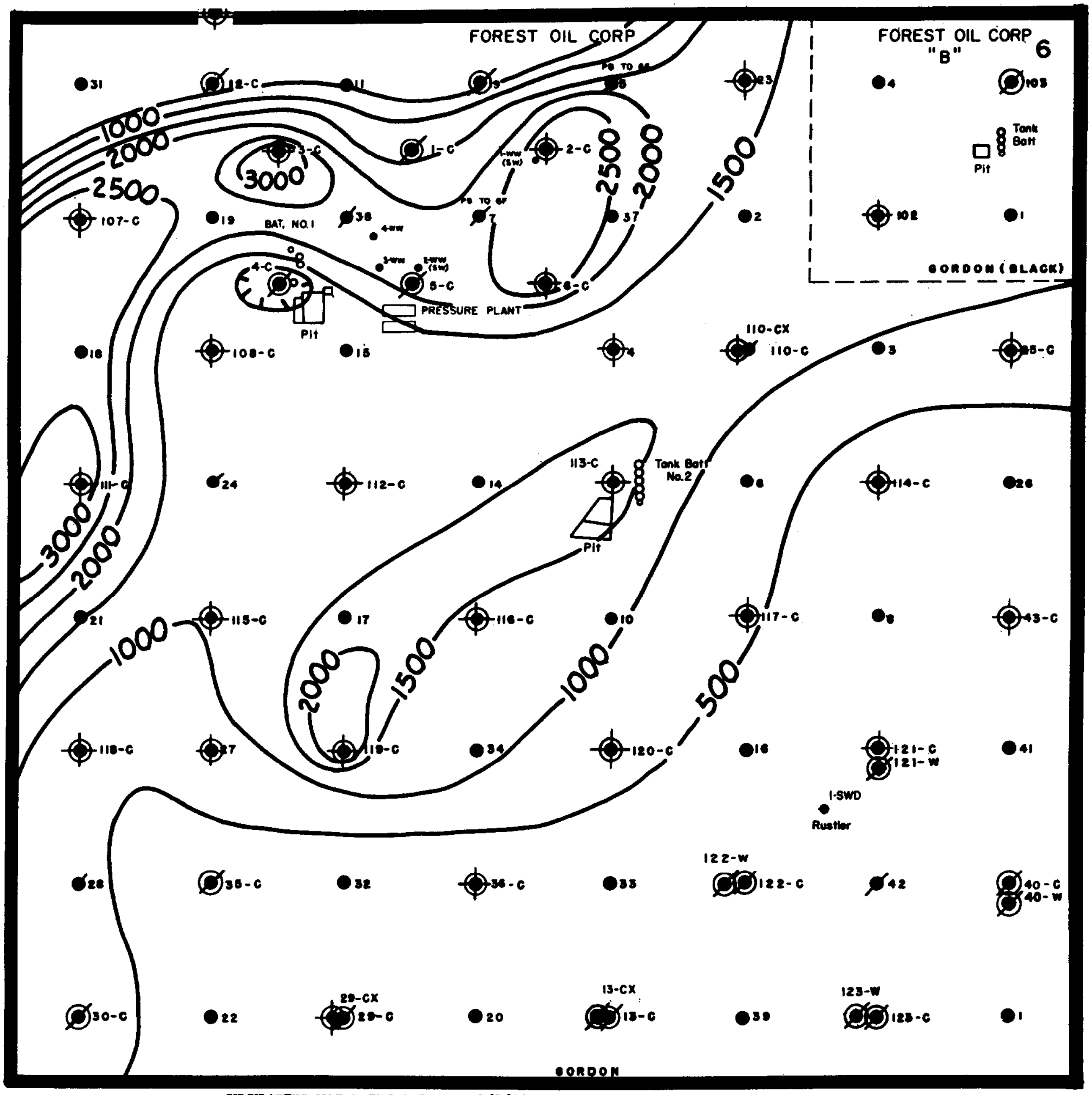
STRUCTURE TOP OF YATES FORMATION CONTOUR INTERVAL 25'

Fig. 6



PAY SAND THICKNESS PENN BENNETT SAND COUNTOUR INTERVAL = 10'

Fig. 7



CUMULATIVE WATER INJECTION TO 1/1/66 CONTOUR INTERVAL - 500,000 bbls.

Fig. 8

WATER INJECTION PERFORMANCE

Although water injection performance (Fig. 8) is not a criterion that can be applied before the start of a flood it is useful in analyzing what has happened to a flood. A comparison of the water injection map with the one of waterflood recovery shows only fair agreement. One area of notable disagreement is in the area of the initial pilot flood. This area has had substantially above average injection but below average waterflood production. It appears that water has travelled beyond the 5-spot boundaries in this area and moved oil ahead of it. It also appears that the somewhat higher than expected oil and total fluid production in the east corner of the lease is a result of water from the better injection areas moving into this part of the lease because of pressure differentials resulting from low injection in the eastern injection wells.

CONCLUSIONS

We have seen from Table II that the standard volumetric computation shows good agreement with the actual results obtained, although it must be borne in mind that 25 core analyses were available from this 600 acre tract to determine the necessary reservoir parameters. If this volume of information is available, a waterflood prediction based on a volumetric study is sound.

The use of a waterflood to primary ratio appears dangerous to apply without a careful look at the time a well or lease was drilled and into the possible effects of oil migration resulting from lack of uniform permeability or order of development.

A carefully researched and constructed pay thickness map appears to be a sound basis for determining relative waterflood recoveries in a reservoir of this type, but permeability variation and the order of waterflood development still must be considered.

The structure is not a significant factor in the waterflood performance of a reservoir of this type.

Unfortunately, perhaps, the conclusion that must be drawn is that no one yardstick could be relied on to predict accurately waterflood results for all areas of this one lease. However, the several methods of comparison taken together offer a reasonable chance to make an accurate prediction.