WATERFLOODING THE GRAYBURG FORMATION ON THE J. L. JOHNSON "AB" LEASE: EXPERIENCE IN THE JOHNSON FIELD

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ABSTRACT

The Grayburg formation in the Johnson field, Ector County, Texas, is a more complex reservoir than originally believed. Poor response from waterflooding the J. L. Johnson "AB" lease with 40-acre five-spots led to development with 20-acre line-drive patterns. This caused a substantial production increase. Infill drilling has lead to the discovery of random, anhydrite-filled sections which act as barriers to flow. They are probably interconnected and may be the cause of poor response to injection on wide spacing. Anhydrite barriers may exist both in other parts of the Johnson field and in surrounding fields. These barriers could play an important role in determining how other waterfloods are designed.

INTRODUCTION

Poor response to waterflooding with 40-acre five-spot patterns prompted ARCO Oil and Gas Company to undertake a major infill drilling program on the J. L. Johnson "AB" lease in the Johnson field of west Texas. As might be expected, closer spacing increase production significantly. It also led to the discovery of random, anhydrite-filled porosity areas in the entire zone under waterflood. These areas have small lateral dimensions but probably wind through the unit in meandering channels created by leaching ground waters after the structure was formed. They act as barriers to flow and are the probable cause for the poor response on wide spacing.

LOCATION

The Johnson field is located on the eastern edge of the Central Basin Platform of the Permain Basin in Ector County, Texas. As shown in Fig. 1, it encompasses parts of 26 sections in Blocks 42 and 43, Township 1 South, T&P RR Co. Survey and is bounded on the north by the North Cowden field and on the south by the Foster field. All three fields produce from the Grayburg formation. The J. L. Johnson "AB" lease is an 840-acre 100% working interest lease in Sections 37 and 48, Block 43, and Section 43, Block 42, T-1-S, operated by ARCO Oil and Gas Company.

PAY DESCRIPTION

The Grayburg formation is the productive interval and is found at about 4150 ft on the lease. As Fig. 2 shows, the Grayburg is a Permian age dolomite. Fig. 3 is a type log of the Grayburg pay found in the J. L. Johnson "AB" No. 70 WIW (water injector well). Table 1 describes each zone. The upper pay is a 10 to 15 ft thick sandy dolomite. Porosity averages 10 to 15% and permeability is 1 to 2 md. Continuity is erratic, with porosity in the zone completely missing at times.

The main pay is a tight dolomite. Porosity ranges from 1 to 15%. The geometric average permeability to liquid is 0.6 md. Continuity is very unpredicatable. The formation correlates between wells, but parts or all of the porosity development can disappear completely from one well to the next.

The lower pay is a porous, permeable, sandy dolomite which is found throughout the area. Porosity is typically 10 to 15% and permeability is 8 to 10 md. This zone was productive once, but it has been flooded out over the years and is now water bearing.

The lower dolomite resembles the main pay except that it is wet. This zone does not appear ever to have been productive on the "AB" lease.

Currently, only two zones, the upper pay and the main pay, are under flood. Although the gamma ray curve indicates shale streaks through the interval, cores contain only minute quantities of shale. Radioactive dolomites are causing the gamma ray kicks. Rock porosity and permeability may vary widely from those properties list in Table 1, depending on location.

FIELD HISTORY

ARCO Oil and Gas Company discovered the Johnson field when it drilled the J. L. Johnson "A" No. 2 in the southwest corner of Section 48. Field rules were established by the Texas Railroad Commission in 1940. Table 2 summarizes the history of the field. As of April 1, 1983, six operators were using 142 producers and 105 injectors. Two operators, ARCO Oil and Gas Company and Cities Service, conduct most of the waterflooding. Cumulative field production was 25,773 MBO as of April 1, 1983.

EARLY COMPLETION TECHNIQUES

Most wells drilled in the 1930's and 1940's were completed open hole. Casing was set at approximately 4000 ft with 250 sacks of cement. Typically, the wells would be drilled to approximately 4220 ft. Total depth was determined with drilling samples. Usually the bottom 100 ft were shot with nitroglycerin. In most wells, the lower pay was penetrated. Initial production from the 15 original wells on the "AB" lease averaged 780 BOPD with no water and a gas-oil ratio (GOR) of 660 cu ft/bbl. Most wells flowed, and the original reservoir pressure was 1700 to 2000 psig at -1000 ft s.s.

EARLY WATERFLOOD PROCEDURES

Waterflooding began on the J. L. Johnson "AB" lease in Aug. 1963. Following standard industry procedures at that time, ARCO Oil and Gas Company converted two shot-hole producers to injectors, drilled three new cased-hole injectors, and began flooding on a peripheral pattern. Fig. 4 shows the flood development for ten years. Peripheral flooding was based on the assumption that the pay sections were continuous over long distances. Numerous floods started in west Texas in the 1960's were peripheral floods.

CURRENT COMPLETION PROCEDURES

Present completion practices on the "AB" lease include drilling all wells to approximately 4250 ft or into the lower dolomite. The open-hole section is logged with a neutron-density-laterolog package. Both producers and injectors are cased to total depth with $5\frac{1}{2}$-in. casing, and cement is circulated. Injectors can be completed with $4\frac{1}{2}$-in. casing, but the Grayburg is so heterogeneous that proposed infill injectors have been known to flow 100 to 200 BOPD. When this happens, the well is produced until it is depleted. Producing inside $5\frac{1}{2}$-in. casing presents far fewer problems than does producing from $4\frac{1}{2}$-in. casing.

Generally, both producers and injectors are perforated with 10 to 15 holes in the upper and main pays. The lowest perforation is 20 to 25 ft above the top of the permeable lower pay. Producers are acidized with 3,000 to 4,000 gallons of 15% hydrochloric acid (HCl) and fractured with 15,000 to 20,000 gallons of cross-linked guar with 5% diesel and 60,000 to 80,000 pounds of 20/40 mesh sand. Treatment is down 2-7/8 in. tubing at 25 bbl/min. Diesel is added to the fracture fluid as a residue-free fluid loss additive. The size of each treatment is based on individual well net pays and on estimated fracture lengths of 200 to 300 ft. Sand concentrations are maintained at 3 to 5 lb/gal to ensure adequate conductivity. Sand is tagged with radioactive material, and after-fracture surveys have shown that most treatments were placed in the desired interval.

The most important design criterion seems to be fracture length. Too short a fracture length may reduce the well's ability to recover reserves, but too long a fracture length has been known to establish communication with old injectors, expecially in the east-west direction.

Injectors are acidized with 5,000 gal of 15% non-elmusified acid (NEA) at 4 to 5 bbl/min, and ball sealers are used to divert fluid to perforations taking smaller amounts of acid. If no significant quantities of oil are produced as the spent acid is recovered, a packer is run on 2-3/8 in. internally plastic-coated tubing, and the well is put on injection. Injection rates are 300 to 400 BWPD at 1100 psig wellhead pressure.

LEASE DEVELOPMENT

Between 1975 and 1980 the lease was developed on 40-acre five-spots. Material balance calculations showed that by 1980 injection into some patterns was exceeding fill-up. The new injectors were cased completions, and temperature surveys showed that most of the fluid was leaving the wellbores in the upper and main pays. Those producing wells which had been good producers early in their lives were depleting and showed no signs of response to injection. Oil production rates were low (5 to 10 BOPD), water production rates were high (50 to 100 BWPD), and the GOR's remained high (500 to 1000 scf/bbl). To reduce the possibility that wellbore damage was preventing response, several old wells were stimulated with acid and fracture jobs. Success was limited and production typically increased for a few months before declining.

Injection profiles were adequate and fill-up was being reached. Lease production increases in the late 1970's were attributed mainly to new wells as development on 20-acre spacing continued. Older producers were not responding and showed no sign of impending response. The steps taken to minimize wellbore damage did not give the desired results. With these facts in mind, ARCO Oil and Gas Company decided to infill drill on ten-acre spacing.

The first well, No. 107, was completed May 8, 1980, and drilling over the next two years developed most of the lease on 20-acre line-drive patterns. Fig. 5 shows development in mid-1982.

Fig. 6 shows lease production since waterflooding began in 1963. As might be expected, 10-acre spacing has increased unit production. The original wells on the lease produced very little water. Current water production indicates secondary reserves, but the high GOR indicates primary production. Also, build-up tests show bottom hole pressures close to original reservoir pressures in some locations. Probably, both primary and secondary reserves are being recovered. By Jan. 1, 1982, ten-acre drilling had resulted in the recovery of 160 MBO of incremental reserves.

This is based on the established unit decline before ten-acre infill drilling began. These are not rate accelerated reserves, but reserves which would not have been recovered without infill drilling.

INFILL JUSTIFICATION

Once 10-acre infill drilling began, it was quickly realized that recoveries of new reserves were much greater than the 2% of the original oil in place (OOIP) as calculated by continuity studies. Two approaches were developed to calculate reserves. In areas of the lease where ultimate primary recoveries were available, the OOIP/acre was calculated using a widely accepted primary recovery factor of 0.16 of the OOIP and the expected drainage area. Secondary reserves were calculated using a secondary to primary ratio of 1:1 over the acreage and interval to be swept.

A second approach was used in newly developed areas or areas of low primary recovery. Volumetric calculations were made using net pay data from offset wells and the reservoir parameters in Table 3. Generally, recoveries were much less than the expected primary recovery of the pattern and at least 16% of the OOIP remained to be recovered by infill drilling and waterflooding.

In some areas, recovery was much greater than 30% of the OOIP. Typically, producers in these patterns were open in the lower pay and had produced secondary reserves from this zone over the years. Infill wells were justified with reserves left in the main pay.

RESERVOIR PARAMETERS

Reservoir parameters are listed in Table 3. The integrated porosity net pay (Øh) of 4.65 porosity-ft is computer generated from a lease Øh map and includes net pay from the upper and main pays only. Connate water (Scw) and residual oil (Sor) values are from special core analyses. Formation volume factors at initial reservoir conditions (Boi) and at the start of waterflooding (Box) are pressure-volume-temperature values. Upper and main pays contain 75% of the OOIP and the lower pay contains 25% of the OOIP. Total OOIP for the unit calculated volumetrically is 23,570 MBO. Recovery to the start of waterflooding in Aug. 1963 (Np) was 1341 MBO or only 5.7% of the OOIP. Total recovery (Np and ΔNp) to 4-1-83 is 3823 MBO of 16.2% of the OOIP.

BARRIERS TO FLOW

A better understanding of the reservoir has developed with infill drilling. The discovery of numerous, random, localized areas in which porosity is almost completely lost through the entire pay section has changed the concept of the reservoir.

As the lease was developed on five-spots, it became apparent that the reservoir was not continuous over long distances as was assumed at the beginning of the peripheral flood. Geological analysis at the start of five-spot waterflooding described the reservoir as stratified layers of porosity or lenses interrupted by areas of discontinuities caused by physical and chemical changes in the rock. Any number of lenses might not be continuous from one wellbore to the next. By drilling on closer spacing, the operator might increase the number of lenses open in offsetting wells and thereby increase the recoverable reserves.

Infill drilling on the lease has modified the geological description again. The logs of many wells show almost no net pay in the upper and main pay zones. The Grayburg formation can be correlated in these wells, but the logs show essentially no porosity. Permeability depends on porosity, and the formation in these wells acts as barriers to flow between injectors and producers.

Neutron-density logs were used to record porosity and laterologs measured resistivity. Our experience indicates that a meaningful porosity cut-off can be established by calculating "apparent" and "actual" pay from core samples using a technique described by George and Stiles.[1] Using this technique, porosity cut-offs of 4.5% for the main pay and 10% for the upper pay were established to determine net pay. When the total Øh in the upper and main pays of any well is calculated to be 100 porosity-ft or less, the reservoir is considered to be a "barrier" to fluid flow.

Three characteristics of the barriers are important for understanding waterflood performance. First, logs of some wells show a complete lack of porosity throughout both zones under flood. Porosity may have existed once, but infilling with a dense substance such as anhydrite has occurred. Second, barriers are found in unexpected locations and sometimes are very close to high net pay wells. Third, barriers are small in lateral extent since conventional fracture treatments put the wellbores in communication with more porous part of the reservoir. These characteristics make barriers different from lenses in the formation. Fig. 7 is the net pay map of the J. L. Johnson "AB" lease and shows the wide variations in net pay between wells. The lined areas are known regions of barriers.

Two examples of severe changes in pay quality are presented. Fig. 8 is a cross section in the eastern part of the lease. Well 55 with a log Øh of zero porosity-ft was completed in Jan. 1976 pumping 38 BOPD and 259 BWPD. It had been fractured with 20,000 gal gelled brine water and 40,000 lbs 20/40 mesh sand. For several years the pay quality in the northwest quarter of Section 43 was thought to be extremely poor. In 1980 well 101 was drilled as an injector, and pay quality improved to 1192 porosity-fit over a distance of 813 ft from well 55. The well was acidized and was completed flowing 131 BOPD and 31 BWPD. It is still producing. Later, well 104 was drilled, and Øh changed to 20 porosity-ft over a distance 751 ft from well 101.

Drilling well 101 demonstrated that "poor" areas of the lease may hold substantial reserves. It also indicated that the best method of development is to drill on close spacing. Well 55 showed that barriers are probably small in lateral extent since fracturing through them results in production.

Fig. 9 shows that severe changes in pay quality can be found unexpectedly. Well 115, which penetrates a barrier, was the last well drilled in this cross section. A 600 to 700 porosity-ft pay was expected, but the actual Øh was 30 porosity-ft. As the log shows, porosity has been lost in the upper pay and in most of the main pay. Well 115 showed that barriers can be found as close as 435 ft from good quality wells. It demonstrated that porosity and permeability cannot be reliably projected even to an offset location.

Over a dozen barriers have been found within a mile of the "AB" lease. The neutron-density logging package accurately measures pay quality. Logging has been conducted predominately by two service companies, and both have found barriers as well as high-quality pay. Calibration checks were performed on each tool before and after logging runs to insure proper functioning. Barriers are not the result of tool malfunctions or logging company errors but are real heterogeneities in the reservoir. They may be the primary cause of poor response on wide spacing.

Flow behavior, to some extent, is related to Øh. Barrier-type wellbores show a marked improvement in production after a fracture treatment as opposed to just an acid treatment. Moderate Øh wells, which make up most of those drilled, will produce after acid treatment but require fracture treatments for sustained production. High Øh wells generally flow after only acid treatments and will maintain good production over time.

GEOLOGICAL INTERPRETATIONS

The Grayburg formation in the Johnson field contains varying amounts of anhydrite which fills the pore spaces. A barrier has not been cored, but it is strongly suspected that a barrier is a part of the reservoir in which the pore spaces have been completely filled with anhydrite.

Fig. 10 is a structure map of the "AB" lease. The lease is near the eastern edge of the Central Basin Platform and structure dips to the south and east. Barriers are found randomly at all levels of the structure and are not dependent on structural position.

One can only speculate on the origin and nature of the barriers. Geologists believe they were formed post-depositionally. The reservoir is too thick and the geological time is too long for anomalies to have remained localized in a constantly changing marine environment and to have caused a loss of porosity throughout the entire pay section.

Probably, after dolomitization, ground waters seeped through the area in meandering streams, leached out the existing porosity and replaced it with anhydrite. Barriers, then, are probably not isolated heterogeneities. Instead, they are interconnected, have small lateral limits, and may run through the formation like so many brick walls. The Central Basin Platform was not a geologically stable area, and fracturing may have played a role in the creation of barriers. Presently, infill drilling to closer spacing offers the most hope for overcoming the problems barriers present.

It is not known how widespread barriers are in the Johnson field, but they have been found in the Foster field, also. Conditions may be favorable for their existence in widespread areas of the Grayburg on the Central Basin Platform. If they are as common in other areas as they are on the J. L. Johnson "AB" lease, the design and operation of secondary recovery units will eventually have to account for them.

CONCLUSIONS

1. Anhydrite-filled porosity, which acts as a barrier to flow, exists in at least part of the Johnson field.

2. Barriers may occupy part or all of the pay section. They are small in lateral extent, unpredicatable, and probably are interconnected.

3. Barriers are probably the primary cause of poor response to flooding on wide spacing on the J. L. Johnson "AB" lease.

4. Barriers have been found in other parts of the Johnson and Foster fields and may be more prevalent than is currently realized.

5. Waterflood operations in the Johnson and Foster fields will ultimately have to account for barriers.

REFERENCES

1. George, C. J. and Stiles, L. H., "Improved Techniques for Evaluating Carbonate Waterfloods in West Texas, "J. Pet. Tech. (Nov. 1978) 1547 - 1554.

SI METRIC CONVERSION FACTORS

acre	x	4.046	873	E + 03	=	m^2
B/D	x	1.589	873	E - 01	=	m^3/d
bbl	x	1.589	873	E - 01	=	m^3
cu ft	x	2.831	685	E - 02	=	m^3
ft	x	3.048*		E - 01	=	m
gal (U.S.)	x	3.785	412	E - 03	=	m^3
in.	x	2.540*		E - 02	=	m
psi	x	6.894	757	E - 03	=	MPa
lbm/gal (U.S.)	x	1.198	264	E + 02	=	kg/m^3
mile	x	1.609	347	E + 00	=	km
scf/bbl	x	1.801	175	E - 01	=	std m^3/m^3

* conversion factor is exact

Table 1
Pay Characteristics

Zone	Porosity %	Permeabiltiy (K_L) (md)	Description
Upper Pay	10-15	1-2	Sandy dolomite Erratic continuity
Main Pay	1-15	0.6	Tight dolomite Unpredictable continuity
Lower Pay	10-15	8-10	Sandy dolomite Very continuous
Lower Dolomite	1-15	0.6	Same as main pay But usually wet

Table 3
Reservoir Parameters

A = 840 acres

Integrated Øh = 4.65 porosity-ft (main pay and upper sandy dolomite)

Scw = 0.3

Sor = 0.38

Boi = 1.2 RB/STB

Box = 1.1 RB/STB

Lower Pay is 25% of Total Pay

OOIP (total) = 23,570 MBO

N_p (8-1-63) 1341 MBO or 5.7% recovery

$N_p + \Delta N_p$ (4-1-83) 3823 MBO or 16.2% recovery

Table 2
History Summary - Johnson Field

2-17-37	First well drilled in field. ARCO Oil and Gas Company Johnson "AB" No. 2 potentialed for 137 BOPD and 55 MCFGD.
7-10-40	Texas Railroad Commission adopted operating rules for field. Special Order 8-1703.
9-26-40	Field rules amended by order 8-1921 to permit wells drilled prior to 7-10-40 less than 1320 ft from nearest well to be credited with 40-acre proration units.
9-1-55	Field rules amended by order 8-32112 to eliminate the potential factor in the allocation formula.
9-26-60	Unit agreement for Johnson Grayburg-San Andres Unit to be operated by Cities Service approved by Special Order 8-44,420. Cities authorized to conduct waterflood operations by Special Order 8-44,536.
12-10-62	Zapata Petroleum Corp. and J. D. Hancock Oil Company authorized to conduct waterflood operations in the Grayburg San Andres reservoir under its J. L. Johnson leases by Special Order 8-50,619.
6-18-63	Sinclair Oil and Gas Company (ARCO Oil and Gas Company) Authorized to conduct waterflood operations in the San Andres reservoir under the J. L. Johnson "A" and "B" leases by Special Order 8-52,377.
8-63	Waterflooding operations commenced on ARCO Oil and Gas Company's J. L. Johnson "AB" lease.
5-8-80	First infill well, ARCO Oil and Gas Company's J. L. Johnson "AB" No. 107 completed, flowing 88 BOPD, 72 BWPD, and 60 MCFGD.
4-30-82	Hearing held before the Railroad Commission to amend field rules to permit optional 10-acre proration units.
5-24-82	Field rules amended to permit optional 10-acre proration units.

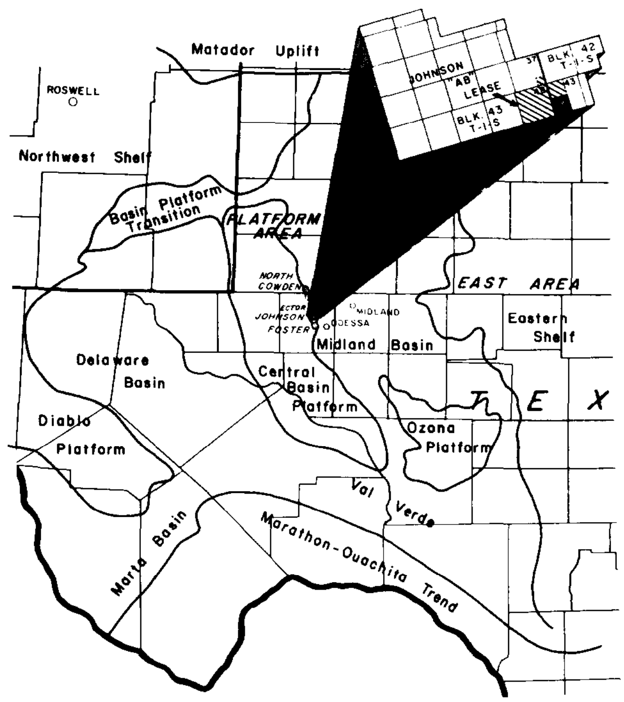

Figure 1 - The Permian Basin

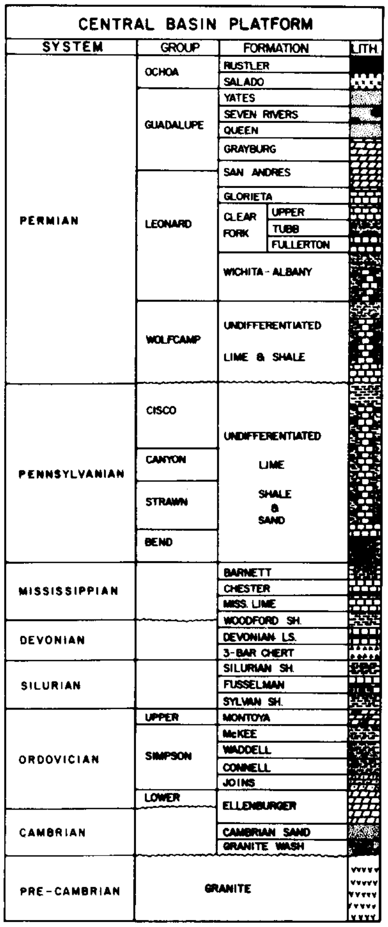

Figure 2 - Geological correlation chart

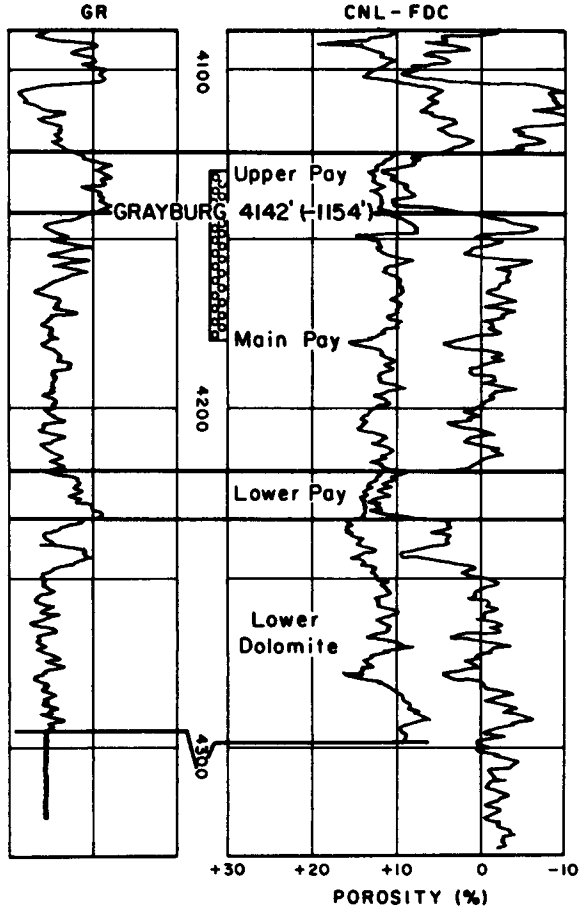

Figure 3 - Type log - J.L. Johnson AB No. 70 WIW

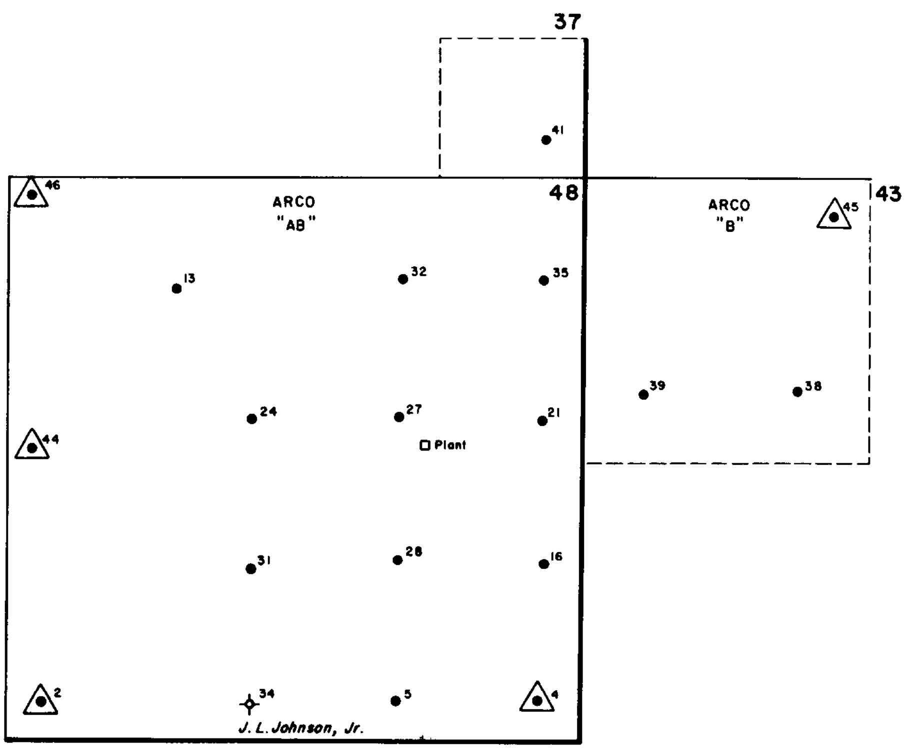

Figure 4 - Initial peripheral flood pattern - April 1965 to Oct. 1975

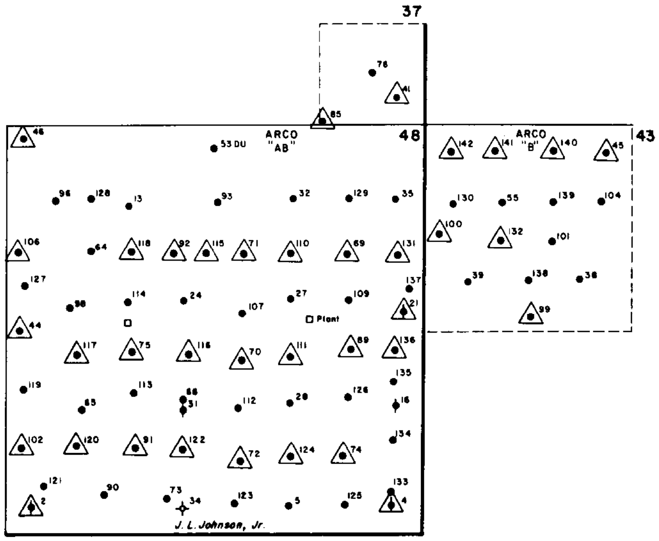

Figure 5 - Current line drive pattern

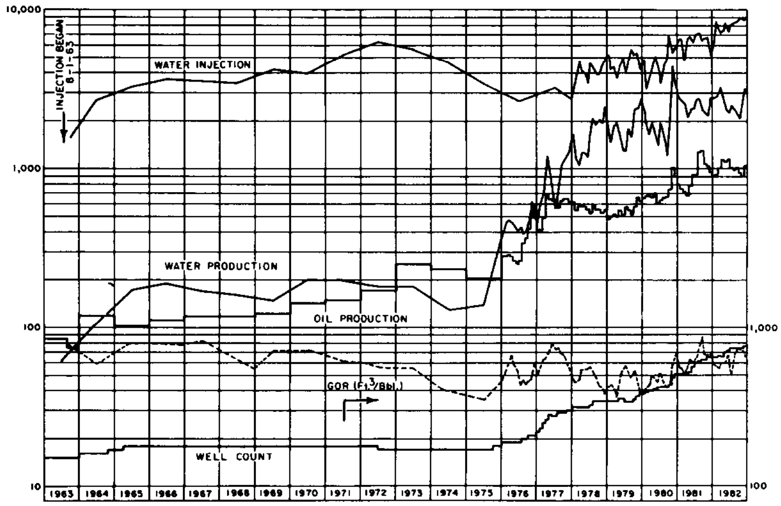

Figure 6 - Performance graph

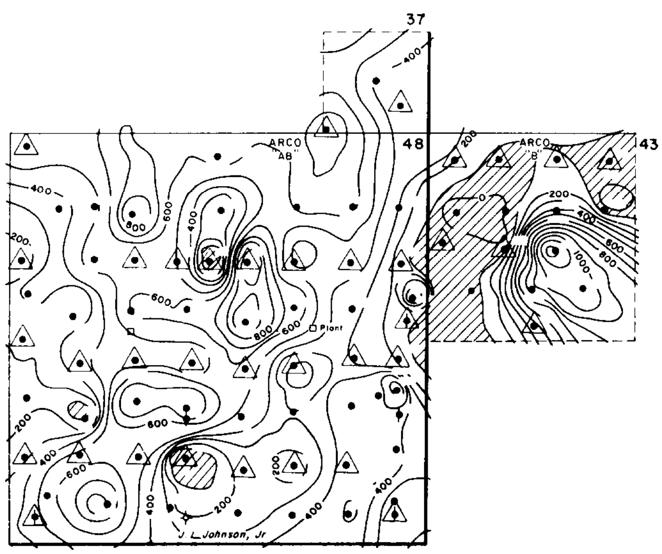

Figure 7 - Net pay map

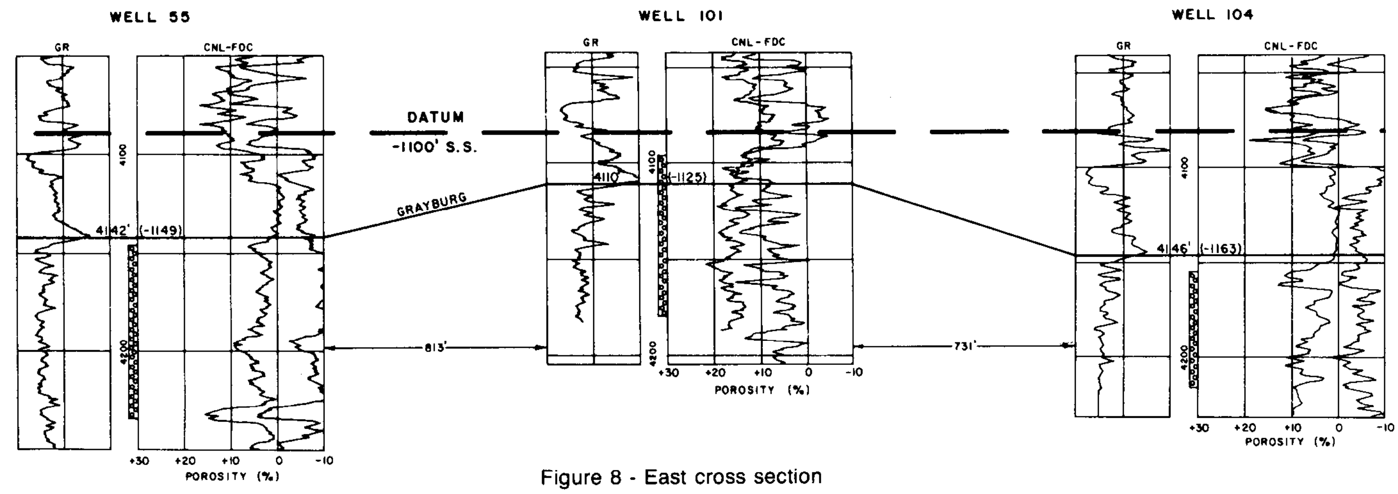

Figure 8 - East cross section

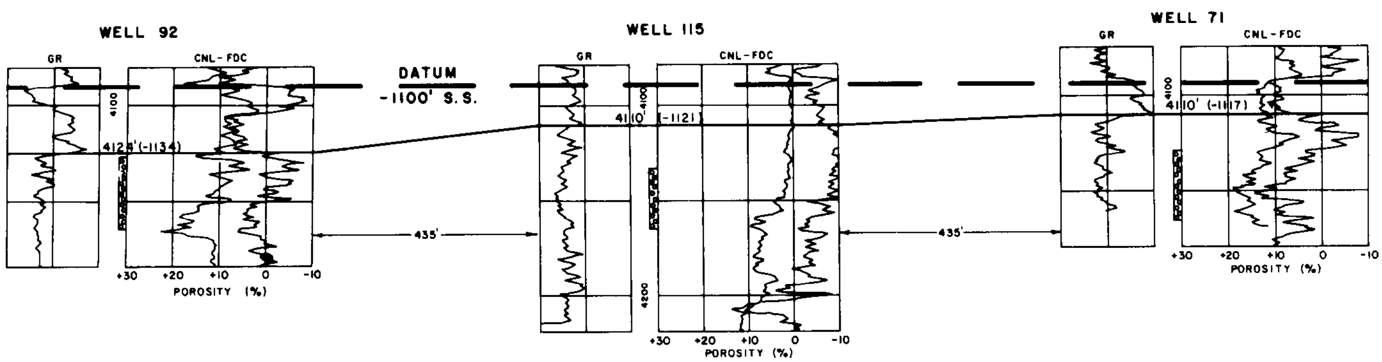

Figure 9 - West cross section

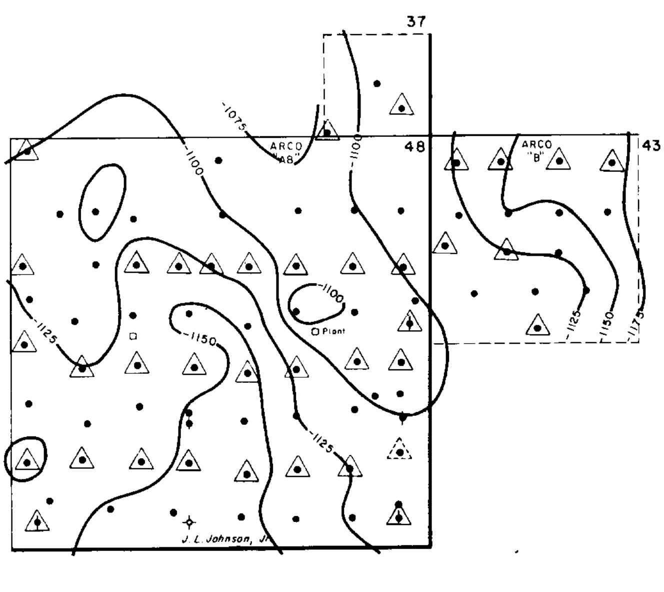

Figure 10 - Structure map - top of Grayburg