A Successful Peripheral Water Flood in a Thin Pennsylvanian Reservoir

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INTRODUCTION

Often, in engineering a prospective water flood it is found that neither the data nor the applicable circulation methods are completely adequate. To some extent, previous experience is applied in these cases and comparison are made to known field case histories. When the fields are, in fact, comparable, the predictions are valid. However, many times comparisons or rules of thumb are not valid and the results can be very expensive.

In the case of Northeast Jones, some operators had condemned water flooding because of poor primary recovery, using the old "rule of thumb" that waterflood recovery would approximate primary recovery.

The area came close to being abandoned without secondary recovery, but a unit was finally formed and water flooding was very successful. Undoubtedly, if present waterflooding experience had been available at the time of decision on the Northeast Jones, there would not have been much doubt regarding water flooding. The value of case histories, then, is in providing an ample range of experiences so that valid comparisons can be made by the engineer for the purpose of prediction. This paper presents an analysis of the history, planning and performance of the Northeast Jones water flood.

RESERVOIR DEVELOPMENT AND CHARACTERISTICS

The Jones Field, shown in Fig. 1, is composed of the Northeast Jones and West Jones areas. Each of these areas was originally considered as a separate field but production performance showed that they should be considered as one. The two areas are in communication but are partially separated by a permeability pinchout in Section 27.

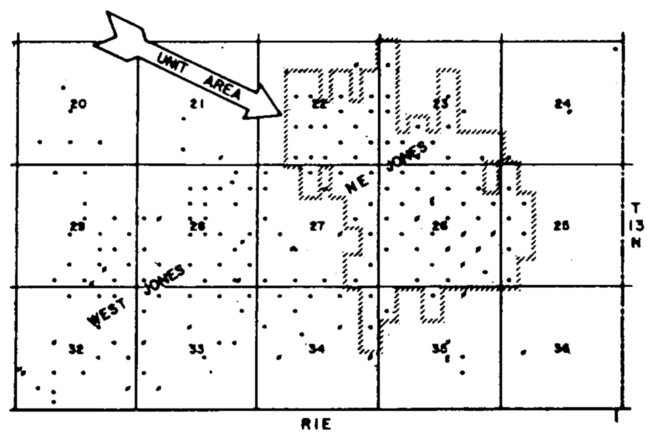

Fig. 1—Jones field map.

The Cleveland Sand reservoir is a stratigraphic trap of Pennsylvanian marine deposition. The reservoir is 4600 ft deep and its producing thickness varies from 4 to 9 ft, averaging 6.5 ft. The reservoir rock is fairly clean, fine-grained sandstone with thin shale streaks scattered throughout. The top and bottom shale barriers are abrupt. Th ereservoir is on a monocline, dipping 40 ft/mile to the west, and is confined in all directions by shale.

The Jones field was discovered in 1939, but originally the Cleveland sand was developed only on the West Jones side of the pinchout in Section 27. Then in Aug., 1945, the Bednar "A" No. 1 (NW NW SW Section 23) was completed as a wildcat at 50 BOPD in the Cleveland sand, opening the Northeast Jones area.

The first year three offsetting wells were completed on 10-acre spacing. The Northeast Jones was then developed on 20-acre spacing until 1949, when development ceased. Development has ceased partially because the boundaries of the field were defined but also because primary production was disappointing and was not paying out drilling costs. A dry hole was never drilled on the eastern boundary. However, the producing wells in this area indicated that the sand was thinning and becoming poorer quality. The other boundaries were all fixed by marginal wells and dry holes.

From 1945 through 1949 more than 70 wells were drilled in the Northeast Jones area, 52 of which were drilled during 1948. Production reached its peak of 3000 BOPD in 1948 and had declined to 150 BOPD by 1952. By 1951, seven of the Northeast Jones producing wells had been plugged and abandoned and many more were temporarily abandoned.

Cores were taken from 13 wells and analyzed with both routine and special tests. Core analysis porosities of the pay section averaged 18.8 per cent, with the maximum core sample porosity being 25.1 per cent. The permeability ranged from 10 to 480 md, with a mean permeability of 160 md. Rock and fluid properties are shown in Table 1. Unsteady-state water-oil relative permeability tests were conducted on two core samples having permeability and porosity approaching the field's averages. These data showed that the average water saturation behind the flood front was expected to be 60 per cent. After analyzing the results of the actual secondary performance, this value seemed to represent the displacement characteristics. Capillary pressure tests were also run on several core samples indicating an average interstitial water saturation of 18 per cent.

A bottom-hole fluid sample was collected in Feb., 1948, from the Tansel Well No. 2 (SW SE SW Section 23). The static bottom-hole pressure at the time of sampling was 1465 psi in the well. A fluid analysis was run in the laboratory and fluid properties were extrapolated to the estimated bubble-point pressure of 1885 psi. The reservoir was probably near bubble-point conditions at time of discovery. The indicated original solution gas-oil ratio was only 314 scf/bbl, the original formation volume factor was 1.14 and the viscosity of the oil at bubble-point conditions was 2.4 cp.

PRIMARY PERFORMANCE

Fig. 2 shows the performance curve for the area included in the Northeast Jones Cleveland sand unit for both primary and secondary recovery operations. As the Northeast Jonts was developed and primary production continued, static bottom-hole pressure was measured in some of the wells at various times in conjunction with gas-oil ratio tests. Although these data were not extensive enough to represent average reservoir conditions, the pressure and gas-oil ratio behavior were qualitatively useful.

Primary performance indicated that the producing mechanism was solution gas drive alone. The reservoir was completely confined and there were no signs of a natural water drive or the presence of a gas cap. At the time of discovery of the Northeast Jones in 1945, the static bottom-hole pressure was 1885 psi. Material balance calculations indicate this was near the bubble-point pressure. The pressure was probably higher and in equilibrium with the West Jones at virgin conditions, but this cannot be verified since actual pressure data are not available for the West Jones The earlier production from the West Jones caused some migration of oil from the Northeast Jones but this is not believed to have been significant. The primary performances of the two areas were about the same.

TABLE 1—PERFORMANCE

	PRIMARY	SECONDARY
Oil Recovery	1,665,052 bbl	3,579,139 bbl
	160 bbl/acre-ft	344 bbl/acre-ft
Producing Wells	72	38
Injection Wells		28
Life	7 yrs	10 yrs
Total Water Injected		15,000,000 bbl

TABLE 2—RESERVOIR DATA

Depth	4,600 ft
Area	1,600 acres
Thickness	6.5 ft
Original ST Oil in Place	10,877,000 STB
Porosity	18.8 %
Water Saturation	18.0%
Permeability	160 md
Original GOR	314 scf/bbl
Oil Viscosity	2.4 cp
Original FVF	1.14

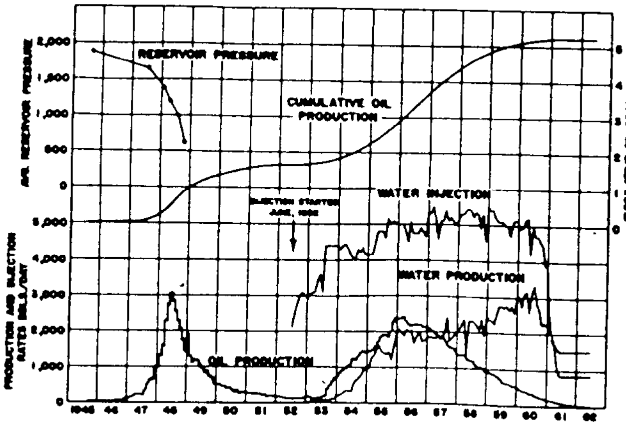

Fig. 2—Northeast Jones performance data.

By the end of 1947, only 20 wells had been drilled and produced in the Northeast Jones, the majority of those having been completed in the latter part of 1947. At the end of 1947, the average reservoir pressure was about 1500 psi. During 1948, 52 wells were drilled, causing reservoir pressure and well productivities to decline very rapidly. The total field oil production peaked at about 3000 BOPD in May, 1948, and had declined to less than 1500 BOPD by the end of 1948.

During 1948, the reservoir pressure declined from over 1400 to less than 500 psi, and the gas-oil ratio increased from 500 to 4000 scf/bbl. As a result of this extremely rapid decline in pressures and productivities, a difference of only a few months completion date in 1948 meant a difference of thousands of barrels of ultimate oil recovery in a well.

After 1947, the ultimate primary recovery from new wells seemed to be almost entirely dependent on the date of completion. Although few wells in the field could be considered profitable, those wells drilled during and after 1948 were particularly unprofitable. Ultimate primary recoveries ranged from over 60,000 bbl from the discovery well to less than 4000 bbl fro mone of the wells drilled in 1949.

Primary recovery was only 15.3 per cent of original oil in place. Although this is relatively low, it compares closely with the performance expected from the fluid and rock properties in the field. This low primary production was responsible for leaving a high oil saturation at the beginning of water flooding, which was probably the most significant factor in the high waterflood recovery.

WATERFLOOD DEVELOPMENT

Discussions regarding the possibility of forming a unit to waterflood the Cleveland sand began in 1949. There were 11 operators in the area, no one of whom had as much as 15 per cent interest. Some operators were hesitant about waterflooding, because existing rules of thumb indicated that water flooding would be uneconomical because primary recovery had been low, because the sand was very thin and because the depth was comparatively great.

Other discouraging facts were the Cleveland sand was of quite variable quality in some other fields, the Cleveland had never been flooded, only limited core data were available for the Jones field, and the wells were on 20-acre spacing.

An outside group became interested in the prospect in 1950 and undertook to negotiate the acquisition, by farm-out and purchase, of enough interests to ensure unitization and flooding. This effort succeeded and in Feb. 1952, the unit became effective, with Lobar Oil Co. as operator. Water injection was started the following June. The unit had minor enlargements in 1955 and 1956, making the final unit area as shown in Fig. 1.

When selecting the injection configuration, one of the primary considerations was to keep development costs as low as possible to minimize risk. This was particularly important in view of the economic losses on primary production and the attitudes toward the field in general. This restriction precluded the use of a pattern flood, since about 10 new wells would have been required in the undrilled areas and in the areas where wells had been plugged and abandoned. To minimize development costs and at the same time maximize recovery, a peripheral flood plan was adopted, as shown in Fig. 3. It was believed that the areas which would not have producing wells, mostly in the southeast portion of the field, would be efficiently swept with this peripheral arrangement. A line of injection wells was placed through the center of the field, actually dividing the field into a north peripheral flood and a south peripheral flood, making the geometry of each part more circular and at the same time increasing the effective field injection capacity.

The unit area was expanded in 1955 to drill a producing well in SE SE SE Sec. 23 which was completed at 314 BOPD with 3 BWPD. It was again expanded in 1956 to drill an injection well in C SE SE Sec. 26, which was needed to supplement the injection rate in the southeastern part of the unit. Two wells were drilled outside the eastern boundary of the unit in 1956. One of these (NE NW SE Sec. 23) produced at high rates but at a high water cut, whereas the other well (SW SW SW Sec. 24) had low productivity in a thinner, poorer quality sand. Neither of these outside wells was profitable.

The water injection station consisted of two triplex injection pumps with a 4800 B/D capacity at 1400 psi, driven by electric motors. Diatomaceous earth filters were used on the fresh water after leaving a 5000 bbl raw water tank. A corrosion inhibitor and bactericide were added to the fresh water throughout the flood life, with occasional down-hole batch treatments of corrosion inhibitor being used in problem-producing wells. Initial injection was begun in 16 wells. Later, additional wells were converted to make a total of 24 active injection wells. Produced salt water was disposed of into one injection well until late 1957, when seven wells were changed from fresh water to produced salt water. injection.

Permeability tests from cores had shown that, although the sand was shaley throughout, the permeability to air, brine and fresh water was essentially the same and no injectivity problems were expected. Fresh injection water was obtained from a shallow sandstone formation. Converting wells to injection was simply a matter of cleaning them out and injecting water through the casing.

WATERFLOOD PERFORMANCE

Less than a year after water injection started, some producing wells began responding. The first wells to respond were the injection well offsets in which water broke through quickly and ultimate secondary recovery was low. The first significant production increase occurred in Sept., 1953, 15 months after injection began. This occurred when some of the second row producing wells began responding and the oil bank pressure was increasing.

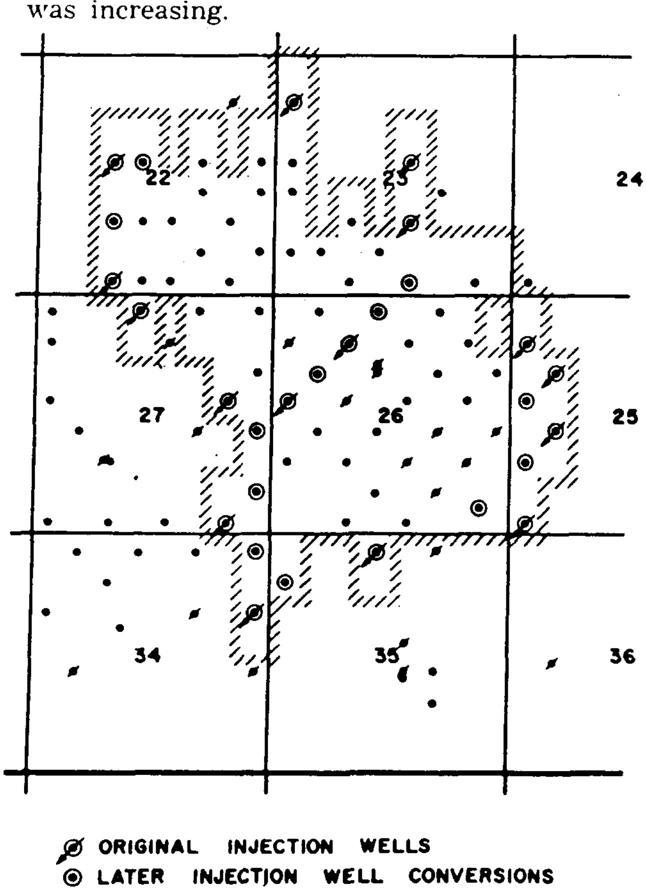

Fig. 3—Northeast Jones Cleveland sand unit, showing well arrangement.

Oil production then steadily increased until the peak production was reached in early 1956. The peak production was coincident with reservoir fill-up which was evidenced by the last producing well responding to injection.

Fill-up occurred in the north and south peripherals at about the same time. Fig. 4 shows a picture of the advancement of the water bank, or two-phase bank, as determined from production data. The evenness of the water bank advancement is a result of both careful control of injection rates in individual wells and of the uniformity of the reservoir. The advancement of the oil bank, now shown here, was equally uniform.

After some of the edge producing wells had become uneconomical because of high water cuts they were converted to injection service. Consequently, the ultimate injection pattern consisted of almost all of the edge wells injecting water. This made the areal sweep of the flood front more uniform and minimized migration off the unit. The citerion for shutting in producing wells with high water cuts was strictly economical. No consideration was given to conserving water in the reservoir other than the cost of injecting and producing the water. Most of the outer producing wells became uneconom-

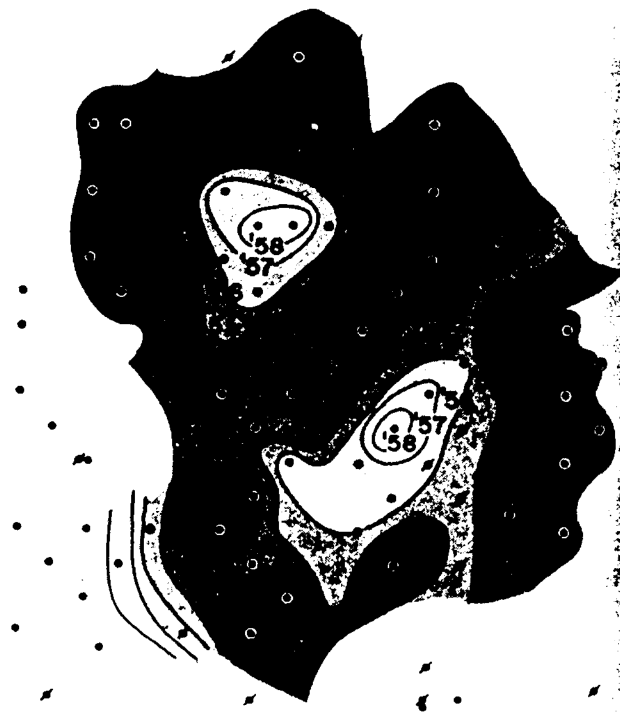

Fig. 4—Advancement of the water front, showing the outline of the water front at consecutive mid-year dates.

ical fairly quickly and the ultimate oil production from them was relatively low.

Fig. 5 shows an interesting comparison of ultimate recovery by wells as indirectly related to their distance from injection wells. To correct for the irregularities of the field, the individual well's recovery is plotted as a function of total reservoir volume swept, or actually, field cumulative injection at the time of breakthrough in that well.

The total effective injection as shown in Fig. 5 has been corrected for the migration and other losses of injection water. The trends in this figure show that the later water broke through in a well, the higher that well's ultimate recovery. For the wells that were still producing from the oil bank, or had not yet produced water, at the time of fill-up, the ultimate recovery as related to effective cumulative injection showed a higher trend than did those wells which were producing water or had been shut in at time of fill-up. This illustrates how the movement of the oil bank toward the center of the field before fill-up adversely affects the recovery of the outer wells. Of the total ultimate secondary recovery, 52 per cent came from only nine of the center wells.

Fig. 6 shows some injection characteristics of the Northeast Jones. In a plot of cumulative total production vs cumulative injection, the intercept of a straight line extrapolation to the absicissa represents the reservoir voidage at the beginning of the flood. The voidage from volumetric calculations was estimated to be 2.76 million reservoir bbl and is represented on the graph by the intercept of the broken line.

The apparent reservoir voidage from the actual production and injection data is shown by the intercept of the solid line in Fig. 6 to be 3.2 million reservoir bbl. The difference in these two figures is interpreted to represent the migration of 435,000 bbl from the Northeast Jones before fill-up to the West Jones.

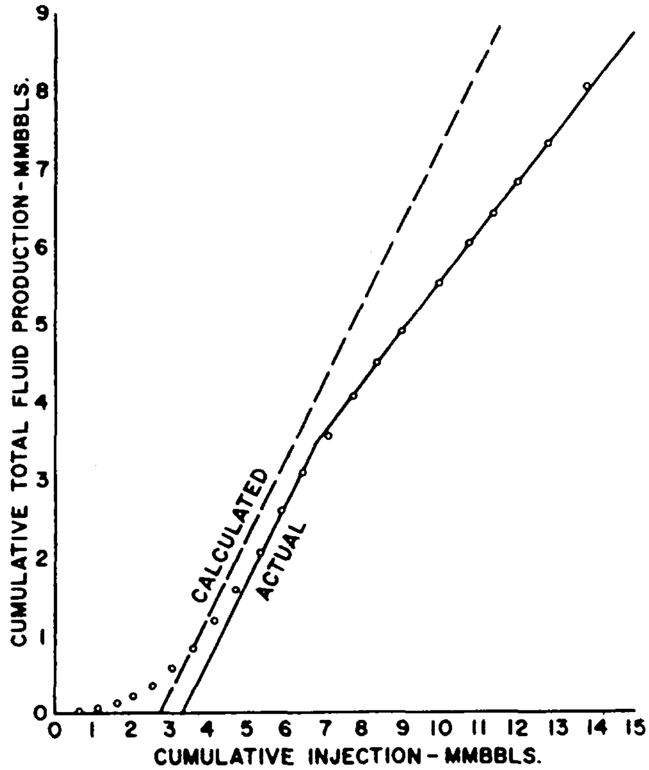

Fig. 6—Injection characteristics—calculated and actual values for fill-up volume (abcissa intercept) and injection efficiency (slope).

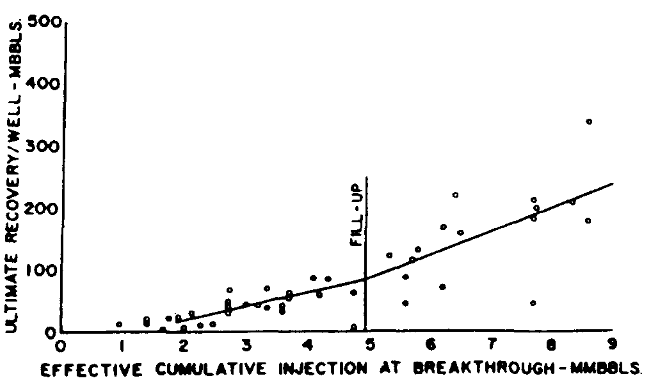

Fig. 5—Plot of the ultimate waterflood recovery of the individual wells as a function of the corresponding effective field injection at water breakthrough.

The West Jones Cleveland sand unit began injection four years after the Northeast Jones and is still in operation. The same type of analysis of the West Jones shows an apparent fill-up volume of 1.058 million bbl less than calculated from volumetric data. This represents 435,000 bbl which migrated to the West Jones before the Northeast Jones fill-up, and an additional 623,000 bbl migrated during the time between the Northeast Jones fill-up and the West Jones fill-up. This meant that about 8 per cent of the Northeast Jones injection migrated to the West Jones during each of these time periods. Physical evidence of this migration taking place was seen in the West Jones wells responding and even producing injected water before the West Jones was formed. Most of the migration probably took place in the south portion of Section 34, where a continuity of wells exists between the two units. Some evidence of migration was seen to the north of this area, but the number of active producing wells available for observation was limited.

As shown by the slope of the line in Fig. 6, the ratio of total production rate to total injection rate approached 1 in the Northeast Jones as fill-up was reached Then this ratio dropped until only 60 to 70 per cent of the injected volume was being produced. The reduction in this injection efficiency was a result of injection capacity exceeding production capacity as producing wells watered out and were shut in. It is not known where this excess injection water went. Some of the water probably left the effective reservoir through vertical or horizontal fractures and perhaps some was lost into other formations through faulty well equipment or completions.

Taking into account the losses of that water which migrated from and otherwise left the reservoir, as described above, only about 11 million of the 15 million bbl injected were effective. This means that only 3.1 effective bbl of water were injected for every bbl of oil recovered.

The ultimate secondary recovery from the Northeast Jones Cleveland sand unit was 3,579,139 bbl. This was 2.15 times the primary recovery. Together, ultimate primary and secondary recovery were 48 per cent of the original oil in place. The secondary recovery amounted to 344 bbl/acre-ft compared to 160 bbl/acre-ft primary. This performance shows the fallacy of predicting secondary recovery from primary performance without proper interpretation of reservoir characteristics.

The ultimate secondary recovery, expressed in barrels/acre-ft, was almost identical for the north and south parts of the field: This tends to indicate that the oil in the areas in the south flood which did not have active producing wells was efficiently swept to the center wells. It is believed that drilling these locations would not have added significant recovery.

The success of secondary recovery was largely attributed to the low primary recovery or the high remaining oil saturation at the beginning of the water flood. In spite of a slightly unfavorable mobility ratio of 1.6, the sweep efficiency seems to have been very high. It is estimated that the combined areal and vertical sweep efficiency was in excess of 80 per cent. The geometry of the reservoir and injection configuration helped improve both area and vertical efficiency. The reservoir rock, although described as shaley, was continuous throughout and had abrupt boundaries. With crossfolw occurring throughout the reservoir, the high ratio of reservoir length to thickness maximized vertical sweep efficiency. The areal sweep efficiency was maximized by the use of nearly circular injection configurations and by the careful control of injection rates in individual wells.

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