Lovington (San Andres) Waterflood— A Case History

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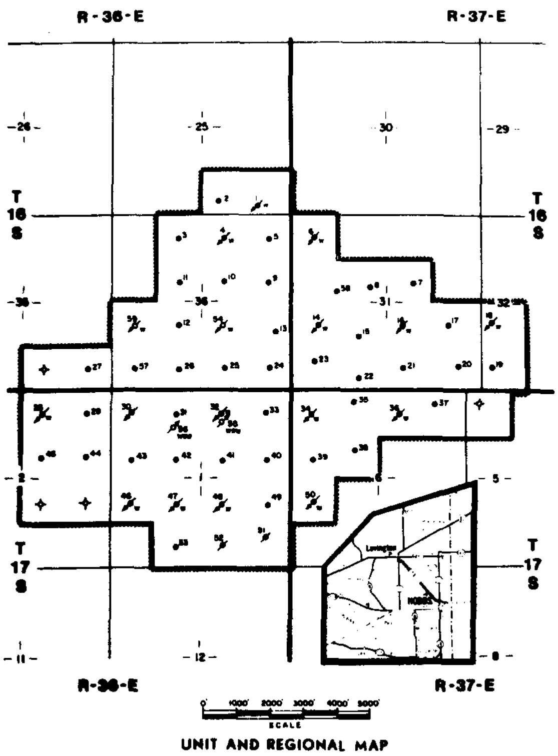
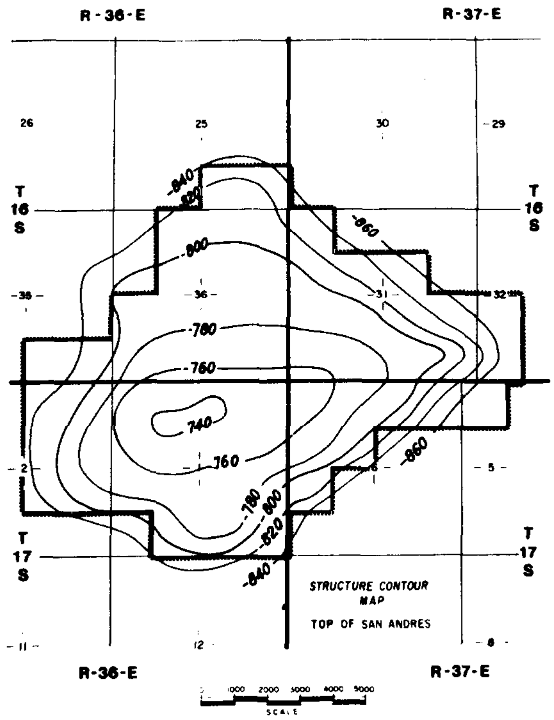
INTRODUCTION

The Lovington San Andres Pool is located, as shown in Fig. 1, in central Lea County, New Mexico, approximately 10 miles northwest of the city of Hobbs. The 2400-acre pool was discovered by the completion of Skelly Oil Co.'s State "N" Well No. 1, which was drilled in January 1939. Rapid development in the early life of the pool resulted in 57 productive wells being completed on 40-acre spacing. In 1952, discovery of oil production in the deeper Paddock and Abo formations resulted in two, and many times three, wells being located on the same 40-acre tract.

The Lovington San Andres Pool was unitized in late 1962 for the purpose of initiating a field-wide waterflood. Skelly Oil Company, as unit operator, began water injection early the following year. This paper is a review of the operation and performance of the 8-year-old waterflood project.



UNIT AND REGIONAL MAP
LOVINGTON SAN ANDRES UNIT
Lea County, New Mexico
FIGURE 1



LOVINGTON SAN ANDRES UNIT
Lea County, New Mexico
FIGURE 2

GEOLOGY AND RESERVOIR DESCRIPTION

The Lovington San Andres Pool is located along the Vacuum Trend on the northwest flank of the San Simon Channel. The reservoir is described as a dolomite of Permian Age, and is predominantly composed of hard, dense crystalline dolomite with intermittent streaks of gray shale, anhydrite and sand. The structure, as shown in Fig. 2, has a depth of approximately 4600 feet and is a domal-type anticline trending northeast to southwest. Productive limits on the flanks of the structure are attributed to lack of permeability and porosity development, as well as to the existence of bottom or edge water. Available data indicate that several separate pay zones of a fairly continuous nature exist throughout the 400 to 500 feet of gross section. Net pay has been estimated to average 38 feet in thickness. A typical log from the pool is shown in Fig. 3.

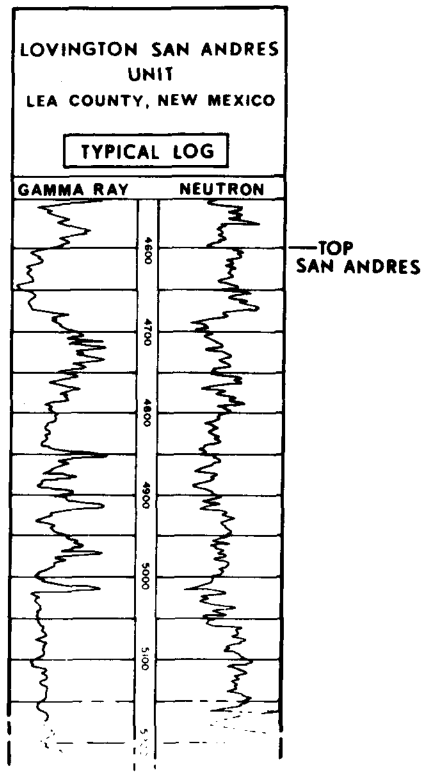


FIGURE 3

Core analysis data available from only one well in the pool shows the weighted average porosity and permeability to be 8.6 per cent and 6.4 md, respectively. Volumetric calculations for an oil-in-place of 37.6 million barrels used an average porosity determined from well logs of 10 per cent and an estimated connate water saturation of 30 per cent. Material balance calculations of oil-in-place when compared to the volumetric calculations support the higher porosity value.

The San Andres formation produces a greenish-black crude of approximately 36° API gravity. The reservoir was initially found to be in an undersaturated state when initial bottomhole pressure exceeded the saturation pressure by about 460 psi. A summary of pertinent data, including initial reservoir conditions and general information, is shown in Table 1. The reservoir was produced to a nearly depleted stage primarily by a solution-gas drive mechanism. No evidence of extensive water encroachment or gas-cap drive has been indicated, although some water was produced during primary depletion.

PRIMARY HISTORY

Primary performance history for the Lovington San Andres Pool is shown in Fig. 4. Within one year from its discovery, the pool's monthly oil production had reached 35,000 BOPM, and ultimately a rate of over 50,000 BOPM was reached during the period from 1943 to 1948. A four per cent per-year decline in the oil-producing rate was observed prior to secondary recovery operations. Over 40 wells were drilled in the pool on 40-acre spacing during the period 1939 through 1941. All wells, with the exception of two late completions that were cased through and perforated, were completed through open-hole section over a depth range of 4525 feet to 5100 feet. Casing of 5½ in. or 7-in. diameter was set near the top of the San Andres formation. Well stimulation by 2000 gallons acid treatment was generally practiced throughout the field. Some wells have received as many as six such treatments during their lifetime. Daily oil production at the start of water injection averaged six BOPD per well with an average water cut of 35 per cent.

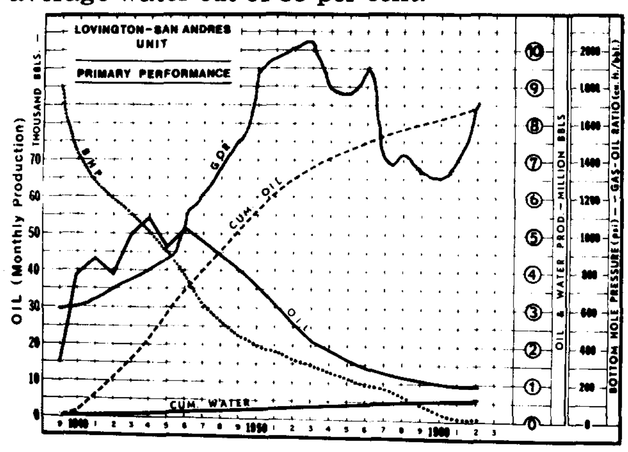


FIGURE 4

The estimated ultimate primary oil recovery for the San Andres Pool was 9.0 million barrels, which represents a recovery of 99 STB per acre-foot of net pay. At the start of injection operations, cumulative oil production was 8.46 million barrels, which indicates that

TABLE 1

LOVINGTON SAN ANDRES UNIT

Basic Data

Type Drive — Solution Gas
Productive Area — 2389.8 acres

Formation —
San Andres, dolomite (Permian Age)
Avg. thickness = 38′

Rock Properties —
Avg. Wtd. porosity = 8.6% (Core Analysis); 10% (logs)
Permeability = 6.4 md
Connate water saturation = 30% (Est.)

Reservoir Fluid Properties	
Original Bottomhole pressure	= 1795 psia
Bottomhole temperature	= 114° F
Saturation pressure	= 1336 psia
Initial solution gas-oil ratio	= 510 cu. ft./bbl.
Initial formation volume factor	= 1.296 res. bbl/STB
Performance Data —	
Stock tank oil initially in place	= 37,600,000 bbl.
Estimated ultimate primary production	= 8,994,245 STB
	= 99.6 STB/Ac-ft.
	= 23.8% STOIIP
Cumulative production @ 4-1-63	= 8,456,370 STB
	= 94% Est. ultimate primary
Cumulative production @ 1-1-71	= 10,664,000 STB

94 per cent of the ultimate primary had been recovered. Figure 5 shows the areal variation of cumulative oil production at the start of secondary recovery.

During primary depletion, wells on the east and south flanks of the pool produced some water. A small degree of water influx was probably associated with the water production. However, its influence was minor, and it was easily excluded by plugging back during recompletion.

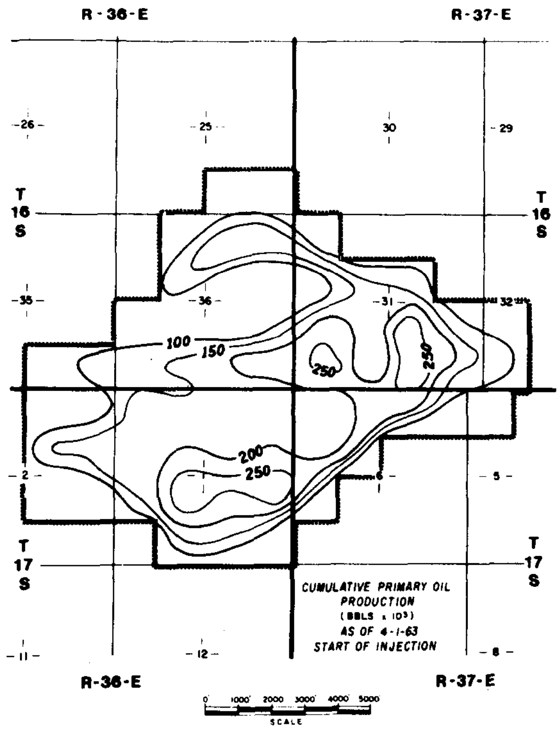
UNITIZATION

The Lovington San Andres Unit became effective August 1, 1962. Prior to unitization, an engineering subcommittee completed a secondary recovery study recommending the formation of a unit for waterflooding. Working-interest owners agreed on a two-phase participation formula covering production of remaining primary and anticipated secondary reserves. Primary participation was based on 70 per cent of current production, 20 per cent on remaining primary and 10 per cent on adjusted ultimate primary. Secondary participation was based solely on adjusted ultimate primary production. Adjustment of ultimate primary production was necessary so that operators could receive credit on undeveloped tracts. Ultimate reserves were assigned to these seven undeveloped tracts on the basis of performance of offsetting wells.

Permission to conduct waterflood operations in the Lovington San Andres Unit was granted by the New Mexico Oil Conservation Commission under the Statewide Rule 701 (E). Under this rule, the project area included all wells that are directly or diagonally offset to injection wells. The basic unit allowable was set for the total project at 42 BOPD per well, subject to market demand, with no restriction placed on individual well production.

WATERFLOOD HISTORY

Water injection was started in the Lovington San Andres Pool in March 1963. Initially, 14



LOVINGTON SAN ANDRES UNIT

Lea County, New Mexico

FIGURE 5

wells were placed on injection to establish the inverted nine-spot pattern as shown in Fig. 1. Unit Wells Nos. 1 and 47 were later converted to injectors, Unit Well No. 59 was drilled in June 1965 as an injector. Cumulative oil production at the start of injection was 8,456,370 barrels, which represents a range of 51,000 to 293,000 barrels from individual wells. Average producing rate and water cut for the unit at this time was six BOPD per well and 35 per cent, respectively.

The water supply for the project is the Ogalalla formation, which is found in the unit area at an approximate depth of 100 feet. Two supply wells (Unit Well Nos. 55 and 56) located near the injection plant provided the initial injection rates of 6000 BWPD. Both wells on completion were gravel packed and cased with 9⅝ in. casing. Lift equipment on each well consists of a line-shaft turbine pump powered by an 8½ in. × 10-in. Ajax engine. Laboratory tests showed only a mild incompatibility between the fresh Ogalalla and saline San Andres waters. The oxygen content of the fresh water suggested that a closed-supply system would be prudent; consequently, such a system was installed.

A water injection plant consisting of three Ajax Triplex pumps driven by Ajax DP-115 gas engines was installed in early 1963. This equipment, capable of delivering 9000 BWPD at 1500 psi, was enclosed in a metal building for weather protection and to facilitate proper housekeeping. Pump design included aluminum-bronze fluid ends and ceramic plungers to facilitate handling of corrosive fluids, which were anticipated in later stages of the flood. Each pump was served by a 500-barrel supply tank that was elevated to assure proper suction. All inlet piping was internally coated with plastic, and outlet piping was internally coated with cement. As pump loads increased, problems developed during the summer months from overheating of the prime movers. Three water air conditioning units were installed, effectively eliminating this heating problem, and a duct system was added to improve circulation of cooling air within the building.

A multilateral distribution system was installed to deliver pressured water from the centralized plant to the individual injection wells. Each lateral consisted of welded, cement-lined steel pipe that was externally coated and buried. Each lateral served from four to seven injection wells, depending on surface topography. Corrosion problems with this system have been virtually nil. Sacrificial anodes were installed on the system to provide a measure of "hot spot" protection to compensate for any holidays that might develop in the external coating. In 1968, after installation of a twin system for the Lovington Paddock Unit, output of the anodes was resurveyed and additional anodes were installed to restore the level of protection to serve both systems. Success of these corrosion-mitigation measures is attributed primarily to three factors: (1) successful isolation of the system from the injection wells and other related structures, (2) rigorous specifications for internal and external coatings, and (3) diligent inspection by field and engineering personnel of coating application and installation operations.

Each injection well was equipped with an injection header assembly that was internally coated and consisted of a master valve, a check valve, an individual meter for injected volumes, a strainer, and a throttle valve or choke assembly for injection volume control. Isolation from the distribution system was achieved by use of a fiberglass nipple. For operations during the winter months, each header was enclosed in a freeze box. Injection tubing was internally coated for corrosion control. Tubing was set using a tension-type packer approximately 50 feet above the casing seat or uppermost perforations. Each annulus was loaded with a corrosion inhibited fluid.

Injection of produced water into one lateral serving seven wells began in 1966. Because the oxygen-saturated supply water was incompatible with the sour produced water, separate injection systems were maintained for these two waters. All produced water has been recycled since that time. From the start of injection in 1963, the fresh supply of water exhibited tendencies to support the growth of slime-producing algae. This growth was satisfactorily controlled by batch treatment with biocide at the injection plant, although experimental continuous treatment was unsuccessful. In mid-1969, water-handling procedures were revised, and treatment of supply water with sulphur dioxide for oxygen scavenging was started. This eliminated the necessity for separate facilities.

When the Lovington San Andres Unit became effective, production facilities consisted of individual tank batteries located on the individual tracts. After response was achieved, production facilities were consolidated into a central tank battery, located adjacent to the injection plant. Four satellite test stations were used to improve operating efficiency and permit accumulation of adequate well-test data.

Central battery equipment consisting of a free-water knockout vessel, emulsion treater, storage tanks and LACT unit was installed. A coalescer vessel was installed to condition produced water for recycling and a 5000-barrel open-topped epoxy-lined tank was added to provide emergency surface storage for produced water in the event of injection pump shutdown. This installation was necessary because the city of Lovington's water supply is in the immediate area of the unit.

Four satellite test stations were installed, each serving the group of wells in its respective area. Individual flowlines were provided for each producing well to its respective satellite. Trunklines from each satellite station transported all produced fluid, including gas, to the central battery. Each satellite test station consisted of a manifold system and a test treater with separate meters for gas, oil and water volumes. No tankage was provided at the satellite test stations; only production from the well on test was handled by the test facilities. All other wells were diverted by the trunkline directly to the central battery. Produced fluids from the well on test were introduced into the trunkline downstream of metering facilities. Test facilities were designed for manual testing, but are easily adapted to automation.

At the time of unitization, producing wells were equipped with small-volume beam pumping units (predominantly API 114 or smaller) and gas engines. This installed equipment was used until well response required larger lift equipment. Residue gas from the gas plant in the field was available for fuel; this coupled with the relatively large volumes of fluid to be handled by beam pumping units made use of gas engines economical for this application. Larger lift equipment installed was predominately 320 BG units, Ajax 8½ in. × 11-in engines.

WATERFLOOD PERFORMANCE

Waterflood performance for the Lovington San Andres Unit is illustrated in Fig. 6. Oil response was observed during March 1964, 12 months after the start of injection. The oil-producing rate increased from 8000 to 30,000 BOPM eight months after the response was noted. Production peaked slightly below 30,000 BOPM for nearly three years before starting on a 7 per cent-per-year decline for the past four years. Water injection rates essentially remained constant at 180,000 BWPM for the first six years of the project's life. During the past two years, injected volumes increased slightly, to 190,000 BWPM. This is attributed to an increase in plant engine speed, well stimulation and conversion of Unit Well No. 47 to injection status.

The increase in water production noted in the early stage of injection raised the water cut from 35 per cent to a level of 55 per cent. The increase in oil rate due to response was associated with increased volumes of water which, after a slight drop, have continued to increase the water cut to its present value of 80 per cent. The more significant volumes of water that occurred at the time of response have been from wells along the extreme eastern and southern flanks of the pool. These wells produced some water during primary deple-

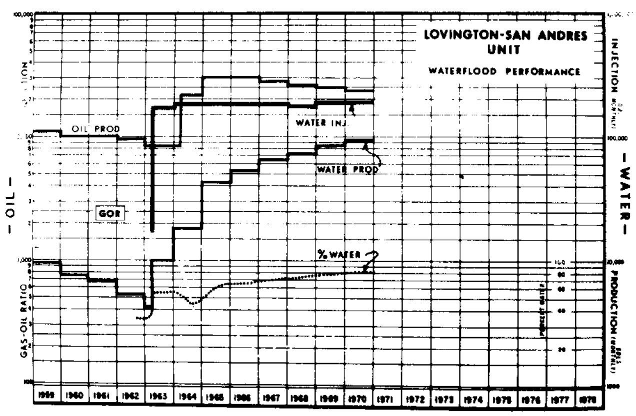


FIGURE 6

tion; consequently, the water cut increase at response is attributed to injection in zones partially flooded by water encroachment under primary depletion.

A review of performance 18 months after the start of injection showed response primarily in the south half of the unit. It was found that response in the northern area had not been achieved, due to the limited capacity of existing injection wells. In mid-1965, to increase injection, Unit Well No. 1 was converted to injection, and Unit Well No. 59 was drilled and completed for injection service.

Performance of the project from late 1965 to the present shows an increase in water cut to 80 per cent and a decline in oil production to 23,000 BOPM. Cumulative oil produced from the start of water injection to January 1, 1971, has been approximately 2.2 million barrels. Total water injected to this date has been 17.1 million barrels. Net water injection, accounting for the 5.4 million barrels of water production, has been 11.7 million barrels.

Figure 7 is an incremental isocumulative recovery map relating production since the start of water injection. As may be noted, secondary oil recovery has been greatest along the southern and eastern flanks of the pool. The structurally deeper wells in these areas (adjacent to the unit boundary) exhibit lower secondary production, supporting the concept of some water influx during primary depletion. The abnormally low recovery in the southwestern part of the unit is from Unit Well No. 43 and is attributed to partial flood-out under water influx. A general trend reflecting the ratio of secondary recovery to primary recovery is shown in the comparison of

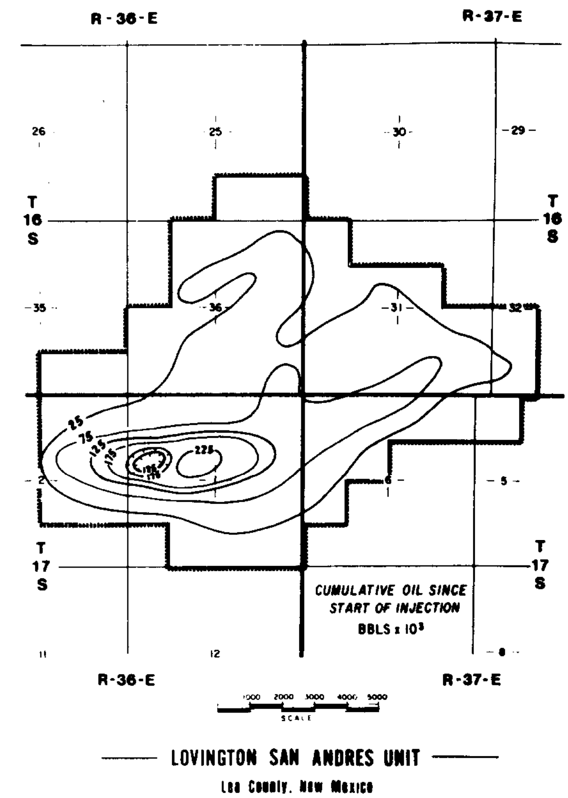
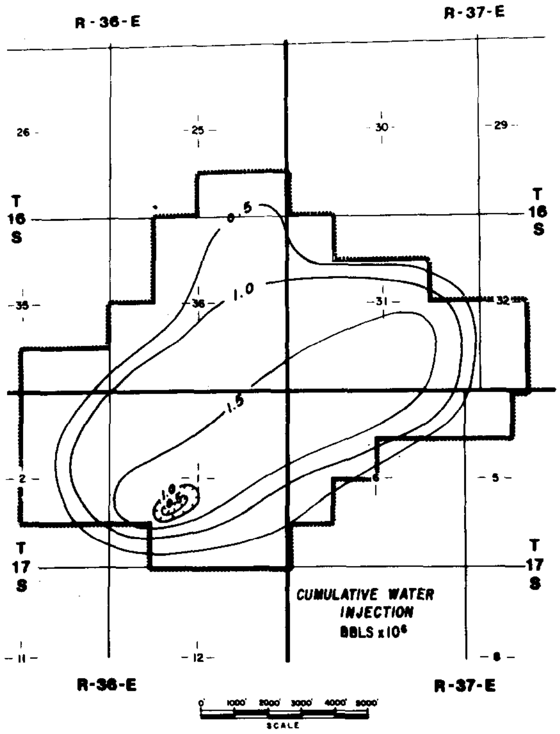


FIGURE 7

Figs. 5 and 7. Secondary oil recovery to date for the unit has been approximately 25 per cent of the estimated ultimate primary recovery. In the area of greatest secondary oil recovery, inside the 75,000-barrel contour, secondary recovery is estimated to range from 30 to 130 per cent of ultimate primary recovery.

Response in the northern half of the unit has been restricted due to poorer reservoir conditions. Primary oil recovery reflects these conditions, as do the lower volumes of cumulative water injection indicated on the isocumulative injection map shown as Fig. 8. Injection of over 1.5 million barrels per well is illustrated in the area of better recovery, with lesser volumes having been injected in wells to the north. As mentioned previously, Unit Well No. 47 was converted to injection in 1969 and is reflected as the abnormally low-volume area noted in the figure.

Analysis of producing-well performance in late 1970 showed that over 50 per cent of the monthly oil production was from seven (18 per cent) of the wells. Also, over 50 per cent of the monthly water production was from eight (21 per cent) of the wells. Nearly 40 per



LOVINGTON SAN ANDRES UNIT

Lea County, New Mexico

FIGURE 8

cent of the producing wells showed rates greater than the per-well unit average rate for both oil and water production. Fifteen wells were found to produce above the average oil rate, and 13 wells were found to produce above the average water rate. Two of the high-volume water producers are direct offsets to injection wells and account for 22 per cent of the total water production.

In the last half of 1970 ten of the injection wells were operating at maximum line pressure. Eight of these wells are located in the northern half and along the western flank of the unit. The remaining seven wells were operating at below-line-pressure to achieve the desired injection rates for their individual patterns. These seven particular wells are in the area previously mentioned as that which has contributed most to the secondary recovery. Of the 17 injectors in the unit, ten (59 per cent) are taking volumes in excess of the per-well average.

It is anticipated that water-cut performance for the unit will remain near the 80-90 per cent range. Well behavior is periodically checked during an analysis of each pattern in the unit. From the analyses, decisions are reached regarding such items as balancing rates between patterns, well treatments, pattern flood efficiency, etc. Future operation of the unit will show continued response, with below-unit-average water cuts in the northern area increasing with time, and will also reveal that efforts will be required to achieve ultimate pattern sweepout in the southern and eastern areas.

PROBLEMS AND SOLUTIONS

Assessment of floodability of the Lovington San Andres reservoir was unsupported due to the meager experience that existed in the early 1960s in flooding the San Andres formation. Efforts to firmly establish continuity of zones by log evaluation were unrewarding because of log quality and the erratic nature of porous intervals in carbonate rocks. Analyses of well performance and injectivity profiles, available under secondary operations, have aided subsequent evaluations of project behavior.

Initially, concern for oriented permeability in carbonate rocks led to adoption of the inverted nine-spot pattern for the unit. The chosen pattern has proved effective and flexible, although permeability orientation has not been an apparent problem. Performance around injection Well No. 47 indicated by early water breakthrough that channeling might be a problem. Dye was placed in the injector, with the expectation that it would be rapidly recovered in the offset producer. The dye was never detected; consequently, it was concluded that it dispersed in a water zone that did not directly communicate with a producer. The inverted nine-spot pattern has provided the necessary flexibility to increase injection capacity in certain areas by modifications to the more familiar five-spot pattern.

The shutting down of injection engines due to overheating in the summer months was eliminated by the installation of down-draft evaporative coolers. The air was directed so that the radiator fan would pull cool air across the breathers. Air circulating tubes were installed from the radiator exhaust duct down into the engine exhaust trench. This allowed the very hot air in the exhaust manifold trench to be removed to a point outside the building. The minor expenditure for the system has resulted in much less engine load, which will extend engine life and has reduced maintenance costs.

It has been possible to continue normal plant operation even on days when outdoor temperatures have exceeded 100 degrees.

Injection well performance has been indicative of some minor problems encountered in the life of the project. Prediction of rates at different pressures, wellbore plugging and slippage in water meters are examples of problems that have been resolved using an analysis technique reported by H. N. Hall.[1] The application of this technique is adequately discussed in a more recent article; consequently, it need only be said that well problems can be analyzed using the coordinate plot of "summation of wellhead pressures multiplied by time versus cumulative water volume injected. (WHP × time vs. cum. water injection)".[2] The plotted data develops into a straight line that has been used to predict rates at different pressures; deviations from an established straight line have indicated plugging due to buildup of algae in the wellbore and slippage in water meters, which produced inaccurate measurements.

CONCLUSIONS

1. The main producing mechanism during primary depletion was solution gas drive with a minor degree of water influx. The water influx has resulted in a higher primary recovery and a lower secondary recovery than otherwise might have been expected.
2. Secondary oil recovery for the unit to date has been 25 per cent of primary recovery, with areas within the project indicating secondary recovery ranging from 30 to 130 per cent of primary recovery.
3. Secondary oil recovery has been greatest along the southern and eastern flanks of the reservoir.
4. Reservoir conditions in the northern area of the unit are poor, and this condition is reflected in both primary and secondary recoveries.
5. The inverted nine-spot pattern has been effective and flexible in project operation.

REFERENCES

1. Hall, H. N.: How to Analyze Waterflood Injection Well Performance, *World Oil,* October 1963, pp. 128-130.
2. DeMarco, M.: Simplified Method Pinpoints Injection Well Problems, *World Oil,* April 1969, pp. 92-100.

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