MISCIBLE DISPLACEMENT BY HIGH-PRESSURE GAS AT BLOCK 31*

JAY H. HARDY and NELSON ROBERTSON
Atlantic Richfield Company

The world's first large-scale miscible displacement project by high-pressure gas injection has produced 130,000,000 bbl, almost double the original estimated primary recovery of 69,000,000 bbl, at the University Block 31 field in Crane County, Tex. Early injection-production history is shown on Fig. 1.

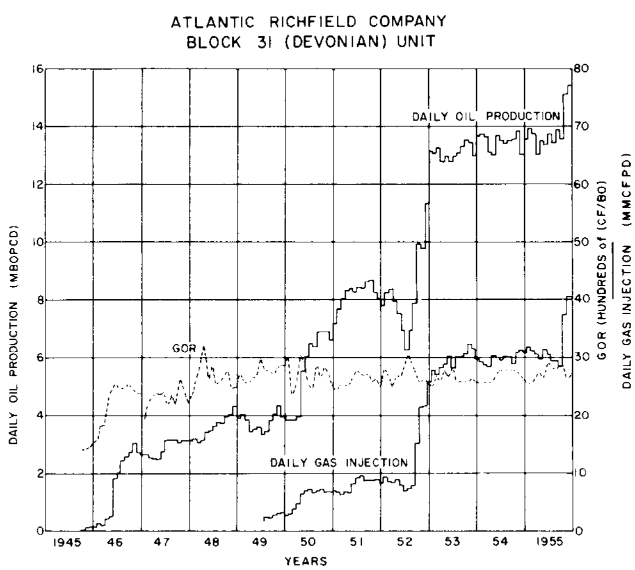

FIG. 1—INJECTION AND PRODUCTION HISTORY FOR BLOCK 31 FIELD, CRANE COUNTY, TEX., 1945-1955.

The field-wide project began in 1952, and will keep the unit on stream well into the future, with ultimate recovery efficiency estimated at 60%. Infill drilling has helped boost daily production to 16,000 bbl, highest producing rate since gas injection began in 1949.

---

* This paper is reprinted from Petroleum Engineer magazine with their permission.

Atlantic Richfield (formerly The Atlantic Refining Co.) discovered Block 31 in 1945. Operators agreed to reinject produced gas into the Devonian reservoir in 1949 for partial pressure maintenance. The field was unitized in August, 1952, with Atlantic Richfield as the unit operator. Others include Phillips Petroleum Co., Champlin Petroleum Co., and Continental Oil Co. Extensive research indicated that oil recovery could be improved substantially by miscible displacement through high-pressure gas injection.[1,2] Waterflooding was impractical because of the low permeability of the Devonian formation.

The reservoir contains five producing horizons, of which the Devonian at 8500 ft is dominant. The miscible project, which began in 1952, includes 86 oil producing wells and 24 gas injection wells. Eighty-acre spacing was used to develop the 7840-acre unit. Devonian gas injection is based on a 320-acre nine-spot pattern.

The Devonian formation is a crystalline limestone, interspersed with chert. Average porosity is 15% and average permeability is 1 md. Gross thickness is 1000 ft. There are three reservoirs in the Devonian column: Upper, Middle, and Lower. The major reservoir is the Middle. The trapping mechanism is a northeast to southwest trending anticline with the south end cut by a normal fault. Flanks of the anticline are delineated by a water-oil contact.

HIGH-PRESSURE GAS MISCIBILITY

In the Block 31 (Devonian) reservoir, lean hydrocarbon gas is injected at high pressure. The leading edge of gas strips the LPG through gasoline type intermediate hydrocarbon components from the oil. This front becomes enriched, and some of the gas dissolves in the oil, causing it to swell. Swelling in itself improves recovery, but miscibility is the ultimate goal, and it occurs as gas contacting continues and the two phases merge into one phase. The miscible front literally washes all of the contacted oil from the formation. Displacement can be as high as 95% to 100%. This is offset, however, by a loss in sweep efficiency from an unfavorable 10:1 gas-to-oil mobility ratio. Stratification and fractures also offset displacement.

An important requirement for miscibility to occur at modest pressures is that the crude contain sufficient intermediates. Because the lean gas strips these intermediates, the C_2-C_6 total components should be greater than 30 mol %.[3] Reservoir oil at Block 31 contains 36% intermediates. The crude also must be sufficiently undersaturated with respect to the pressure at the gas-oil front.[4] Density of the reservoir oil must be low as reflected in stock tank gravities of 40° API and higher.[5] Reservoir temperature is not critical. Block 31 crude has a saturation pressure of 2764 psi and is 48° API gravity. The bottomhole temperature is 140° F.

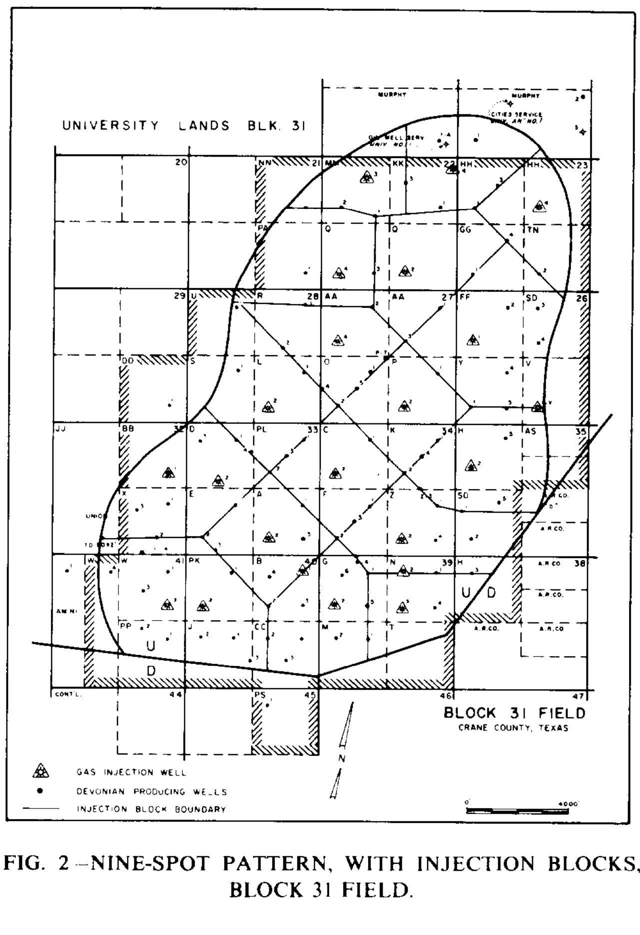

FIG. 2—NINE-SPOT PATTERN, WITH INJECTION BLOCKS, BLOCK 31 FIELD.

Miscibility requires high injection pressures and volumes, which mean large horsepower. Block 31 has 53,500 bhp developed by 29 compressors which inject 134,000,000 cfd of gas to maintain 3500 psi pressure at the miscible bank. To accomplish this, compressors discharge at 4200 psi. In some less permeable zones, this pressure is boosted to 5000 psi. Formation depths (8500 ft) make the Devonian ideally suited for high pressure injection without fracturing.

Over the years the Devonian reservoir has been carefully managed to maintain miscibility. It is divided into injection blocks (Fig. 2), and over-or under-injection into each block has been controlled. When pressure in an injection block drops below miscibility, voidage is reduced or injection increased. Miscibility is regained by repressuring. This is possible because the injected gas manufactures its own miscibility by stripping the intermediate components from the reservoir crude. Regaining miscibility, however, is done at a higher miscible pressure where the reservoir has been immiscibly swept. This is because, at the lower pressure, some intermediate hydrocarbons are stripped from the oil into the gas even though the displacement is not miscible. Gas breakthrough is undesirable since gas may cycle through the swept zone to prevent the pressure from increasing.

FLUE GAS GENERATION

Since miscibility in a high-pressure gas displacement process is created in situ by vaporizing intermediate hydrocarbons into the displacing gas front, lean hydrocarbon gas or, also, flue gas can be enriched with these intermediates to the point of miscibility. In Block 31, the miscibility pressure for flue gas was practically identical to the miscibility pressure for hydrocarbon injection gas. The decision to use flue gas was made by 1966.

At the time full pressure maintenance got underway in 1952, the unit was purchasing 30,000,000 to 40,000,000 cfd of make-up gas to replace voidage. Economic studies justified a flue gas plant to manufacture make-up gas, and savings from discontinued purchase of make-up natural gas, plus sales of 20,000,000 to 30,000,000 cfd of produced gas, paid out the flue gas facility. The plant also provided a reliable supply of displacement gas.

The flue gas plant for hydrocarbon recovery is the world's largest.[6] It is designed to produce 54,000,000 cfd of flue gas, which is about 87 mol % nitrogen, 12mol % carbon dioxide and 1% carbon monoxide. Fuel for the plant is a residue gas from the Block 31 gasoline plant. One cu ft of residue gas makes 9 to 11 cu ft of flue gas. A sulphur treating system sweetens the gas prior to burning, which helps reduce fouling and corrosion problems.

During burning, flame temperatures are controlled by recirculating stack gas around the periphery of the burner. This prevents highly corrosive oxides of nitrogen from forming at elevated burner temperatures. This technique enables the plant to make quality flue gas without using a catalyst to convert the nitrogen and oxygen compounds. The flue gas is collected in a 54-in. duct and scrubbed in a quench tower. As the gas cools, combustion water condenses and is collected for boiler feed to make steam.

The combustion section consists of four 100,000 lb/hr steam packaged boilers. Steam at 600 psi is generated in the boilers as an adjunct to the flue gas. The steam drives a 23,500 bhp steam turbine connected to centrifugal compressors which boost the flue gas from a few inches of water to 1200 psi in five stages.

The first compressor (two stages) is directly coupled to the steam turbine which rotates at 4300-4600 rpm. Two compressors make up the last three stages. They operate at 11,000 rpm. A 2.547 ratio speed increaser connects the first compressor with the other. The compressed flue gas, which heats to 300 to 320°F, is cooled by atmospheric coolers. Ammonia (NH_4OH) is injected to neutralize acid gases to prevent formation of carbonic and nitric acid. After compression to 1200 psi, the flue gas is dehydrated by refrigeration and glycol injection. Three two-stage reciprocating compressors boost the gas from 1200 psi to 4200 psi discharge pressure.

A fifth power boiler makes up any steam supply deficiencies, and steam from the five boilers powers the allied rotating machinery to use the heat left over from flue gas generation.

Injection well plugging did occur after flue gas injection start-up due to compressor lubricant and iron sulphide formed by the mixing of flue gas and sour hydrocarbon gas in the same injection well. A special lubricating oil eliminated the problem. Mixing of flue and sour hydrocarbon gas also was limited. As an additional precaution, cartridge-type filters were installed at the compressor discharge and wellhead.

PRODUCTION PROBLEMS

Injected flue gas has broken through into oil producing wells. Because it contains carbon dioxide and nitrogen, flue gas lowers the Btu quality for the produced hydrocarbon gas, some of which is used for fuel. Fuel gas contamination from the low Btu gas appears to be a long-range problem and various solutions are under study.

Because of gas breakthrough, there are four gathering systems operating at different pressures: 40 psi, 175 psi, 500 psi, and 1200 psi. Wells are switched from system to system, which permits continued production of increasing GOR wells with a minimum amount of compression. There is a limit, however, as to how much gas a well can produce economically. When the GOR gets too high, the well is converted to gas injection service.

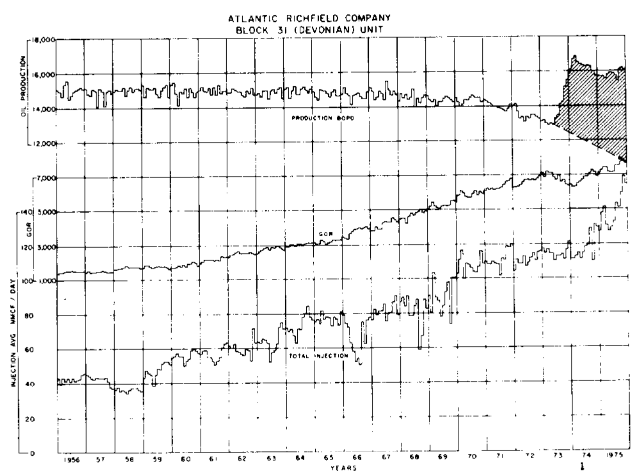

FIG. 3—BLOCK 31 FIELD INJECTION-PRODUCTION HISTORY, 1955-1975.

NEW LIFE FOR AN OLD FIELD

As production rates continued to decline in 1972 (Fig. 3), drilling additional producing wells was considered. A two-dimensional, three-phase math model showed areas of low gas saturation between the side and corner wells of the nine-spot pattern. An oil bubble and gas bubble map (Fig. 4) based on net gas injection confirmed the model. After drilling several edge wells in areas of low saturation, an oil

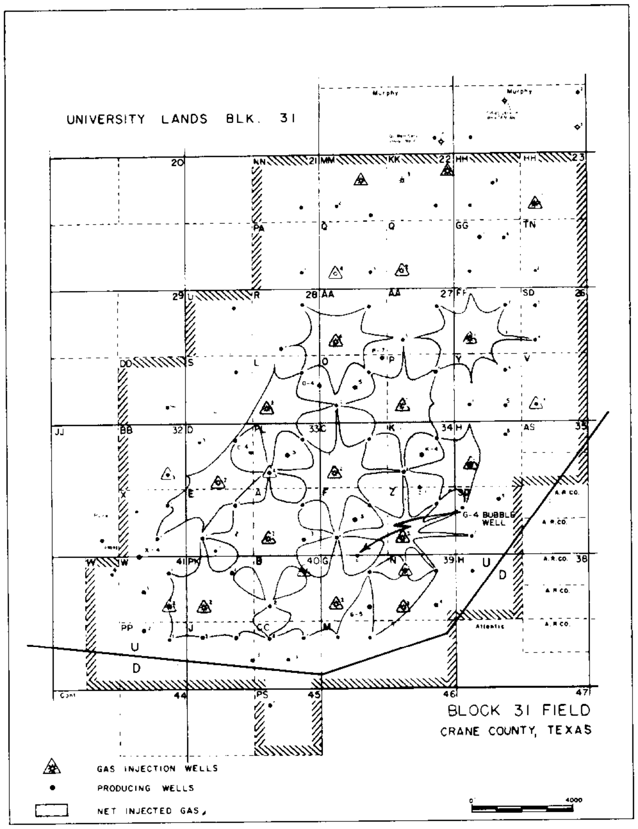

FIG. 4—VOLUMETRIC SWEEP PATTERNS BASED ON NET GAS INJECTION.

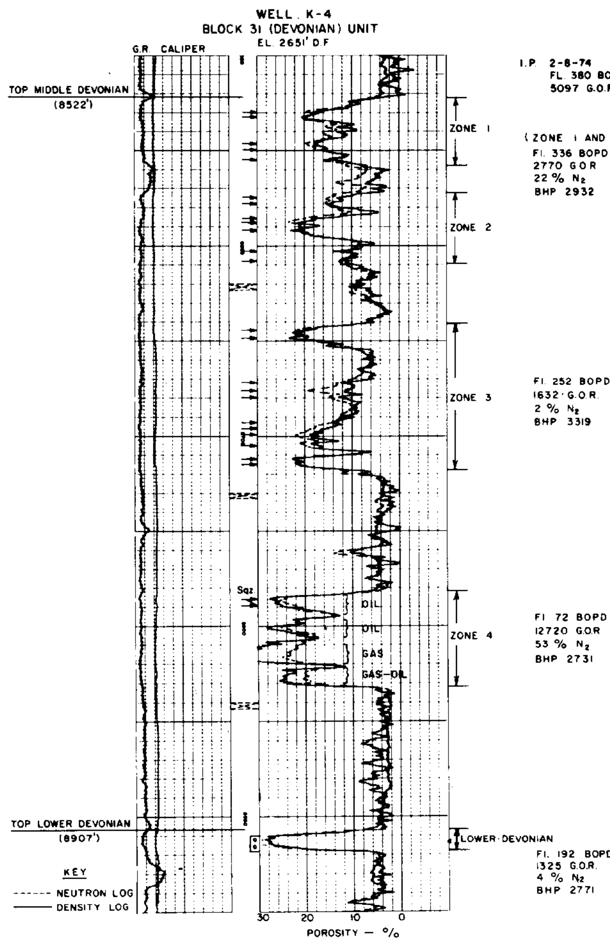

FIG. 5—GAS EFFECT SHOWS UP ON LOG OF WELL K-4.

bubble well, G-4, was drilled. It came in with a low GOR of 3482 (field average GOR was 6800) and the well flowed 456 BPD. This successful well initiated 12 infill wells. Production increased from 13,000 bbl to 17,000 bbl in 10 months. Gas production was held down because the new infill wells had a GOR of 2254, while the field was averaging 6800:1. Had the infill wells produced at a higher GOR, the plant would not have been able to handle the gas and the voidage could not have been replaced.

Well completion design held the GOR of infill at a minimum. An important tool in the procedure was the compensated density, neutron logging package. Although the model indicated areas of low saturation, there was a possibility of drilling into gassed-out zones. The logging package located these zones, and wells were not completed in them. Several zones were tested, however, and they had GOR's greater than 12,000:1. This was unacceptable. Gas effect can be seen on the log presentation (Fig. 5) and/or can be calculated by cross-plotting the density and neutron porosities. The neutron tool indicates low porosity in a gas zone and the density tool high porosity. An anomaly between the two curves, known as gas effect, is created.

Since the Middle Devonian had four pay zones, each was isolated and treated using a retrievable bridge plug and test packer. The gassed-out zone was left behind the casing. Each zone was perforated through tubing, using limited entry, acidized, and balled out using ball sealers. If, after testing, a zone had a 10,000 GOR or greater it was squeezed and the completion procedure continued higher in the wellbore.

Future plans are to drill on 40-acre spacing and go to an 80-acre five-spot injection pattern. New producing wells would be drilled and a number of existing producers would be converted to injection wells. Ultimately, there would be 65 injection wells instead of the current 24. Closer well spacing would allow sustained miscible conditions with a lower well injection rate. Sweep efficiency would be improved by allowing the miscible front to contact more oil. In addition, the five-spot pattern would recover more reserves from those intervals that have experienced gas breakthrough. Instead of cycling the gas from existing injectors to producers, the cycled zones would be repressured. Injected gas would be forced into unswept areas and sweep efficiency of the breakthrough zones would be improved.

Currently, a pilot 80-acre five-spot is being installed in the southern part of the unit. A four component model study, which simulates miscible conditions, is being conducted in the center of the unit. This will enable the prediction of additional recovery attributable to the 80-acre five-spot pattern as well as the economics involved.

REFERENCES

1. Whorton, L.P., and Kieschnick, W.F.,Jr.: A Preliminary Report on Oil Recovery by High Pressure Gas Injection. API Paper 851-24-D, Okla. City, Okla, Mar. 1950.
2. Whorton, L. P., and Brownscombe, E. R. : U. S. Patents 2,724,437 and 2,724,438 (Nov. 22, 1955).
3. Koch, H. A., Jr.: *World Oil*, Oct. 1956, Vol. 143, pp. 260-264.
4. Slobod, R.L., and Koch, H.A.Jr.: Which to Use- I Type or M Type - For High Pressure Gas Injection. *Oil and Gas Jour.*, Apr. 6, 1953, p. 84.
5. Frick, T.C. : Petroleum Production Handbook, Vol. II, Reservoir Engineering, McGraw-Hill Book Co., 1962, Chapter 40, pp. 28-30.
6. Caraway, G. E., Jr., and Lowrey, L. L. : Flue Gas Generation Problems, Solutions and Cost-Block 31 Field. Southwestern Petroleum Short Course, Texas Tech University, Lubbock, Tex. Apr. 1975.