

# Pressure Maintenance by Waterflooding North Virden Scallion Field, Manitoba

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## ABSTRACT

The North Virden Scallion field is located on the north-east flank of the Williston Basin and produces from the Virden and Scallion members of the Lodgepole formation of Mississippian age. The reservoir was highly undersaturated initially. The sources of energy for primary production were combinations of oil expansion, partial edge-water drive and limited bottom-water drive. Laboratory flooding tests and engineering calculations indicated that waterflooding could more than double the anticipated primary recovery and significantly increase the rapidly declining production rates. It was estimated that the ultimate primary recovery of 25,000,000 barrels could be increased to 55,000,000 barrels.

After five years of planning and negotiating, a portion of the field was unitized and a nine-spot waterflood was installed. Water injection began in December, 1962. Results to date have been encouraging. Production has increased from a pre-flood rate of 2,900 BOPD to 4,750 BOPD. Additional oil recovery due to waterflooding is estimated to be more than 500,000 barrels to year-end 1964. To assist in predicting and controlling the advance of the flood fronts, injection profiles have been run on the injection wells and a digital computer model to simulate the project is currently being constructed.

## INTRODUCTION

THE North Virden Scallion field is located in southwest Manitoba, 30 miles east of the Saskatchewan border and due north of the town of Virden. This places the field approximately midway between Regina and Winnipeg. Production is obtained from the Virden and Scallion members of the Lodgepole formation of Mississippian age at a depth of 2,000 feet.

The field was discovered in December, 1953, by The California Standard Company with the drilling of Calstan Scallion 3-11-11-26 W.P.M. Development followed rapidly, and by 1961 more than 300 wells had been drilled, of which 274 were capable of production. All wells were drilled on 40-acre spacing and placed on pump soon after completion.

In early 1957, the field's production rate and pressure were declining rapidly and the need for pressure maintenance had become obvious. Engineering and laboratory studies conducted that year showed that waterflooding was the only economical method of secondary recovery.

After an attempt to initiate a pilot waterflood failed in 1958, negotiations to unitize the field began. On August 1, 1962, the North Virden Scallion Unit No. 1 became effective. The Unit contained 217 wells completed in the Lodgepole formation. (See Figure 1). The remaining wells, located on the down-dip southwest flank, were not included because they were

being effectively depleted by edge-water drive. Injectivity calculations indicated that an inverted nine-spot pattern would provide sufficient injectivity to more than maintain pressure. Pattern adjustments had to be made because of window tracts which were not in the Unit. The injection systems were installed in two phases. Phase one, installed in the fall of 1962, consists of thirteen wells injecting produced Mississippian water into the central and southern portion of the Unit. It offsets the natural water-drive area. Phase two, installed in 1963, covers the remainder of the field. Devonian salt water is injected into twenty-seven wells. (See Figure 1). The water is taken, by a submersible pump, from a well drilled to the Dawson Bay formation.

In March, 1965, 2½ years following unitization, the production rate had increased from the pre-flood rate of 2,900 BOPD to 4,750 BOPD. Over-all performance has been better than calculated due to a more rapid response in the central area of the field. Indications are that the ultimate recovery of 55,000,000 barrels will be achieved or exceeded. (See Figure 3).

## GEOLOGY

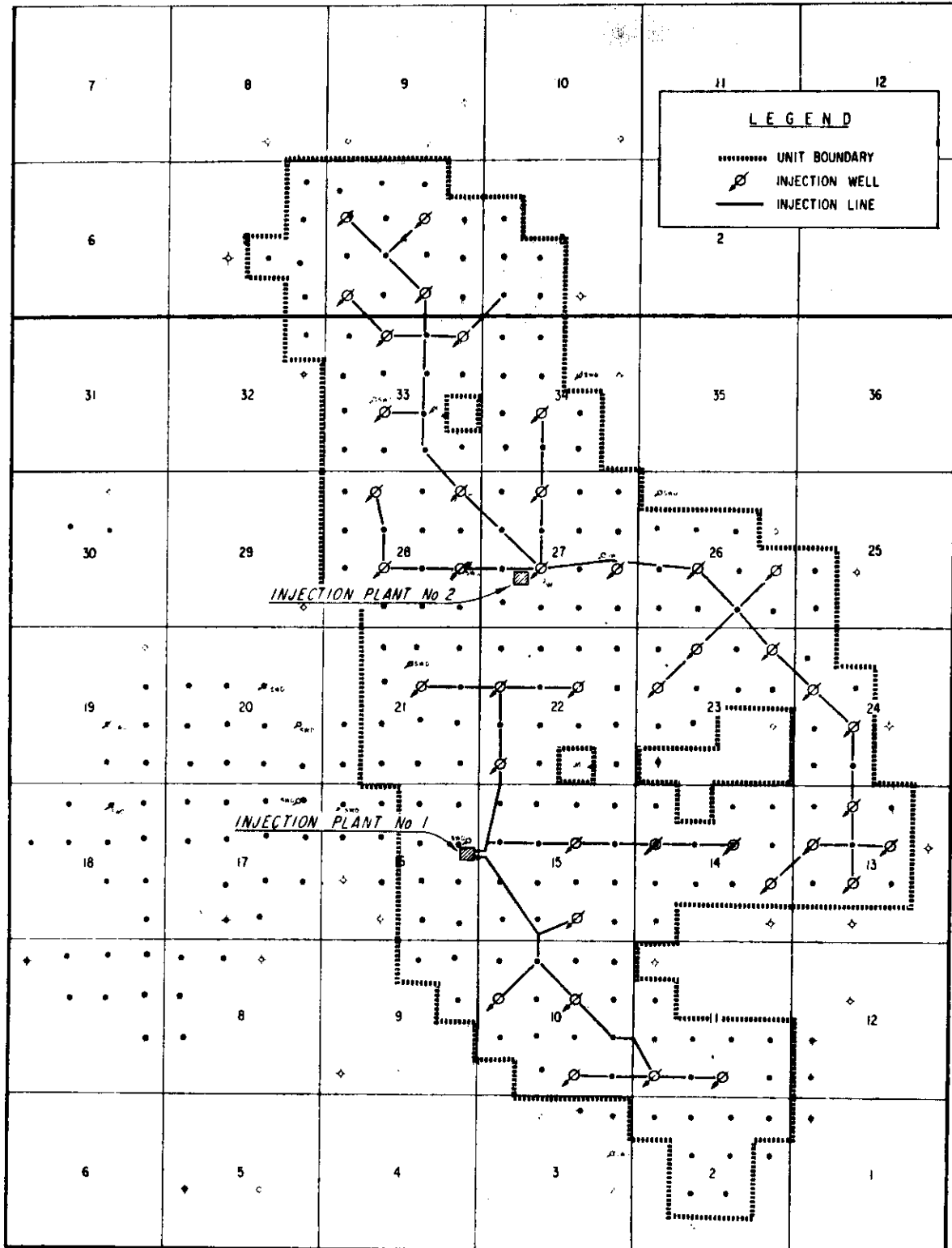
The North Virden Scallion field lies on the north-east flank of the Williston Basin. The reservoir is a stratigraphic trap in the Lodgepole formation of Mississippian age, with the limits partially controlled by a structural nosing. The reservoir rocks are mainly clastic limestones sub-divided by thin interbeds of argillaceous limestone. The Lodgepole formation has been sub-divided into three members: The Whitewater Lake, the Virden and the Scallion — in order of increasing depth.

The Whitewater Lake member, due to dolomitization, is not productive within the limits of the field. The Upper Virden member, a bioclastic limestone of mainly crinoidal debris, is called the Crinoidal zone. This zone is only productive in the southern portion of the field and averages 9 feet in thickness. The Lower Virden member consists mainly of oolitic limestones interbedded with argillaceous limestone or calcareous shale, and is called the Oolitic zone. These oolitic zones are cyclic in nature and total four in the area — the First, Second, Third and Fourth Oolites. This zone has an average thickness of 7 feet and is predominant in the eastern and southern portions of

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Figure 1.—North Virden Scallion Unit No. 1, as of December 31, 1964.

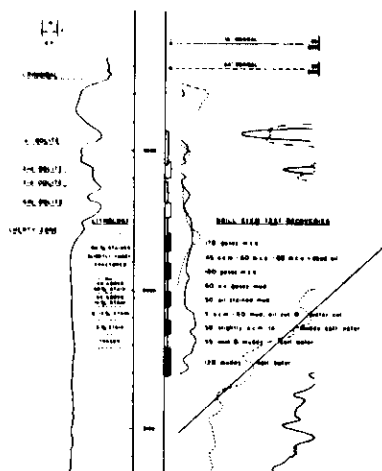


Figure 2.—Electric Log of Calstan Scallion 5-11-11-26, showing Variation of Oil Saturation with Depth.

the field. The main productive zone is the Cherty zone, which is the upper productive portion of the Scallion member. (See Figure 2). This member is predominantly a finely crystalline cherty limestone. The Cherty zone was leached in the central portion of the field, thus increasing the porosity and permeability.

The Scallion member is approximately 200 feet thick, and the Cherty zone pay averages 26 feet in thickness over most of the field limits. Fracture systems, sometimes anhydrite-infilled, have generally developed in wells that are located where the Lodgepole is structurally high due to post-Lodgepole movement.

Down dip on the southwestern edge of the field, the pay zones are water bearing and have developed an active water drive. The Scallion member below the productive Cherty zone is water bearing. The base of effective oil saturation is extremely difficult to determine, as it fluctuates from well to well.

#### DEVELOPMENT

The discovery well, Calstan Scallion 3-11-11-26, encountered commercial oil production in the Oolitic zone in December, 1953. Development of the field followed rapidly, and by year-end 1956 there were 171 wells capable of production. In spite of further drilling, to a total of 274 wells in 1961, the total field production began to decline in late 1956.

Initially, the most common completion technique was open hole, with the Oolitic and Cherty zones open. Later, cased-through completions were utilized and the pay zones were perforated. Most wells were stimulated on completion with a mud-acid wash followed by an acid squeeze although some later wells were hydraulically fractured. More than 50 per cent of the wells have been reworked at least once, and more than 60 per cent have had frac treatments. All wells were put on pump soon after completion.

#### RESERVOIR AND FLUID PROPERTIES

The core of approximately one-quarter of the wells in North Virden was analyzed, but only one-half of these were cored to the base of effective oil saturation in the Cherty zone.

One of the most difficult parameters to determine was the effective pay thickness. There are numerous

TABLE I

	Cherty Zone	Oolitic Zone	Crinoidal Zone
1. Area — acres . . .	8,500	7,300	4,100
2. Pay thickness — ft. . . . .	25.6	6.8	9.5
3. Average porosity — % . . . . .	13.4	10.7	9.8
4. Connate water saturation — % . . . . .	29	29	48
5. Average permeability — md . . . . .	23	110	6
6. Original oil-in-place — bbls. . . . .	152,000,000	28,000,000	14,000,000
Per Cent of Total	79	14	7

unrelated tight streaks present throughout the pay sections, and in the Cherty zone the base of effective oil saturation had to be determined and contoured over the field. Complete core analyses were inadequate and the quality of most logs was poor. Core analyses, microlaterologs, core descriptions, electric logs, gamma-ray logs and neutron logs were used to determine the effective pay. Using these methods, isopachs of net pay and porosity thickness were drawn and planimetered to arrive at an average pay thickness and a porosity for each zone. (See Table I).

Connate water saturation tests were performed by many methods. One oil-base core was cut on Calstan Scallion 9-23-11-26. The relationship between water saturation and median permeability and between water saturation and porosity was analyzed for both the Cherty and Oolitic zones. Capillary pressure tests were run on Cherty and Oolitic core plugs. The restored-state method was used to analyze core plugs from both of these zones. A mercury injection capillary pressure test was run on one Cherty-zone sample. Weighting all this information gave connate water saturations for each zone. (See Table I).

Reservoir fluid studies were conducted on samples from three wells. Two of these samples had compatible results and indicated the following:

Saturation pressure . . . . .	145 psig
Solution GOR . . . . .	70 Scf/bbl
Initial Formation Volume Factor . . . . .	1.045
Oil Gravity . . . . .	34° API
Oil Viscosity @ Ps . . . . .	3.52 cp

Few static pressures have been taken in the field because of extremely long pressure build-up times. The initial reservoir pressure was just over 900 psig, but had dropped to approximately 200 psig over most of the field by 1962. The western flank pressure has been maintained at approximately 700 psig by water encroachment.

#### PRIMARY PERFORMANCE

The North Virden Scallion field was initially a highly undersaturated reservoir and the prime natural energy sources were combinations of oil expansion, edge-water encroachment and limited bottom-water drive. The solution GOR was 70 scf per barrel. Recovery due to oil expansion alone would have been 0.6 per cent without the natural water drives.

The initial producing rates of the Unit wells ranged from 3 BOPD up to the MPR of 70 BOPD. In 1956, when the Unit area production peaked at 6,000 BOPD, the average rate was 38 BOPD per well. At this point,

production rates began to decline, and the producing rate was 2,900 BOPD just prior to starting injection in November, 1962. The average production rate per well was then 15 BOPD. The cumulative production to the effective date of unitization was approximately 11,600,000 barrels. This represented a recovery of 6 per cent to that point.

Individual well decline curves were analyzed to determine the ultimate primary recovery, but many wells did not exhibit a definite decline.

The unit area production rate was plotted and exhibited a definite decline. Projection of the average daily production rate curve indicated an ultimate primary recovery of 13 per cent or 25,000,000 barrels. The production history of the Unit is shown on Figure 3.

### UNITIZATION

In addition to the usual cost and recovery incentives, an additional incentive to unitization and secondary recovery exists in Manitoba. Unitized waterfloods are unprorated to market demand. Once injection is commenced, the only limits on producing rates are good engineering practices. For the most part, each well is produced to either the capacity of the well or the capacity of the equipment on the well.

In 1958, a proposal to initiate a double five-spot pilot waterflood failed because the approval of all royalty owners could not be obtained. At that time, Manitoba had legislation for voluntary unitization only. This made unitization almost impossible. In 1959, Manitoba's legislation was changed so that compulsory unitization was possible if 75 per cent of the working interest and royalty owners agreed to the plan.

When the pilot flood was turned down, negotiations to unitize and waterflood the entire field started. Agreement was quickly reached on two points: (1) the southwest flank of the field should not be included, as a natural water drive was flooding this area, and (2) the usual factors for participation, namely pay thickness, porosity, pore volume and well factor, could not be used because the first three were almost impossible to determine and, in general, there was no consistent correlation between any of these factors and the performance of the individual wells.

When the usual volumetric factors could not be used, another means had to be found to determine participation. In Manitoba, because almost every well

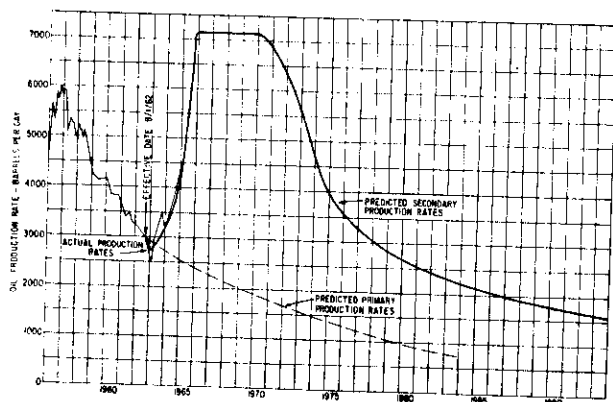


Figure 3.—Production History and Prediction. — North Virden Scallion Unit No. 1.

	Cherty Zone	Oolitic Zone	Crinoidal Zone
1. Average residual oil saturation (infinite WOR)....	34%	40%	25%
2. Initial oil saturation.....	76%	79%	67%
3. Average oil saturation at breakthrough.....	48%	62%	42%
4. Average oil recoveries at breakthrough.....	36%	20%	38%

produces to capacity, past and present production become good criteria for determining equity. Decline rates, current production rates and water cuts are the only reliable indicators of the past, present and future worth of each well or tract. Agreement was reached on the following formula for participation: 50 per cent weighting to current production over a six-month period and 50 per cent weighting to a cumulative average production rate penalized for current water production. The six-month period chosen was May-October, 1962. Cumulative production was to October 31st, 1962.

The plan for unitization and waterflooding was examined by the Oil and Natural Gas Conservation Board, Department of Mines and Natural Resources, at a public hearing in Virden, Manitoba, on April 18, 1962. It was approved in principle and the Unit became effective on August 1, 1962.

### SECONDARY PREDICTIONS AND PERFORMANCE

Waterflooding tests were run on twelve core samples in 1957 by the California Research Corporation. Seven of these were Cherty-zone samples. The pertinent results are shown on Table II.

In addition, relative permeability ratio ( $K_{rw}/K_o$ ) versus water saturation curves and  $K_{rw}$  at residual oil saturation versus  $K_o$  curves were provided. For flooding predictions, it was assumed that the Cherty zone was representative of all zones. The composite Cherty zone  $K_{rw}/K_o$  curve is shown on Figure 4. Utilizing the Cherty zone  $K_{rw}/K_o$  curve, Welge's method

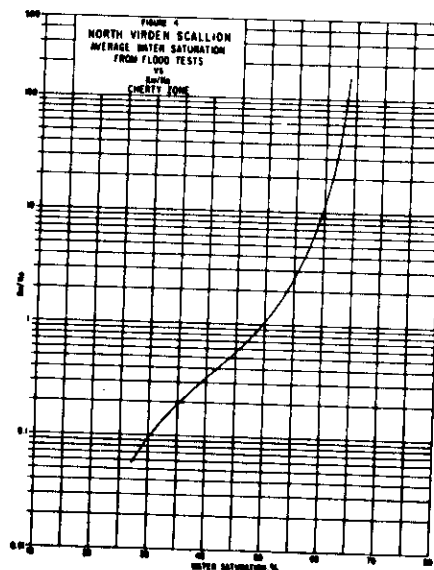


Figure 4.

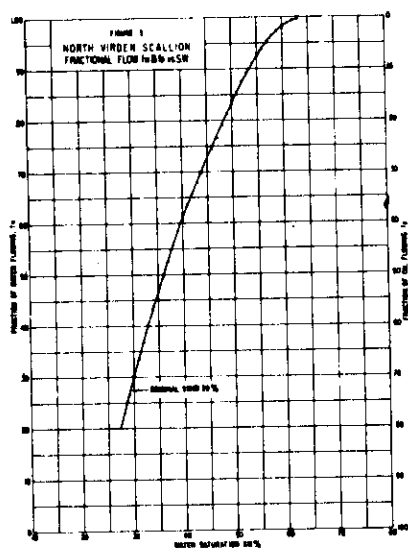


Figure 5.

(1) was used to calculate displacement efficiencies as a function of water-oil ratios. The fractional flow curve is shown on Figure 5.

A Dykstra-Parsons (2) permeability distribution plot for the Cherty zone (eighty-one wells) was constructed to obtain the permeability variation and the median permeability. (See Figure 6). Using the Dykstra-Parsons graphs for a linear permeability distribution, a mobility ratio ( $K_{rw}/K_{ro} \times u_o/u_w$ ) of 0.77 and a permeability variation of 0.76, the coverage or vertical sweep efficiency was determined as a function of the water-oil ratio.

Graphs drawn by Caudle, Erickson and Slobod (3), and Dyes, Caudle and Erickson (4) were used to determine areal sweep efficiencies as a function of water-oil ratios at a mobility ratio of 1.3. Their mobility ratio is the reciprocal of Dykstra-Parsons mobility ratio.

These three efficiencies were combined to obtain the recoveries at different water-oil ratios. The recovery to breakthrough was calculated to be 14 per cent of the oil-in-place at the start of flooding, or 25,400,000 barrels. The ultimate recovery was calculated to be 28.4 per cent or 55,000,000 barrels. This is an increase of 15.6 per cent over the ultimate primary recovery of 12.8 per cent. The limiting parameters in arriving at this ultimate recovery were (1) the Unit would only be produced to a 5.4:1 WOR, (2) the maximum fluid production would be 10,000 barrels per day and (3) the economic limit would be 7 BOPD per well.

Performance of the waterflood to date has been excellent. The production rate in November, 1962, the last month prior to conversion, was 2,900 BOPD. After conversion of eleven wells (Phase 1), the rate dropped to 2,700 BOPD in February, 1963. The rate increased to 3,500 BOPD in October, 1963, when twenty-nine more wells were converted (Phase 2). These conversions caused the rate to drop to 3,200 BOPD in December 1963. Since then, the rate has increased steadily to 4,750 BOPD in March, 1965. The net increase in production rate as of February 28, 1965, is 1,850 BOPD. Including an estimated natural decline of 450 BOPD, the total increase is 2,300 BOPD.

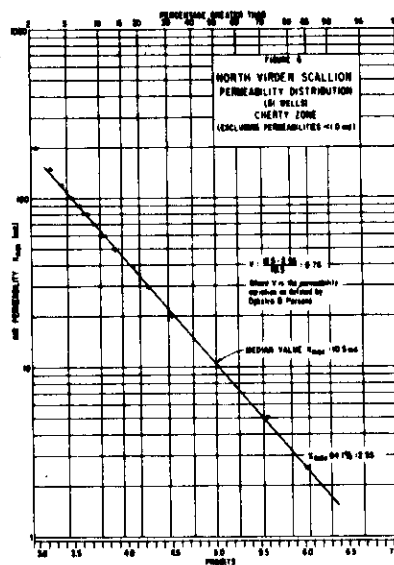


Figure 6.

The response in the majority of the offsetting wells in the Phase 1 central area was more rapid than anticipated. Some wells had shown good increases within two months. The effect of this rapid response was that the actual performance exceeded the prediction until the Phase 2 wells were converted. Response in the Phase 2 area and the south portion of Phase 1 has been as expected, with response occurring over a 4- to 6-month period, although it was not as marked as in the central Phase 1 area. For the past year, the actual performance has been almost exactly as predicted. The over-all performance to date has been better than predicted. (See Figures 7, 8, 9 and 10).

The eastern-edge wells have responded differently than those in the rest of the field. Over most of the field, an increased oil rate is accompanied by a decreased water cut. On the eastern edge, the water rate is following the oil rate and the water cut is either remaining constant or is increasing slightly. This is attributed to mobile connate water on the eastern edge. (See Figure 9). To March, 1965, no breakthrough has occurred.

Response of over 10 BOPD has occurred in fifty-nine wells — thirty in the Phase 2 area and twenty-nine in the Phase 1 area. These increases range from 10 to 115 BOPD and account for 2,040 BOPD out of the total increase of 2,300 BOPD.

Few problems have been encountered with the two injection plants, the injection system and the injection wells. Plant No. 1 injects produced Mississippian water into thirteen wells at an average rate of approximately 4,000 BWPD. This water is gathered from the entire Unit and some west-flank non-unit wells. The water is piped to the plant on Lsd. 9-16-11-26, where it is filtered and injected. Originally, a diatomaceous earth filter was used but, because of oil in the water, this proved unsatisfactory. The water is now passed through a hay section which effectively cleans it. The diatomaceous earth filter is no longer used. After filtering, two triplex pumps move the water through cement-lined steel pipe, which was field-wrapped with plastic tape, to the injection wells. The water is injected at an average pressure of 700 psig. The Phase 2 plant, which is a closed system, consists of two turbine pumps which accept water

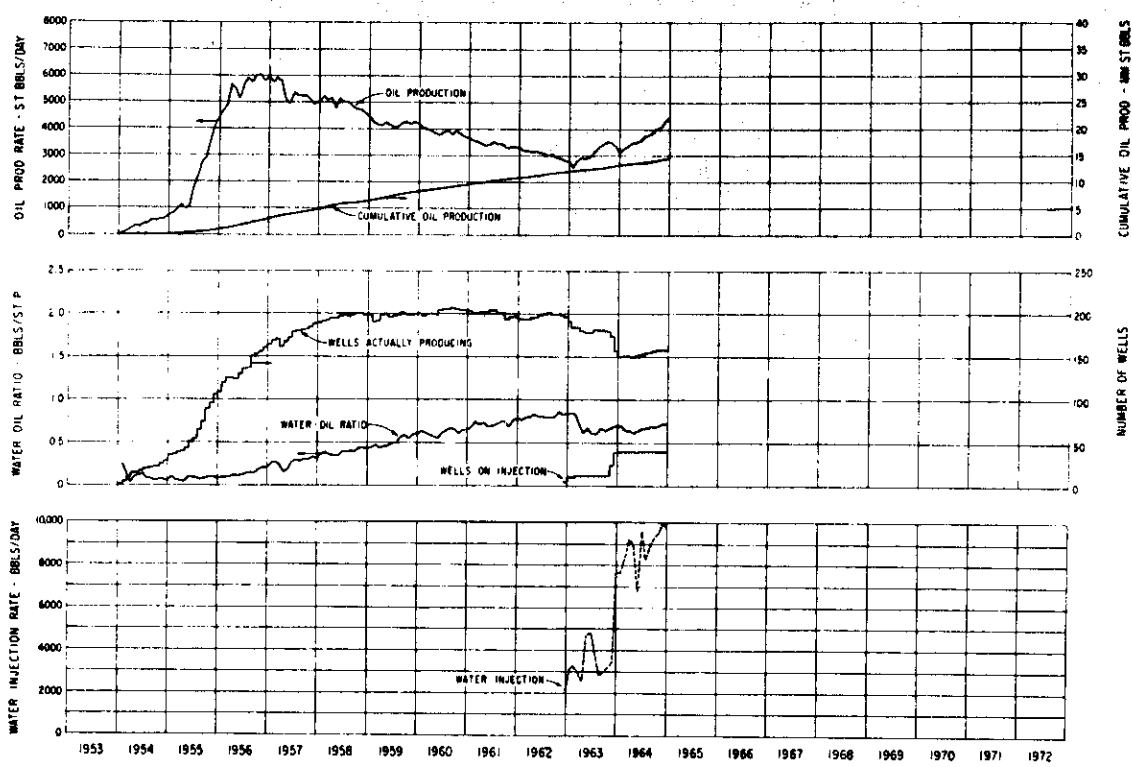


Figure 7.—Reservoir Performance — North Virden Scallion Unit No. 1.

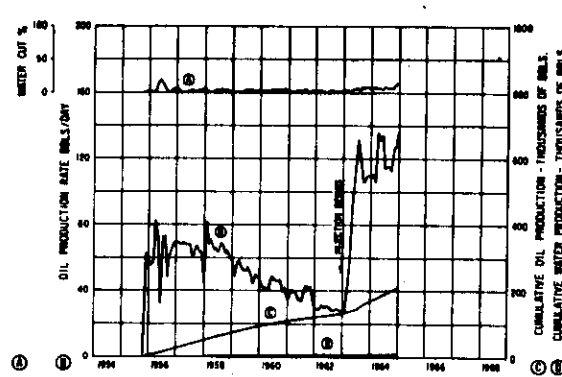


Figure 8.—Production History of Calstan Scallion 11-22-11-26.

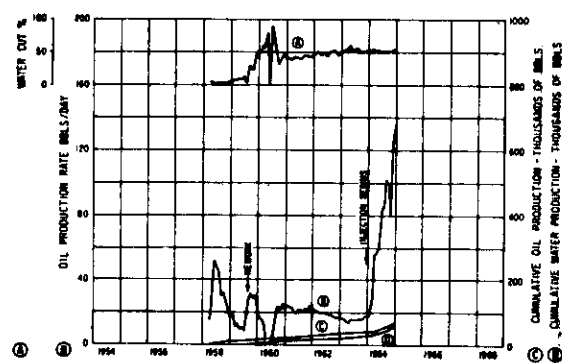


Figure 9.—Production History of Fargo et al., Scallion 9-14-11-26

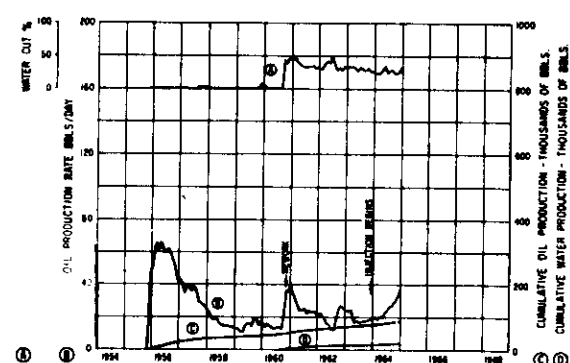


Figure 10.—Production History of Sun W. C. Tapp Scallion 15-27-11-26.

from a submersible pump set at 1,600 ft. in the Devonian salt-water supply well. This well is currently supplying 6,000 BWPD with a drawdown of 0.09 psi/BWPD. The water is not filtered or treated. The average injection pressure is about 500 psig. The water is carried to the wells through cement-lined, yellow-jacketed steel pipe.

In June and July, 1964, injection profiles were run on every injection well except 6-36-11-26. This well had an injection rate too low to survey. The purpose of this survey was to determine which zones were accepting water and to determine the distribution between zones or within zones. Radioactive tracer surveys were run on all perforated injectors and flow-meter surveys were run on open-hole completions. The over-all results of the survey indicated that all three zones are being effectively flooded and that the distribution of water between zones is good. The Oolitic zone, which has the highest permeability, is not taking as much water as originally expected. It was originally thought that high volumes of water would be injected into this zone and that breakthrough would occur fairly rapidly. This has not occurred. Some wells will require remedial action to improve injection into specific zones, and these reworks are currently under study. It was noticed that most wells had communication between zones behind the pipe, which could complicate remedial action.

A chemical tracer, ammonium thiocyanate, has been injected into nineteen of the forty injection wells. This should facilitate detection of the source of injection water then breakthrough occurs. It will only be necessary to determine which of two wells is responsible for the breakthrough. In some cases, the offending injector will be marked by the presence of the chemical, or in other cases, by the absence of it.

The California Standard Company is currently constructing a digital computer model to simulate this flood. The model assumes that the system is two-dimensional, the fluids are incompressible, gravity and capillary forces have no effect on the shape of the flood front, the flood front interface is sharp and the mobility ratio is unity. To date, the basic data have been assembled. The necessary data required were as follows: (1) a grid with three points between wells and each grid point identified, (2) isopachs of pay, porosity, permeability, porosity feet and permeability feet, with a value assigned to each grid point, (3) pressures assigned to each well, (4) production and injection histories and (5) permeances calculated for all boundary points and injection wells. In April, 1965, using the above data, an attempt will be made

to postulate the path and position of the flood front at certain stages of the life of the Unit. With this information, better control of flood fronts should be possible.

The North Virden Scallion field has responded well to water injection. Producing rates have been significantly increased and are currently on the predicted trend. Indications are that the calculated ultimate recovery of 55,000,000 barrels will be achieved.

#### ACKNOWLEDGMENTS

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