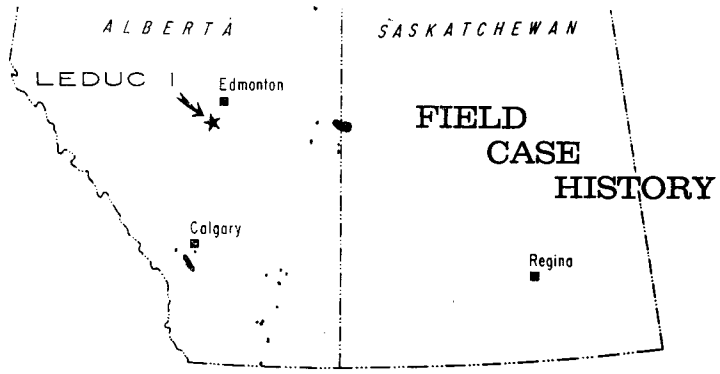

FIELD CASE HISTORY

Performance of the Leduc D-3 Reservoir

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Abstract

The Leduc D-3 pool was discovered in 1947 at a depth of 5,300 ft and is one of Canada's major oil fields. The relatively thin oil zone covers an area of 21,640 acres and originally contained more than 400 million bbl of oil in place. It is overlain by a large gas cap and underlain by more than 900 ft of water-bearing reef.

The history of this pool has been outstanding in many ways. The early behavior of the reservoir was dominated by the effects of a wild well which blew oil and gas for six months. Subsequent history indicated that the recovery mechanism consisted almost entirely of gas cap and water drives; however, during 1953, an increase in the rate of pressure decline indicated interference by neighboring pools through a common aquifer. A cooperative committee including almost all Leduc D-3 operators was formed and water injection was instituted in Sept., 1955, to maintain the reservoir pressure and eliminate further shrinkage losses. This project is unique in that pressure is being maintained uniformly throughout the pool with the use of only one injection well which is capable of taking more than 65,000 B/D on vacuum. After one-quarter of the oil in place had been produced, the increase in gas-oil ratio was slight and only one of 535 wells had been abandoned. This pool saw the first application of tubing-submergence completions in Canada and these wells, like most of those completed in a more conventional manner, are still capable of flowing production at rates in excess of 100 B/D without harmful effects.

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Introduction

Discovery of the Leduc field in 1947 made oil history in Canada. After more than a decade of fruitless wildcatting in Southern Alberta and Saskatchewan, exploration activity moved northward and Imperial Leduc 1 was spudded 12 miles southwest of the City of Edmonton in Central Alberta. (At the top of this page is a map of the oil pools in Western Canada.) This well encountered oil at a depth of 4,900 ft and established the Leduc D-2 pool. The follow-up well, Imperial Leduc 2 was drilled 1 mile south and, after penetrating the D-2 reservoir, discovered the underlying Leduc D-3 pool at a depth of 5,300 ft. Both pools have proven to be major finds, each containing more than 400 million bbl of oil in place and each having more than 500 wells on 40-acre spacing. However, of the two main reservoirs in the Leduc field, the history of the D-3 pool has been the more eventful and unpredictable.

Geology

The geology of the Edmonton area in the Central Plains of Alberta is indicated by the table of formations shown in Fig. 1. The thicknesses shown have particular reference to the Leduc field. The regional dip is approximately 50 ft/mile in the southwest direction with most of the thickening occurring in the Cretaceous sediments.

The Upper Devonian carbonate-shale series is the prime target of most wells in the Edmonton area although significant localized reserves of oil and gas have been encountered in the Viking and Basal Blairmore sandstone members of the Lower Cretaceous sand-shale series. It lies unconformably below the Cretaceous with the D-1 member being partially eroded and generally barren of hydrocarbons. The D-2 carbonate zone is separated from the D-1 by silty shales and lies as a continuous "biostrome" or sheet-type reefal dolomite. It is productive from many structural and stratigraphic traps which are complementary to the underlying D-3 member. The D-3 carbonate member consists of "bioherms" or isolated reef build-ups overlain by calcareous shale and underlain by a

EDMONTON AREA
ALBERTA

ERA	PERIOD		GROUP OR FORMATION	THICKNESS
CENOZOIC	QUATERNARY		Glacial Deposits, Soil, River Gravels and Sand	50'
MESOZOIC	CRETACEOUS	UPPER CRETACEOUS	EDMONTON	1,000'
			BELLY RIVER	900'
			LEA PARK	500'
			COLORADO / VIKING	1,300'
		LOWER CRETACEOUS	BLAIRMORE / BASAL BLAIRMORE	700'
PALAEOZOIC	DEVONIAN	UPPER DEVONIAN	WABAMUN (D-1)	550'
			WINTERBURN: GRAMINIA, CALMAR; NISKU (D-2)	250'
			WOODBEND: IRETON, LEDUC (D-3); DUVERNAY; COOKING LAKE	1,150'
			BEAVERHILL LAKE	700'
		MIDDLE DEVONIAN	ELK POINT	700'
	CAMBRIAN		undifferentiated	1,100'
	PRECAMBRIAN			

Fig. 1—Table of formations, Edmonton area, Alberta.

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reefal fragmental "Cooking Lake" limestone platform. Several of these reefs have been found to contain large oil and gas reserves in the Edmonton area, including the Leduc D-3 pool.

The Leduc D-3 reef extends over more than 22,000 acres and, with the Cooking Lake member, has a maximum porous thickness in excess of 1,100 ft. The structure map in Fig. 2 shows the broad areas of reef build-up with steeply dipping sides characteristic of a true bioherm.[1,2] The porosity consists mainly of vugs interconnected through the dense matrix by small crevices and fractures.

Development and Completions

Development of the Leduc D-3 pool was fairly slow for several reasons. Drilling activity in Western Canada had been at a relatively low level for several years and the previous lack of exploratory success had bred a feeling of caution. Also, drilling techniques had to be developed to combat the peculiar problems encountered, such as serious lost circulation in the gas cap of the D-3 pool. After one full year of operation, only 30 D-3 wells and two dry holes had been drilled. Nevertheless, when added to the development of the overlying D-2 pool, this represented a sharp increase in Canada's oil activity.

As it became clear that an oil pool of major proportions had been found, the development rate increased and, by mid-1949, industry had drilled 195 D-3 wells and 14 dry holes. During this period two other major oil fields, Redwater and Golden Spike, and some smaller pools such as Excelsior had been discovered and were also commencing active development. Due to the resultant spreading of activities, the development rate in the Leduc D-3 pool declined to about 75 oil wells per year. Development was not completed until the end of 1954 when 535 oil wells and 57 dry holes had been drilled on Alberta's basic 40-acre spacing pattern.

Numerous drill-stem tests had shown that the Leduc D-3 pool was composed of four areas with different gas-oil and/or water-oil contacts. These areas are indicated in Fig. 3.

[1]References given at end of paper.

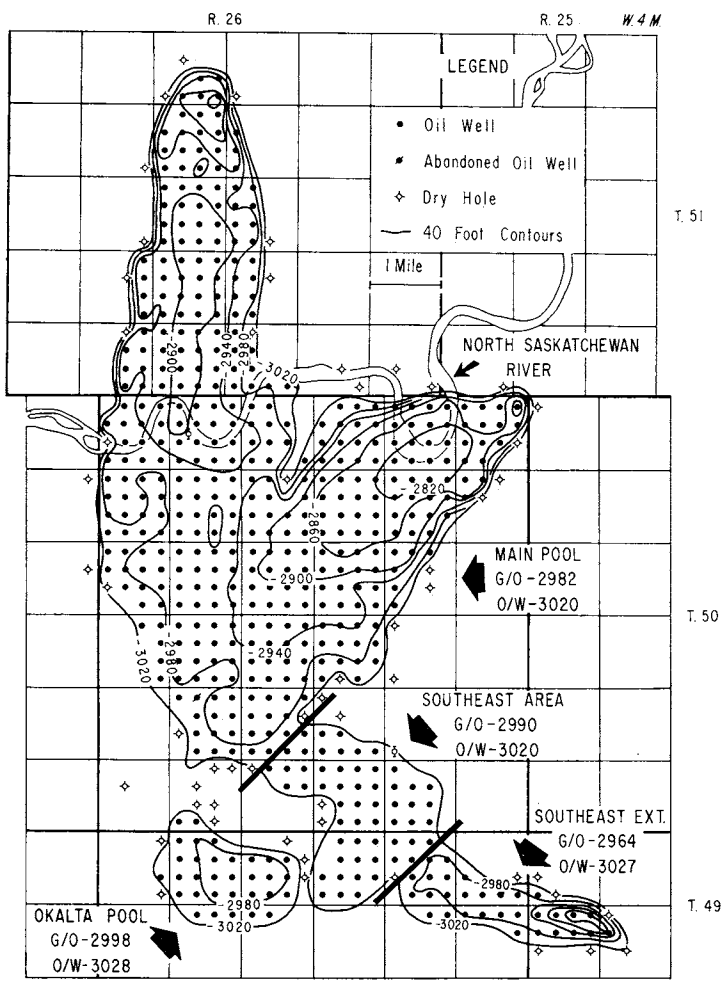

Fig. 2—Structure of Leduc D-3 reef.

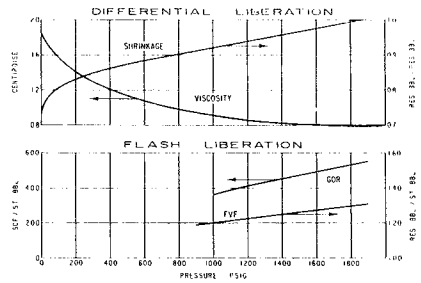

Fig. 3—Reservoir oil analysis.

Main Pool

The northern main portion of the pool, containing 472 oil wells, was found to have gas-oil and water-oil contacts at 2,982-and 3,020-ft subsea, respectively. The 38-ft oil zone was overlain by a large gas cap ranging up to 158 ft in thickness. Due to the thinness of the oil zone and the steeply dipping sides of the thick reef, all but a few edge wells encountered gas cap.

Southeast Area

The southeastern neck of the pool was found to have the same water-oil contact as the main portion of the pool, but the gas-oil contact was established to be 8 ft lower at 2,990-ft subsea. Although the 30-ft oil zone in this area is connected with the main reservoir, the gas caps are separated by a small saddle in the D-3 structure.

Southeast Extension

The southeast extension of the pool exhibited gas-oil and water-oil contacts at 2,964- and 3,027-ft subsea, respectively. The reservoir in this area is believed to be separated from the remainder of the pool by a deep saddle which was undetected by drilling on the 40-acre spacing pattern.

Okalta Pool

The small area to the south of the main pool is called the Okalta pool and is known to be a separate oil accumulation in a local high of the Leduc reef. The gas-oil and water-oil contacts are at 2,998-and 3,028-ft subsea, respectively.

All four areas are underlain by a common 900-ft thick aquifer and are considered as a single pool for the evaluation of reservoir performance. The total productive area covers 21,640 acres.

The large majority of the wells in this pool were completed with casing or liners run to bottom and perforated in a 5-ft interval near the center of the oil zone. However, several tubing-submergence completions were made wherein the casing was set at the top of the D-3 and tubing was run with or without a packer into the oil zone. The latter type of completions are de-

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pendent on low pressure drawdowns which will not remove the oil seal between the gas cap and tubing perforations.

Rock and Fluid Characteristics

The vuggy nature of the reservoir rock forced the early development of full-diameter core equipment and techniques for the analysis of rock characteristics.[3] Even with this equipment infinite dry air permeabilities were frequently obtained from laboratory tests of very vuggy samples, and for this reason it is difficult to evaluate average reservoir permeabilities from core analysis.

Porosity profiles of 35 large-diameter diamond cores taken from this pool showed very erratic distributions of porosity as a function of depth. Individual values varied from 2 to 20 per cent of the rock volume. A thorough study of the porosity distribution together with a comprehensive geological study of the facies types has led to a value of 8.0 per cent for the average porosity of this reservoir. This value was substantiated by the complete analysis of two deep wells which cored the entire porous interval below the water-oil contact.

Numerous productivity tests have been conducted on the wells to determine the permeability characteristics of the reservoir. The PI's showed a wide range of values. Some of the poorer wells had values as low as 0.035 B/D/psi and were found to be producing excess gas or water as a result of coning. However, the large majority of the wells had PI's greater than 5 B/D/psi. Since most of the wells have an open section of only 5 ft in the relatively thin oil zone, the average SPI was calculated to be at least 1 B/D/psi/ft of open section. Application of Darcy's law to these figures gave an average horizontal permeability in excess of 1,000 md.

During the drilling of a deep test, Imperial Leduc 530, which penetrated the D-3 reef, several drill-stem tests were run with a sensitive pressure gauge in the tailpipe in an attempt to measure the vertical flowing pressure gradient in the aquifer. This pressure gradient, together with the knowledge of the rate of water influx determined from the volumetric balance, might indicate the average vertical permeability of the reef. Results of this test indicated an average vertical permeability of at least 5 md; however, slight variations in the data obtained from this sensitive test resulted in wide variations in the calculated permeability. It was concluded that the test results substantiated the indication from core analyses that the vertical permeability of the Leduc D-3 reef was considerably less than the average horizontal permeability.

Restored-state tests run in the laboratory on 11 core samples yielded irreducible water saturations in the range from 6 to 26 per cent of the pore volume. Distillation of an oil core taken from Imperial Leduc 602 gave an average connate water saturation of 11 per cent. From these limited data, the average connate water saturation of the reservoir was assumed to be 15 per cent of the pore volume.

Several subsurface fluid samples have been obtained from the Leduc D-3 reservoir. The analysis of the sample taken from Imperial Leduc 6 is believed to be the most representative and is shown in Fig. 3. The reservoir oil was saturated at the original pressure of 1,894 psig at the datum elevation of 2,980-ft subsea and a temperature of 150°F. The differential liberation curve shows that the reservoir oil would shrink to 71.6 per cent of its original volume if the reservoir pressure was allowed to decline to atmospheric. The flash liberation curve shows that each barrel of original reservoir oil would yield 0.765 STB and, in so doing, it would release 553 cu ft of dissolved gas. The viscosity of the reservoir oil was 0.78 cp under original reservoir conditions.

The analysis of a gas-cap sample caught from a drill-stem test is shown in Table 1. The gas conversion factor, or v-factor, calculated from the composition of the gas sample, is shown in Fig. 4. Under original reservoir conditions, 1 Mscf of gas-cap gas occupied 1.281 bbl of reservoir volume.

The gravity of the oil production from Leduc D-3 pool is approximately 39° API. Small amounts of hydrogen sulfide are present in the Okalta pool but none is present in the other areas.

The original volume of oil in place was calculated to be 401,841,000 reservoir bbl. The gas cap occupied a volume of 553,140,000 reservoir bbl. The reservoir factors used in the volumetric calculation are summarized in Table 2.

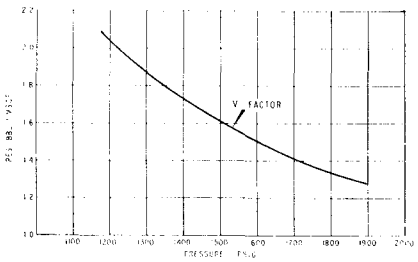

Fig. 4—Gas conversion factor.

Reservoir Performance

The pressure-production history of the Leduc D-3 pool is shown in Fig. 5. Numerous measurements proved that the original reservoir pressure was 1,894 psig at the datum level of 2,980 ft subsea. The initial GOR measurements were erratic but extrapolation of the subsequent trend in GOR's indicates that the original value was in the order of 550 scf/bbl as indicated by the laboratory analysis of the subsurface samples. During the first year of operation the daily production rate from the pool increased in proportion to the development rate and the reservoir pressure declined slightly.

In March, 1948, Atlantic 3, drilling on the eastern edge of the pool, blew out of control. The production casing had not been set in the well and large volumes of D-3 oil and gas blew from craters in the ground around the well. The well was finally killed in Sept., 1948, by the injection of water into a relief well. During the six months of uncontrolled production, the oil flowing on the surface was gathered in earthen pits and salvaged. This oil is included in the production history shown in Fig. 5. However, unknown quantities of oil were lost by surface seepage and influx into thief zones in the well. Since the blowout occurred above the oil zone, the wild well produced large volumes of gas-cap gas. When the main production from this well was directed to a separator, gas-oil ratios in the order of 30,000 scf/bbl were measured. On this basis, it was estimated that the well produced 28 billion scf of gas during the blowout period. The large withdrawal of oil and gas, offset only slightly by the injection of about 1 million bbl of water

TABLE 1—ANALYSIS OF RESERVOIR AND PRODUCED FLUIDS

Mol per cent Component	Gas-Cap Gas	Separator Gas (100 psig)	Reservoir Oil	Stock-Tank Oil
Methane	73.16	67.88	26.93	0.93
Ethane	9.97	17.03	11.69	3.90
Propane	4.71	8.74	9.38	8.24
Iso-butane	0.53	0.91	2.03	2.49
n-butane	1.35	1.67	4.29	5.76
Iso-pentane	0.28	0.31	1.18	3.35
n-pentane	0.28	0.26	2.41	3.31
Hexanes plus	0.32	0.28	41.39	72.02
Carbon dioxide	0.10	0.05		
Nitrogen	8.80	0.38		
Oxygen	0.50	2.49		
Specific Gravity	0.736	0.795	0.721	0.797

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TABLE 2—SUMMARY OF RESERVOIR FACTORS AND CALCULATION OF OIL AND GAS IN PLACE

Oil Zone	
Productive area, acres	21,640
Average pay thickness, ft	35.2
Gross rock volume, acre-ft	761,720
Average porosity, per cent	8.0
Connate water saturation, per cent	15
Original oil volume, reservoir bbl	401,841,000
Flash shrinkage	0.765
Stock tank oil in place, STB	307,408,000
Gas Cap	
Gross rock volume, acre-ft	1,048,520
Original gas-cap volume, reservoir bbl	553,140,000
v-factor	1.281
Gas in place, Mscf	431,802,000

into the offsetting and relief wells, resulted in a sharp decline of 50 psi in the reservoir pressure during the blowout period.

The production rate from the pool remained relatively constant during the three years following the blowout due to the net effect of increasing development and decreasing allowables. The reservoir pressure declined accordingly at a uniform rate of about 1 psi per month. Increasing rates of production during 1952 and 1953 accelerated the rate of pressure decline and the allowable was reduced to prevent excessive shrinkage losses in the reservoir. However, the reservoir pressure did not respond as readily as had been predicted by reservoir studies.

Reservoir Studies

A volumetric balance confirmed the existence of a combination-drive mechanism. The contribution of each component drive to the replacement of oil withdrawals is shown in Fig. 6. To 1954, the water drive had contributed 50 per cent, the gas-cap drive had contributed 40 per cent and solution-gas drive had contributed 10 per cent to the replacement of reservoir oil. The periodic fluctuations in the three drive indices were caused by the rate-sensitive nature of the drive mechanism and by small but significant errors in pressure measurements. An analysis of the unsteady-state behavior of the aquifer[4], based on the results of the volumetric balance, yielded the "C-constant" history shown in Fig. 7. After the initial few years of erratic production history, the "C-constant" held steady until 1953 when it began to decline. This behavior was interpreted as an indication of either a limited aquifer confined to the Leduc reef and underlying Cooking Lake member, or interference by other pools with a common aquifer through the continuous Cooking Lake member.

The Leduc D-3 pool history was set-up on a Carter-type electric analyzer[5] to allow a more accurate representation of the known aquifer configuration. The history of the pool to 1954 could not be matched by the assumption of a limited aquifer, but could be approximated by the assumption of interfering pools located beyond the confines of the Leduc D-3 reef.

Pool Interference

Other discoveries subsequent to that of the Leduc D-3 pool have proven the existence of a straight-line chain of oil-bearing D-3 reefs extending to the north and south of the Leduc field. The relative locations of these pools are shown in Fig. 8 and their individual characteristics are given in Table 3. Due to the regional dip, the depths of these reefs vary from 4,650 ft for St. Albert in the north to 8,000 ft for Homeglen-Rimbey in the south. The pressure histories of these pools, when corrected to a common datum elevation, confirm the occurrence of pool interference. This is shown in Fig. 9.

The Golden Spike South D-3 pool, located 5 miles northwest of the Leduc D-3 pool, has been proven by field tests to have no water drive. This is consistent with the fact that the base of the oil zone in this pool was found to be tight in all wells. It is significant that the original pressure in this adjacent pool was the same as that of the Leduc D-3 pool, although discovered two years later. It is also significant that the distant Homeglen-Rimbey, Westerose and Bonnie Glen D-3 pools, which have high expansibilities due to very large gas caps, all had about the same discovery pressures relative to that of the Leduc D-3 pool. These pools were discovered during 1952-1953, after the Leduc D-3 pressure had declined more than 100 psi. For this reason, it is believed that all pools in the reef chain were in pressure equilibrium at the time of discovery of the Leduc D-3 pool.

The relatively lower discovery pressures of neighboring D-3 pools with lower expansibilities indicate the occurrence of prior interference through a common aquifer. The discovery pressures of these pools are mutually inconsistent unless considered relative to the pressures of the other pools at the time of their discovery. It is also significant that the pressure histories of these pools parallel each other and

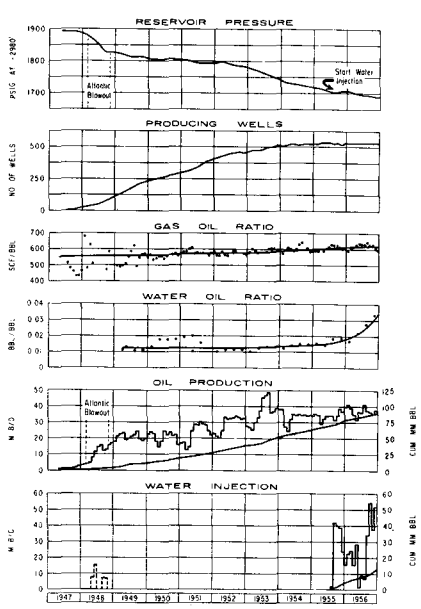

Fig. 5—Leduc D-3 pressure-production.

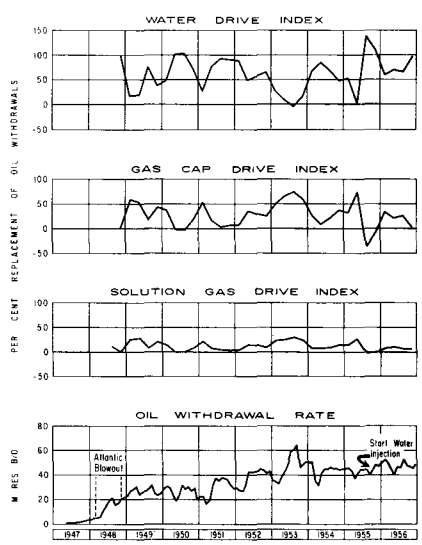

Fig. 6—History of drive indices.

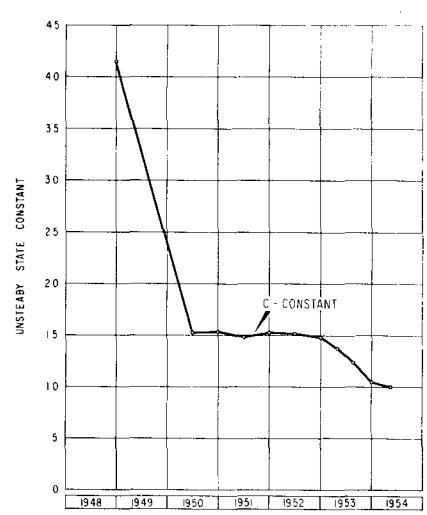

Fig. 7—History of unsteady-state constant.

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TABLE 3—D-3 POOL CHARACTERISTICS, LEDUC TREND

(An average salt water gradient of 0.498 psi/ft was used to refer pressures to Leduc datum)

D-3 Pools	Average Depth (ft)	Areal Extent (acres)	Original Gas-Cap Thickness (ft)	Original Oil Zone Thickness (ft)	Average Porosity per cent	Connate Water per cent	Original Gas-Cap Volume (1000's res. bbl)	Original Oil in Place (1000's res. bbl)	Total Reservoir Expansibility (res. bbl / psi)	Discovery Date (year)	Discovery Pressure (psig)	Subsea Datum Depth (ft)	Discovery Pressure Leduc D-3 Datum (−2,980 ft)	Remarks
St. Albert	4,645	330	Nil	51	9.9	15	Nil	10,987	102	1952	1,600	2,500	1,839	
Big Lake	4,780	200	Nil	150	12.81	20	Nil	23,851	230	1956	1,623	2,640	1,783	Development incomplete
Acheson	5,008	3,520	Nil	89	9.06	20	Nil	176,157	1,760	1950	1,730	2,700	1,864	Small original gas cap ignored
Acheson South	5,090	120	Nil	18	9.0	15	Nil	1,282	14	1955	1,659	2,773	1,766	Development incomplete
Golden Spike South D-3	5,627	1,120	Nil	520	9.16	20	Nil	331,098	3,810	1949	2,095	3,300	1,890	
Leduc	5,309	21,640 Oil 17,120 Gas	61	35.3	8.0	15	553,140	401,841	262,000	1947	1,894	2,980	1,894	
Glen Park	6,226	480	Nil	112	10.0	15	Nil	35,451	408	1951	2,201	3,750	1,801	
Wizard Lake	6,308	2,100	Nil	326	8.5	6.75	Nil	421,000	4,840	1951	2,266	3,750	1,838	
Bonnie Glen North	6,911	40	Nil	15	9.8	15	Nil	388	6	1956	2,280	4,232	1,676	Development incomplete
Bonnie Glen	6,993	6,120 Oil 3,160 Gas	237	221	9.3	6	535,230	809,400	232,000	1952	2,477	4,100	*1,891	
Westerose	7,190	1,840 Oil 1,040 Gas	223	189	9.6 Oil 7.7 Gas	20	110,830	207,200	48,400	1952	2,552	4,280	1,887	
Homeglen-Rimbey	8,000	14,000 Oil 14,000 Gas	162	25	7.9	13	1,209,000	186,585	409,000	1953	2,835	4,855	1,905	Development incomplete

that of the Leduc D-3. The movement of the pressure sink in the aquifer from the Leduc D-3 pool southward to the Wizard Lake pool in 1953 coincided with the abnormal behavior of the Leduc D-3 pool.

Pressure Maintenance

The advent of interference was undesirable from the standpoint of accelerated pressure decline and corresponding shrinkage losses in the Leduc D-3 reservoir. Injection of water into the aquifer to maintain reservoir pressure offered the only corrective solution to this problem. On June 28, 1954, Imperial Oil Ltd., on behalf of itself and other interested operators, made a submission to The Petroleum and Natural Gas Conservation Board requesting approval for pressure maintenance by water injection. Approval was granted on July 21, 1954, for the injection of up to 65,000 B/D into the Leduc D-3 aquifer. All but three operators of five wells joined into a cooperative agreement to participate in the project on a per-well basis to share the cost of installing and operating the system.

Experience obtained during the taming of Atlantic 3 contributed greatly to the design of the water injection project. During the blowout, water had been injected into the thin pay section of an offset well at rates up to 40,000 B/D under gravity feed. Therefore, it was believed that a single injection well, completed with several hundred feet of open hole in the reef below the oil-water contact, would be capable of injection at the rate required to replace withdrawals. Further, since surveys taken during the blowout had shown uniform pressures throughout the pool despite the concentration of withdrawals at the wild well, it was believed that the single injection well would satisfy pool-wide pressure maintenance. Finally, the injection of raw river water into the relief hole had not damaged the injection capacity of the well, indicating that filtration of the injection water would not be necessary.

The injection well was drilled on the south bank of the North Saskatchewan River to minimize the length of the large-diameter suction line. The 9⅝-in. injection string was landed 200 ft below the original oil-water contact and 800 ft of 8½-in. hole was opened in the reef below it. A 24-in. water intake line feeds water directly from the river into a concrete pump shaft and a pump discharges the unfiltered water through 100 ft of buried 10-in. line to the injection well. The total cost of the injection system was $240,000 or approximately $450 per producing well.

Initial well tests proved that the injection system was capable of syphoning water from the river into the reservoir at a rate of 32,000 B/D and that, under pumping operation, the well would take at least 65,000 B/D on wellhead vacuum. Subsequent tests have shown no deterioration in injection capacity.

The water injection project was put into sustained operation on Sept. 2, 1955. The subsequent pressure-production-injection history is shown in Fig. 5. The average daily injection rate varied widely due to the practice of injecting at high rates only when the river water was clear. The project was shut-down whenever the turbidity of the water exceeded 50 ppm of solids. These variations in injection rates were reflected in the pressure history by fluctuations in the pressure between 1,709 and 1,691 psig about the pre-injection value of 1,700 psig. The cumulative injection of 18.5 million bbl of fresh water to May, 1957, had arrested the reservoir pressure decline and the increasing GOR. The water-oil ratio increased only slightly and remained insignificant. It is estimated that to May, 1957, water injection had prevented the loss of 1 million bbl, which would have occurred by shrinkage of the reservoir oil under natural depletion.

Although seven wells in the immediate vicinity of the injection well have commenced water production, several pressure surveys have shown that the pressure is being maintained uniformly throughout the pool.

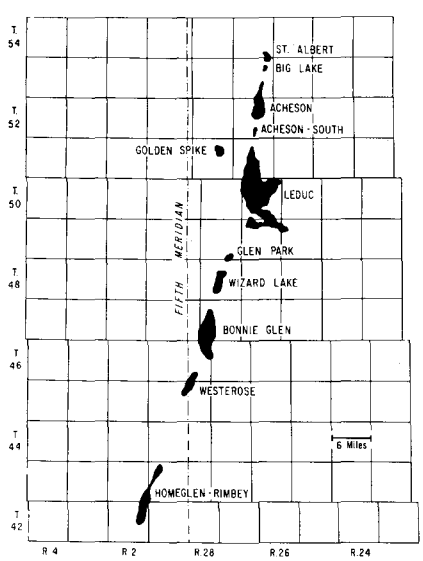

Fig. 8—Leduc D-3 reef trend.

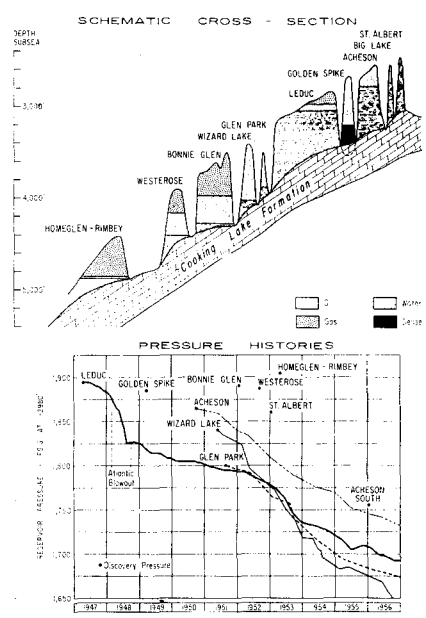

Fig. 9—Leduc D-3 pools.

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Reservoir Predictions

Predictions of reservoir performance of the individual D-3 pools in the Leduc trend are subject to error in varying degrees, if conducted without regard to interference effects. Since the performance of the reservoirs are mutually dependent, predictions of their behaviors can be handled best on an electric analyzer fitted with a pool or network unit. Such a study is in progress at the present time.

Regardless of the pressure behavior of the reservoir, it is apparent that the Leduc D-3 pool is approaching another stage of depletion which is difficult to predict. This will be the stage of increasing gas- and water-oil ratios.

Waterflood susceptibility tests and gas-oil relative permeability tests run on D-3 core samples from the various pools have indicated ultimate recoveries of 50 to 75 per cent HCPV by water and gas drives. Considering the gravity drainage potential of the Leduc D-3 reservoir with the overlying gas cap and underlying water zone, a conservative estimate of flushing efficiency by gas and water would be 55 per cent HCPV. On this basis, the historical behavior of the gas-oil and oil-water contacts in the Leduc D-3 pool would have been as shown in Fig. 10.

The elevation of the gas-oil contact during the early history was caused by the large withdrawals of gas during the Atlantic 3 blowout. During the following years of natural depletion, the contacts converged towards the center of the oil zone. After water injection was instituted in 1955, the descent of the gas-oil contact was arrested and the ascent of the water-oil contact was accelerated. By 1957, when 90 million STB had been produced, the effective thickness of the oil zone in the main area of the pool would have been reduced to approximately 20 ft.

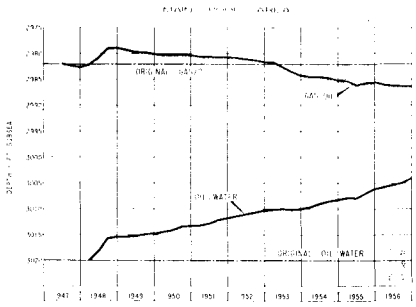

Fig. 10—History of gas-oil and oil-water contacts.

It has not been possible to observe the advances of the contacts by analysis of the production from individual wells, since most wells were completed with only a 5-ft open section near the center of the original oil zone. The excess gas and water being produced from a few wells can be attributed to either large drawdowns or mechanical failure of the completions. Four observation wells were recently established in this pool for the purpose of measuring the advances of the contacts. However, data from these wells are not available to date.

Considering the thin oil zone and the proximity of the completion interval to gas and water, it is remarkable that the wells in the Leduc D-3 pool are capable of sustained production at rates in excess of 100 B/D without significant gas or water coning. Only one edge well has been abandoned to date. Few wells in the similar Homeglen-Rimbey D-3 pool, which had an original 20-ft oil zone between a large gas cap and aquifer, will produce at this rate without excessive gas and water production. The excellent production characteristics of the Leduc D-3 pool are believed to be a consequence of the very high permeability of the reservoir and the large ratio of horizontal to vertical permeability.

It is apparent that the Leduc D-3 reservoir is approaching another stage in its production life which will require continued engineering studies to ensure maximum oil and gas recovery.

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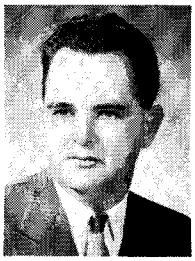

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