Spe 1209

RESERVOIR ENGINEERING

A Case History—Comparison of Predicted and Actual Performance of a Reservoir Producing Volatile Crude Oil

J. C. CORDELL — CONTINENTAL ILLINOIS NATIONAL BANK & TRUST CHICAGO, ILL.
C. K. EBERT — PAN AMERICAN PETROLEUM CORP. NEW ORLEANS, LA.
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Abstract

A case history of the depletion performance of a reservoir producing volatile crude oil is presented and compared with prior predictions of performance. The predicted performance was published by Jacoby and Berry in 1957.[1] The history concerns a field in North Louisiana discovered in late 1953, producing from the Smackover lime at approximately 10,000 ft. The volatile-oil reservoir covers 1,600 acres and is developed with 11 wells. Cumulative production to Jan. 1, 1965, is 2,317,000 bbl of oil and 20,375 MMcf of gas. The reservoir pressure has decreased from an original value of 5,070 to 700 psia. The reservoir is now 90 per cent depleted.

The principal factors of comparison are recovery and GOR. The volatile-oil material balance prediction is within 10 per cent of actual performance, while the recovery predicted by the conventional material balance method is only 37 per cent of actual recovery. The greater accuracy of the volatile-oil material balance is due to the consideration of oil recovered from the gas phase. Performance of a volatile-oil reservoir can be predicted with a high degree of accuracy using the volatile-oil method.

Introduction

Jacoby and Berry described a method to improve performance predictions of a volatile-oil reservoir and specifically discussed a field in North Louisiana which produces from the Smackover lime.[1] The purpose of our paper is to compare the actual performance of this field with performance predicted using the volatile-oil method described by Jacoby and Berry and with the conventional Schilthuis-type[2] material balance prediction.

Geology

The producing reservoir under study is an anticlinal structure lying north of an east-west trending fault. The fault forms the south limit of the field. The remaining limits of the reservoir are controlled by a water-oil contact at −10,267 ft and by pinch-out of porosity and permeability development. The 10,000-ft reservoir is of the Mesozoic Era, Upper Jurassic system and is commonly called the Smackover lime.

The matrix material of the Smackover lime is a hard, dense limestone with porosity and permeability development resulting from oolitic deposition. The formation grades into a dense limestone lacking porosity and permeability where oolitic deposition is scarce.

All wells in the field were cored. Porosities in the individual wells varied from 9.8 to 20 per cent (average 13.6 per cent) with permeabilities varying from 20 to 1,019 md (average 174 md). Net pay was based on a minimum porosity of 5 per cent and a minimum permeability of 1 md as indicated by core analysis data. Average water saturation based on capillary pressure tests is 28.29 per cent.

Fig. 1 is an isopach of the net oil pay, which in the individual well is composed of several porous and permeable lime stringers. Pressure and production data indicate that the individual stringers in the 11 wells within the zero line of the isopach were in communication either through wellbores or vertical fractures. The seven wells to the north and west of the common reservoir shown are also completed in the Smackover lime; however, performance history indicates they are not in communication with the main 11-well reservoir. The 11-well reservoir will hereafter be designated the Main Reservoir.

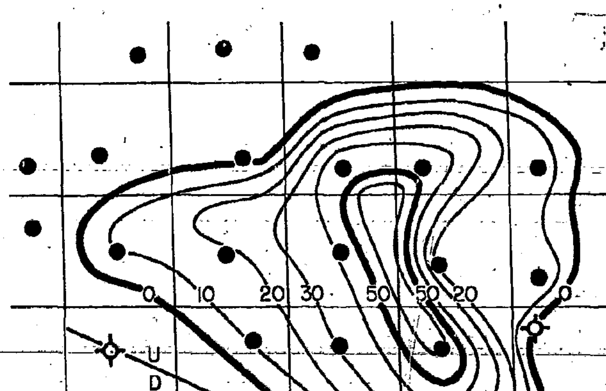

Fig. 1—Main reservoir isopach map.

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[1]References given at end of paper.

The Main Reservoir covers a 1,568-acre area, has an average pay section of 24.4 ft and contains 38,000 acre-ft.

Development and Production

The field was discovered in late 1953 and was completely developed with 11 wells on 160-acre spacing by Aug., 1956. The major portion of the development occurred in 1955.

Fig. 2 presents the production history of the Main Reservoir. Production began in Dec., 1953, at the rate of 250 BOPD and reached its peak of 1,130 BOPD in 1956. The abnormal decrease to 600 BOPD in 1957 was due to production restrictions imposed by the Louisiana Dept. of Conservation while casinghead gas connections for all wells were made. On Jan. 1, 1965, cumulative oil production from the Main Reservoir was 2,317,000 bbl and cumulative gas was 20,375 MMcf. This equals a recovery of 69 bbl oil and 532 Mcf gas per acre-foot of pay.

Reservoir Fluid Characteristics

Laboratory analysis of a bottom-hole fluid sample indicates the Main Reservoir hydrocarbons occured as a slightly undersaturated liquid near the critical point at initial reservoir conditions of 5,070 psia pressure and 246F temperature. The bubble-point pressure was 4,836 psia at reservoir temperature. The original producing gas-oil ratio was 2,000 cu ft/bbl. The reservoir volume factor by differential vaporization (conventional) was 4.7 as compared to 2.63 by separator flash calculations for bubble-point oil. The reservoir gas phase contains a relatively large amount of hydrocarbons recoverable as stock-tank oil due to the high temperature and fluid mixture composition itself. The conventional or black-oil differential vaporization analysis does not consider the hydrocarbon recovered from the gas phase, while separator flash calculations account for this recovery. This explains the variation in reservoir volume factors determined by the two methods. Complete bottom-hole sample analysis data are contained in Ref. 1.

Initial Oil in Place

Productive acre-feet based on the isopach map shown as Fig. 1 are 38,300 in the Main Reservoir. Stock-tank oil in place per acre-foot was computed to be 287 bbl based on average reservoir rock characteristics. Using these factors, the original stock-tank oil in place was 10,992,000 bbl. This corresponds to a figure of 9,135,000 bbl of stock-tank oil in place indicated by the volatile-oil material balance. The material balance oil-in-place calculation was made at a reservoir pressure of 3,957 psia (measured), at which time cumulative recovery was 937,000 bbl. The volatile-oil material balance calculations indicated a recovery of 10.26 per cent of the oil in place down to a reservoir pressure of 3,957 psia.

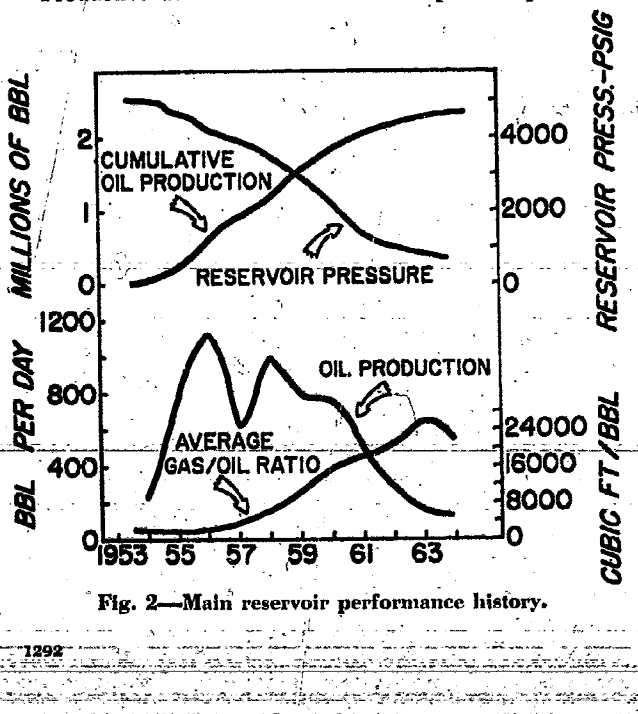

Fig. 2—Main reservoir performance history.

Early in the life of the Main Reservoir, when recovery ranged from 15 to 30 per cent of ultimate, volatile-oil material balance calculations indicated oil in place ranging from 7 to 9 million bbl. Calculations made above a recovery of 40 per cent of ultimate have consistently indicated oil in place of 10 to 12 million bbl.

The gradually increasing oil in place figures during early reservoir life could have been indicative of the presence of a partial water drive or gas-cap expansion. However, with the normal pressure depletion history indicated by Fig. 2, neither of these mechanisms appears to have been active. Apparently, the 48-hour shut-in bottom-hole pressure tests taken did not provide a true static reservoir pressure during the earlier life of the reservoir.

With the relatively large number of porous and permeable stringers with varying permeability forming the Main Reservoir, and with more than one stringer common to a particular wellbore, crossflow or equalization of pressure could have been occurring at the time the bottom-hole pressure test was obtained. As the individual stringers approached depletion, the severity of the pressure equalization problem diminished. This would account for the slightly lower indicated oil-in-place figures based on volatile-oil material balance earlier in the field life. Since the later material balance calculations consistently indicate an oil-in-place volume of 10 to 12 million bbl, it is believed that the pore volume estimate of 10,992,000 bbl of oil in place is accurate.

Reservoir Performance

Oil Production vs Pressure

Fig. 3 is a series of curves representing actual and predicted cumulative oil production vs bottom-hole pressure. Conventional material balance predicted an ultimate oil recovery of 880,000 bbl, or 8 per cent of the original oil in place to a depletion pressure of 500 psig, with a very severe pressure decline history after 50 per cent recovery of ultimate oil production. This calculation gives no credit to oil recovery from the gas phase.

The volatile-oil material balance predicted an ultimate oil recovery of 2.2 million bbl, or 20 per cent of the original oil in place with a gradually decreasing reservoir pressure. These calculations considered recovery resulting from liquid condensation out of the gas phase during production to the surface. The volatile-oil material balance calculations were based on separator conditions of 500 psia and 65F and stock-tank conditions of 14.7 psia and 70F.

Actual field production and pressure history have closely followed trends predicted by the volatile-oil material balance. Extrapolation of the actual production pressure curve indicates an ultimate oil recovery of 2.4 million bbl or 22 per cent of the original oil in place to a depletion pressure of 500 psia.

Actual ultimate oil recovery from the Main Reservoir will be 10 per cent greater than predicted by the volatile-

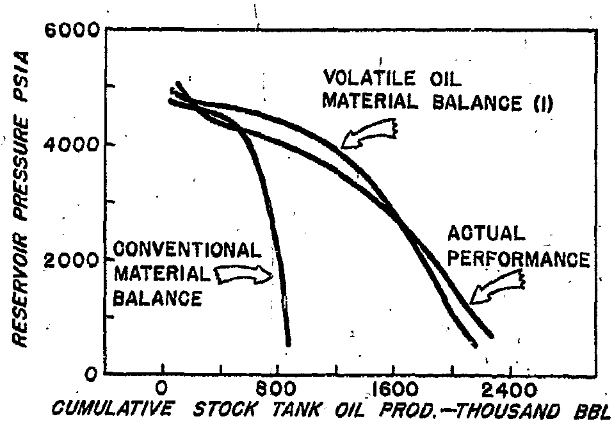

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Fig. 3—Main reservoir cumulative oil production vs reservoir pressure.

oil material balance method and 175 per cent greater than indicated by the conventional material balance calculation. The large error resulting from use of conventional material balance clearly illustrates the need to consider the varying reservoir fluid and well stream compositions as used by the volatile-oil material balance method.

Oil Production vs Gas-Oil Ratio

Fig. 4 is a series of curves showing actual and predicted cumulative oil production vs gas-oil ratios. Conventional material balance indicated a rapidly increasing gas-oil ratio, which peaked at better than 170,000 cu ft/bbl. The volatile-oil material balance predicted a gradually increasing gas-oil ratio, which peaked at 32,000 cu ft/bbl. Actual performance closely followed the trend predicted by the volatile-oil method, reaching an ultimate gas-oil ratio of 29,000 cu ft/bbl. The variation between the volatile-oil material-balance predictions and actual performance in the latter stages of reservoir life are the result of numerous changes in surface separator conditions. During this period, 3 three-stage casinghead gas compressors were installed. As wellhead pressure dropped below gas sales-line pressures, the wells were connected to the third-stage compression. As pressure further decreased, wells were connected to the second stage, and eventually to the first stage with separator conditions changing with each stage connection.

The gas-oil ratio predictions resulting from the volatile-oil material balance calculation are of great value in designing a casing-head gas gathering and compression system. Had the system design been based on conventional material balance predictions, a greatly oversized system would have been installed resulting in unnecessary expenditures.

Oil Gravity Performance

The volatile-oil calculations indicate that the API gravity of the oil produced from the Main Reservoir would gradually increase from original 51.2° API at 5,070 psia to 58.8° API at 750 psia. These predictions were based on stock-tank conditions of 14.7 psia and 70F. Actual gravity of produced oil increased from original to 63° API at 750 psia. Under actual field operations, stock-tank conditions varied considerably from conditions on which predictions were based with back-pressure held on the stock tanks at all times.

Conclusion

The volatile-oil material balance prediction method which considers oil recovery from the gas phase gives

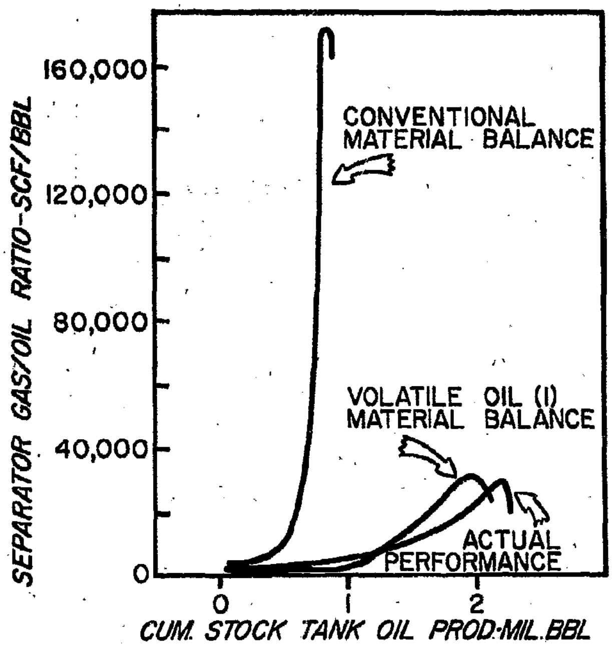

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Fig. 4—Main reservoir cumulative oil production vs gas-oil ratio.

results which are within acceptable limits for predicting performance of a volatile-oil reservoir. Conversely, the conventional material balance results in poor performance predictions when applied to volatile-oil reservoirs.

Acknowledgment

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2. Schilthuis, R. J.: "Active Oil and Reservoir Energy", *Trans.*, AIME (1936) **118**, 33. ★★★

J. C. CORDELL *(right) is a petroleum engineer with the Continental Illinois National Bank of Chicago. Prior to his present position, he was associated with Humble Oil & Refining Co. (1942-43) and Pan American Petroleum Corp. (1947-65). He holds BS and MS degrees, respectively, from Kansas and Texas universities.* C. K. EBERT *(left) joined Pan American Petroleum in 1954 as an engineering trainee at Duncan, Okla. He has held numerous petroleum engineering positions in Kansas, Mississippi and Louisiana. Since June, 1965, he has been with Pan American's Louisiana Gulf Coast Div. at New Orleans. Ebert graduated from Wisconsin Institute of Technology in 1954 with a BS degree in mining engineering.*