INTRODUCTION

The basic objective of this study was to evaluate the relative oil recovery potential of the Sadlerochit Reservoir at Prudhoe Bay under a number of different operating conditions.

The reservoir was modeled in cross section, using a six-layered, two-dimensional, three-phase mathemetical fluid-flow simulator. This work was preceded by a published volumetric study[1] and other independent, confidential studies[2] based on proprietary information which were designed to develop the best basic data with which to describe initial reservoir geometry, volume, fluid and energy conditions. During December 1975, a preliminary summary of this study was issued. Since that time, five additional cases have been studied, and are reported as Run Nos. 25 through 29. Contents of the December 1975 preliminary report have been updated and corrected. It should be recognized that the preliminary report is superceded by the present report.

BOUNDARY CONDITIONS

General boundary conditions were established such that the following basic cases could be evaluated and compared:

1. Depletion drive with gas cap expansion and 92% gas reinjection (8% for field use) into the gas cap from the start of producing operations--no aquifer.

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[1] "In-Place Volumetric Determination of Reservoir Fluids, Sadlerochit Formation, Prudhoe Bay Field," State of Alaska, Department of Natural Resources, Division of Oil and Gas, June, 1974, H. K. van Poollen and Associates, Inc.

[2] Studies prepared by H. K. van Poollen and Associates, Inc., for the Department of Natural Resources, State of Alaska.

2. Depletion drive with gas cap expansion and 92% gas reinjection, supplemented by a moderate-sized aquifer.
3. Depletion drive with gas cap expansion, 92% gas reinjection, and a moderate-sized aquifer supplemented by water injection beginning 4.75 years after the start of production. Water injection rate was set at 125% of the maximum oil-producing rate.
4. All of the preceding cases were also considered with gas cap sales of 2 MMMSCF/D, and some cases with 3 MMMSCF/D, and 4 MMMSCF/D, beginning 2.75 years after the start of production. All gas sales rates were net after 12% removal to account for CO_2 content, and 100 MMSCF/D assumed for fuel consumption.
5. Ten special cases, all with aquifer, water injection and gas cap sales, where certain operating limits were changed:
   a. Five well groups were recompleted and GOR limits increased to 25,000 SCF/STB on all wells after 13 years (GOR limit otherwise was 15,000 SCF/STB and WOR limit was 3 STB/STB for all cases).
   b. Two more well groups were added near the gas-oil contact after 14.75 years to control the potential loss of oil into the gas cap.
6. Five of the above special cases had gas sales delayed until 6.75 years.
7. A range of maximum sustained oil-producing rates of 1.2 MMSTB/D, 1.6 MMSTB/D and 1.8 MMSTB/D was set for most of the preceding cases. All runs were scheduled to produce at 0.6 MMSTB/D for the first 3 months, 1.4 MMSTB/D for the next 12 months, and then at one of the above maximum rates until the start of decline.

A total of 29 cases were run and their results are summarized in Table I.

SUMMARY

Listed in Table I are comparable numbers for each of the 29 cases run where the end-point field-producing rate reaches 100,000 STB of oil/day. (Run No. 24, with net gas sales of 4.0 MMMSCF/D after 2.75 years was terminated after 20 years because pressure became low in the gas cap. Oil rate after 20 years was 123,000 STB/D.) Figure 1 illustrates graphically the relative magnitude of oil recovery for each case listed in Table I. Detailed yearly results of each run are listed in Tables II through XXX, with all numbers taken at year end. Figures 19 through 47 show oil, net gas and water production rate, and cumulative production for each phase versus time. Figures 48 through 76 show oil rate, water injection, GOR, WOR and oil zone pressure versus percent oil recovery. Basic conditions and results of each run are further described in Appendix A.

A summary analysis follows:

1. Oil recoveries at an end-point field-producing rate of 100 MSTB/D range from a low 6.05 MMMSTB to a high of 8.18 MMMSTB. These recoveries are equivalent to 31.6% and 42.8% of original stock tank oil in place (Run Nos. 24 and 10).
2. The highest oil recoveries were obtained under conditions of an aquifer supplemented by water injection and no gas sales (92% reinjected with the balance for field use). Recoveries ranged from 7.70 MMMSTB (at a maximum sustained oil rate of 1.8 MMSTB/D) to 8.18 MMMSTB (at a maximum sustained oil rate of 1.2 MMSTB/D). These recoveries were obtained after 17.25 years to 25.0 years (Run Nos. 10, 11 and 12).
3. These higher ranges of oil recoveries can be approached under conditions of 2.0 MMMSCF/D gas sales and water injection if certain operating

limits are changed (as in Boundary Conditions, point 5). This is true at the higher oil-producing rates of 1.6 MMSTB/D, and 1.8 MMSTB/D, where recoveries were 7.84 MMMSTB and 7.80 MMMSTB after 27.5 years and 26.25 years, respectively (Run Nos. 21 and 22).

4. Increasing gas sales above 2 MMMSCF/D for a given maximum sustained oil rate (1.6 MMSTB/D) resulted in successively reduced oil recoveries. This is true for all cases compared, as shown in Fig. 2.

5. Delaying gas sales from 2.75 years to 6.75 years had very little effect on oil recovery in the higher oil rate cases (1.6 MMSTB/D and 1.8 MMSTB/D), when the gas sales rate was 2.0 MMMSCF/D (Run Nos. 21, 22, 26 and 27). In the case of lower oil rates or higher gas sales rates, however, delay of gas sales resulted in improved oil recoveries.
   a. With gas sales of 2.0 MMMSCF/D and maximum oil rate of 1.2 MMSTB/D, oil recovery was increased from 7.35 MMMSTB to 7.85 MMMSTB, or by 6.8% (Run Nos. 20 and 25).
   b. With gas sales of 3.0 MMMSCF/D and maximum oil rate of 1.6 MMSTB/D, oil recovery was increased from 7.02 MMMSTB to 7.45 MMMSTB, or by 6.1% (Run Nos. 23 and 28).
   c. With gas sales of 4.0 MMMSCF/D and maximum oil rate of 1.6 MMSTB/D, oil recovery was increased from 6.05 MMMSTB to 7.06 MMMSTB, or by 16.0% (Run Nos. 24 and 29).

6. The lowest recoveries resulted under a combination of depletion gas cap expansion drive (no aquifer or water injection) and partial gas sales. Recoveries in this category ranged from 6.10 MMMSTB to 6.44 MMMSTB, produced within 18.25 to 19.75 years (Run Nos. 4, 5 and 6).

7. Recovery is essentially independent of oil-producing rate (within the range of 1.2 MMSTB/D to 1.8 MMSTB/D) under conditions of no gas sales and no water injection, either with or without an aquifer (Run Nos. 1, 2, 3, 7, 8 and 9).

8. Gas recoveries ranged up to 30.182 MMMMSCF or 72.33% of original total gas in place. This was for the highest gas sales rate case of 4.0 MMMSCF/D after 2.75 years (Run No. 24).

QUALIFICATIONS

The numbers in this report should be considered relative rather than absolute. Reservoir performance predictions on a field without production history are approximate at best. Absolute values should be used with caution, but relative values can be used to compare production schedules with confidence.

The final recoveries of both oil and gas are influenced by the operational conditions assumed and the data input to the model. The model data was based on volumetric studies,[1] independent aquifer response,[2] gas coning,[2] gravity drainage studies,[2] and residual oil saturations from cores. Separate sensitivity studies[2] show that aquifer response will probably be moderate to non-existent. Early production and pressure history should be monitored carefully to determine the effectiveness of a water drive.

Coning studies[2] have shown that early gas breakthrough could occur. However, the extent of impermeable barriers, production rate, and distance of perforations from the gas-oil contact greatly affects this behavior.

The results of the present study are designed to show the overall effect of fluid withdrawals on gross reservoir behavior. Detailed results based on the available data would be presumptuous in the absence of some production history.

Recovery of liquids from the gas cap was not considered in the model predictions. While the inclusion of gas cap liquids would provide a relative improvement to total liquid recoveries in the gas sales cases, this improvement would not be of sufficient magnitude to change the basic

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[1] Ibid, p. 1.

[2] Ibid, p. 1.