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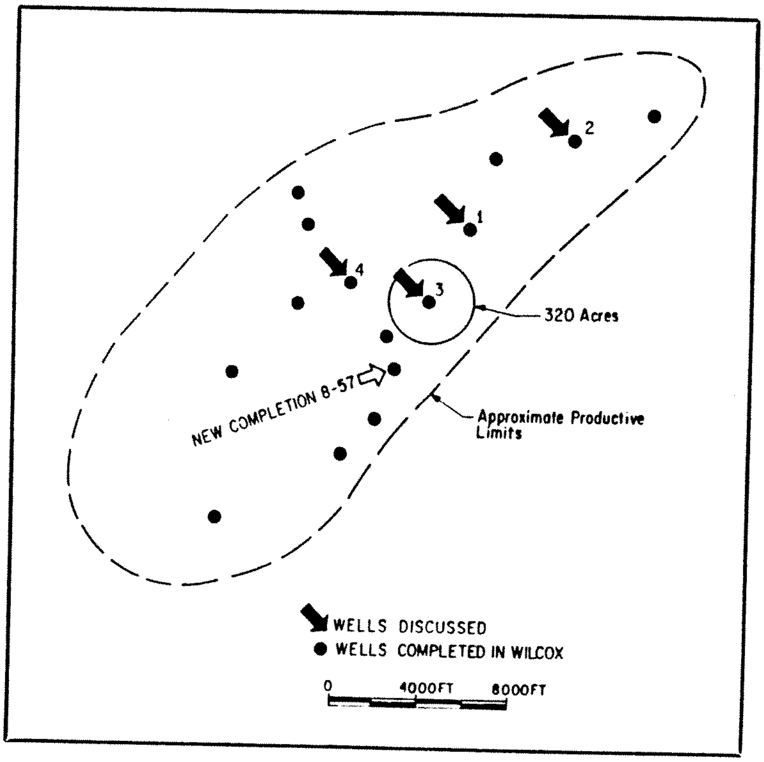

Fig. 1. Gas reservoir has several wells completed in the Wilcox (Eocene) sandstone. Bottomhole-pressure history of the reservoir is typical of depletion-type reservoirs, but several wells have shown radical but reasonable departures from established trends.

Evaluation of Individual Gas Well Reserves

by P. R. Stewart,
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The material balance approach is usually used to estimate reserves of a gas reservoir as a whole. However, recoverable gas from individual wells can be evaluated in the same manner provided semi-steady state conditions exist, i.e., if each well's drainage volume remains constant.

Indiscriminate application of this technique on an individual well basis can, however, lead to considerable error in the estimation of gas reserves since production rates change with time because of mechanical problems, well productivity, proration effects and additional completions within the reservoir. This field study proves the theory derived by Matthews et al[1] that at steady state each well's drainage volume is proportional to its production rate. The theory was further developed to demonstrate that the average pressure in an entire bounded reservoir can be determined by the volumetric average of drainage volume pressures. Results of this study show that this theory may be used with confidence.

This report presents a striking example of the application of the material balance to a large depletion-type, gas-condensate reservoir in South Texas in which the indicated drainage volume and ultimate gas recovery of individual wells were affected by changes in well productivity and additional development.

Gas-Well Material Balance

The accepted method of reserve determination for a volumetric (depletion-type) gas reservoir is the application of the principle of conservation of mass in the standard material balance:

$$G_i = Q_t \frac{(P_i/Z_i)}{P_i/Z_i - P_t/Z_t}$$

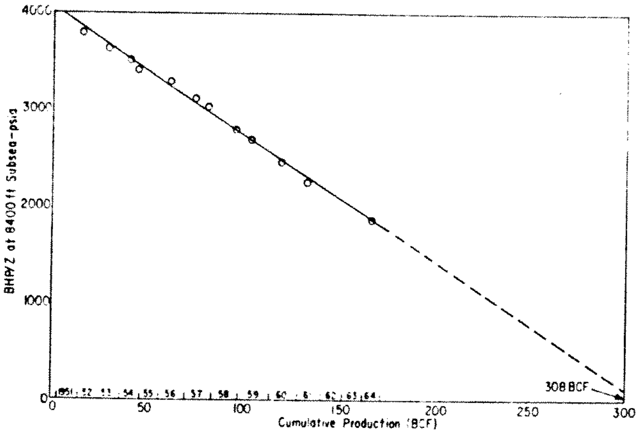

Fig. 2. Reservoir decline curve shows conventional behavior of the field and gives a volumetric estimate of in-place gas at 308 Bcf.

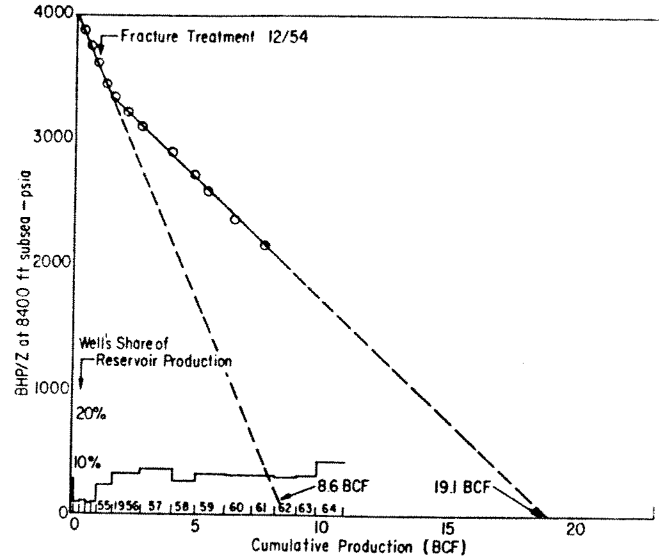

Fig. 3. Well No. 1 was fractured in Dec. 1954 and experienced a great increase in productivity. Previously indicating gas in place at 8.6 Bcf, the well now appears to be draining a reservoir volume of 19.1 Bcf.

The solution of this equation at any time, t, and cumulative gas production, Q_t, will result in a single value for original gas in place, G_i. Values for G_i derived from calculations at different times may be averaged to determine an average value of the original gas in place.

A more convenient expression of the material balance performance of volumetric gas reservoirs is:

$$P_t/Z_t = P_i/Z_i - CQ_t, \text{ where } C = \frac{(P_i/Z_i)}{G_i}$$

As indicated by the equation, a graph on coordinate paper of BHP/Z vs cumulative gas production will yield a linear plot. Extrapolation of a best fitting straight line to a zero value of P_t/Z_t will determine the gas-in-place in the reservoir. Recoverable gas would be some fraction of this amount as dictated by the abandonment pressure.

General Description

The subject gas reservoir produces from a Wilcox (Eocene) sandstone at an average depth of 8650 ft (8475 ft subsea) (Fig. 1). Entrapment of the gas is the result of typical Wilcox en-echelon, down-to-the-coast faulting with anticlinal folds between the major faults. The reservoir is within the largest NE-SW trending anticlinal fold of the complex.

The reservoir has some 7500 productive acres and 260,000 net acre-ft with gas production from six sand members, most of which are normally open to production in each well. The average air permeability of these sands ranges from 8.5 md to 50.7 md with a weighted average of 36 md. Average porosity is 18% and initial water saturation is estimated at 25%. Utilizing these two parameters and the productive volume, the volumetric estimate of in-place gas is 310 Bcf. This is in excellent agreement with the material balance estimate of 308 Bcf shown in Fig. 2.

Full-scale gas sales from the reservoir began in January 1951 and cumulative gas production through December 1965 was 180 Bcf, giving an average daily gas production for the reservoir of over 33 MMcf. Initially, the reservoir was developed with 13 producing wells; subsequently, in 1957-58, two additional producers were completed. Based upon an abandonment BHP/Z of 750 psia, ultimate recovery from the reservoir should be some 250 Bcf wet gas. The reservoir, then, is currently some 72% depleted and reservoir material balance analysis should be quite valid at this time.

Although the bottomhole pressure history of the reservoir shows a good linear decline with cumulative production expected from a depletion-type gas reservoir, several of the wells have exhibited radical departures from previously established trends in BHP/Z vs cumulative production. Therefore, the following analyses of individual well performance present some exam-

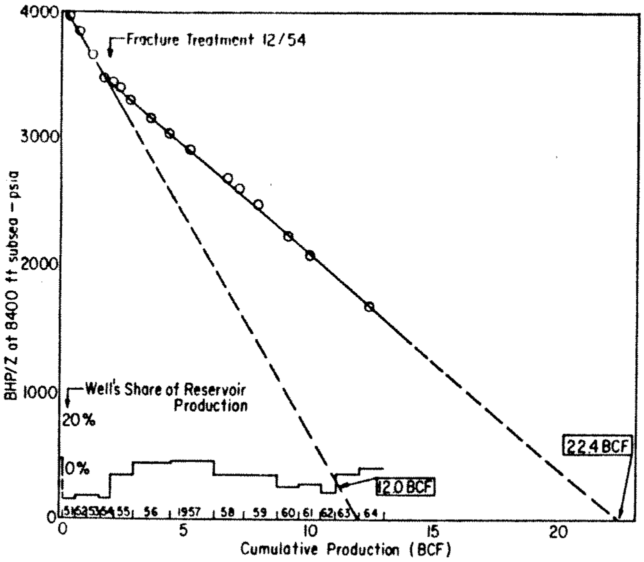

Fig. 4. A fracture treatment of Well No. 2 increased the drainage volume from 12.0 Bcf to 22.4 Bcf. Well's share of reservoir production increased likewise from 4.2% to 8.8%.

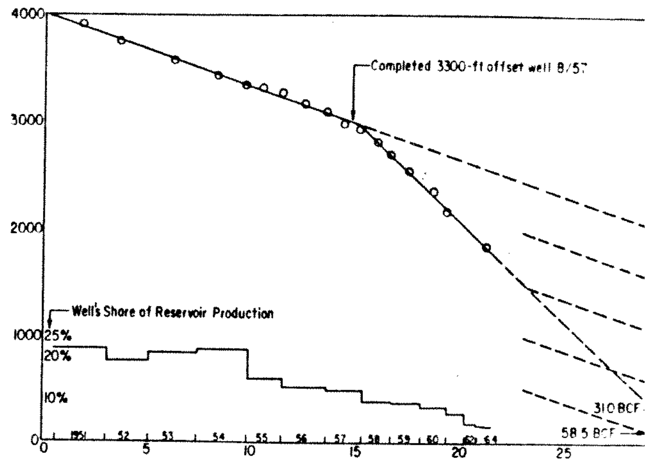

Fig 5. The effect of drilling an offset well was quickly and dramatically reflected in Well No. 3, reducing drainage volume from 58.5 Bcf to 31.0 Bcf.

ples of changes in drainage volumes (and thus ultimate recoveries) that may occur during an individual well's productive life.

Increased Drainage Volume

Well No. 1. This well currently has a cumulative gas production of 11 Bcf and an indicated gas-in-place of 19.1 Bcf (see Fig. 3). However, prior to a fracture treatment in 1954, the well was indicated to be draining a reservoir volume of only 8.6 Bcf gas, and producing only 2.8% of the total reservoir's production. As a result of the fracture treatment, the well's productivity was greatly increased as indicated by the large increase in the permeability-thickness product (kh) (an evident opening of more productive section), and the well has consistently produced some 8% of the total reservoir production.

Well No. 2. Prior to a fracture treatment in 1954, this well (as shown in Fig. 4) was producing only 4.2% of the total reservoir's production, and had an indicated in-place-gas in its drainage area of 12.0 Bcf. As a result of the fracture treatment in which the high positive skin was removed, the well has been produced at an average rate of 8.8% of the total reservoir rate and is indicated to be draining from a reservoir volume encompassing 22.4 Bcf gas.

Decreased Drainage Volume

Well No. 3. This well was initially produced at the highest rate of any well in the reservoir (see Fig. 5) and was indicated to be draining from a reservoir volume of 58.5 Bcf gas, with an ultimate recovery of some 47 Bcf gas. Although the well's share of the reservoir's production was

Table 1. Production Rate and Drainage Volumes

Well	Initial Period: Gas In-Place, Bcf	Initial Period: Gas In-Place, % of Total Reservoir	Initial Period: Well's Share of Total Res. Prod.	Current Period: Remaining Gas In-Place, Bcf	Current Period: Remaining Gas In-Place, % of Total Reservoir	Current Period: Well's Share of Total Res. Prod.
Well No. 1	8.6	2.8%	3.0%	17.6	7.0%	8.1%
Well No. 2	12.0	3.9%	4.2%	20.4	7.8%	8.8%
Well No. 3	58.5	19.0%	18.8%	16.0	7.0%	7.1%
Well No. 4	32.0	10.4%	9.1%	15.6	7.0%	6.4%
Well No. 5	—	—	—	22.0	9.6%	11.0%

*New well completed in August 1957.

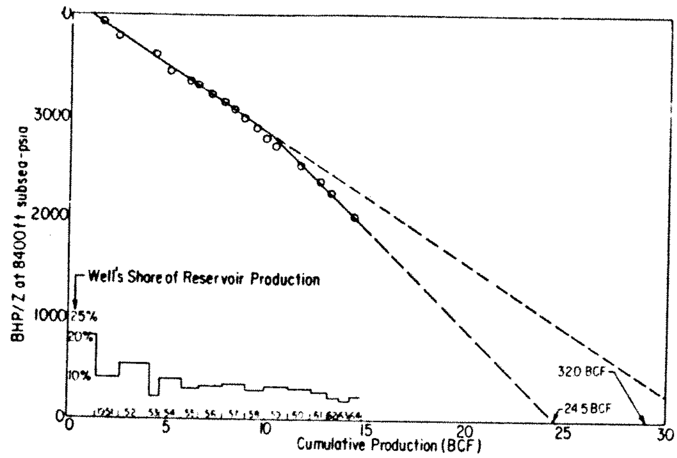

Fig. 6. Fairly gradual decline in the drainage volume of Well No. 4 with no change in producing rate probably reflects the overall improvement of other wells producing from the reservoir.

About the Author

P. R. Stewart is a reservoir engineer for Shell Oil Co. in Denver, Colo. He was graduated from the North Carolina State University with a BS degree in geological engineering. Following work in oilfields of Louisiana and New Mexico and earning an MS degree in petroleum engineering from the University of Illinois, he joined Shell Oil Co. in 1960 as an exploitation engineer. He was subsequently assigned as a reservoir engineer to the Texas Gulf Coast area before being transferred to Shell's Rocky Mountain Division in 1965.

decreased by some 30% in 1955 due to better productivity of other wells from fracture treatments, the drainage volume for the well apparently remained unchanged until 1957 when a 3300-ft offset well was completed in the reservoir. Shortly after this new completion, interference in the drainage area of Well No. 3 became quite evident as indicated by acceleration in decline in the well's bottomhole pressure and the material balance plot of BHP/Z vs cumulative production now indicates an in-place gas of 31 Bcf for the well.

Well No. 4. No particular occurrence can be documented to explain the decline in drainage volume for this well (see Fig. 6) since no large sustained change in the well's producing rate has occurred, no new nearby wells were completed and no immediate offset well increased its production rate measurably. However, it would appear that the indicated change in ultimate recovery for the well is in response to an overall increased "competition" within the reservoir as a result of the higher production rate of the fracture treated wells, and a new completion within the reservoir.

Conclusions

The reservoir has performed as a depletion-type reservoir as demonstrated by the linear plot of P/Z vs cumulative production. Several wells in the reservoir, however, have shown some marked changes in the slope of the P/Z plots. In two instances, these changes resulted from increased well productivity due to fracture treatments. In two other instances the changes are due to new completions and increased production from other wells in the reservoir.

Table 1 summarizes the production rates and drainage performance of the wells previously discussed. The excellent agreement between individual well production rates and drainage volumes is readily apparent.

The preceding analysis and documentation of deviation from previously well established BHP/Z vs cumulative production trends should be quite enlightening to production and reservoir engineers working closely with material balance prediction of gas well recoveries. Although prior forecasts of per-well recoveries can be considerably in error, it is apparent that if a gas reservoir is sufficiently permeable and interconnected, the ultimate gas recovery from a well should be in direct relation to the well's production rate relative to the total reservoir production rate and field ultimate recovery.

Reference

[1]Matthews, C. S., et al, "Method for Determination of Average Pressure in a Bounded Reservoir," Trans AIME, Vol. 201, 1954, p. 182. ■