WATERFLOOD CASE HISTORY CAPROCK QUEEN FIELD

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INTRODUCTION

Waterflooding in the Caprock Queen Field began with a pilot waterflood initiated in 1956. Today, essentially the entire field is under waterflood. There are 13 different projects in operation; eleven are units while two are of the cooperative type. All 13 projects have utilized 80-acre five-spot patterns. This case history is presented in order to depict the general performance of 13 successful Queen Sand waterfloods, and should be helpful in predicting the performance of other waterfloods that may be initiated in similar reservoirs.

In many cases the enginer is forced to use experience factors or "rules of thumb" in order to predict the performance of a proposed waterflood. When adequate reservoir data is available he should, of course, make use of it in predicting performance. However, even after making calculations and the corresponding predictions, the engineer should attempt to compare his predictions with actual performance of other floods, either in operation or depleted, which are similar to the flood he is proposing. Quite often there are floods in the same field or in the same formation in a nearby field that are comparable to the proposed flood. A review of the performance of similar floods can be helpful, not only in designing the injection system and selecting a pattern, but also in making a reasonable prediction of the performance that can be expected.

The data used in preparing this case history was taken from reports published by the New Mexico Oil and Gas Engineering Committee.

LOCATION

The Caprock Queen Field is located in eastern Chaves County and western Lea County, New Mexico in Townships 12, 13, 14 and 15 South, Range 31 East and in Townships 12 and 13, Range 32 East. The field trends northeast to southwest along the Mescalero Escarpment. It is over 23 miles long and up to three miles wide. Location of the field is shown in Fig. 1, while the project outlines are shown in Fig. 2.

PRIMARY HISTORY

Primary development took place over a period of 17 years. The initial discovery was on the north edge of the field in Section 30, T-12-S, R-32-E in November 1940. The central portion of the field was discovered in June 1953 in Section 15, T-14-S, R-31-E. At that time the northern area consisted of some 120 wells and had declined drastically in producing rate as shown in Fig. 3, which is the field performance curve. By 1956, as a result of further discoveries and development in the central and south areas, the field consisted of over 500 wells. The producing rate in 1956, as indicated by Fig. 3, was near 450,000 bbl of oil per month.

Primary development resulted in the drilling of over 640 wells on 40-acre spacing. Some fringe drilling took place during secondary recovery operations. For the 28,000 developed acres we estimate the ultimate primary oil recovery at some 30 to 35 million bbl of oil. This estimate is based on decline curve analyses of the 13 injection projects, of which several were in an early or middle stage of primary depletion when injection was initiated and did not have well established decline trends.

AVERAGE RESERVOIR AND FLUID PROPERTIES

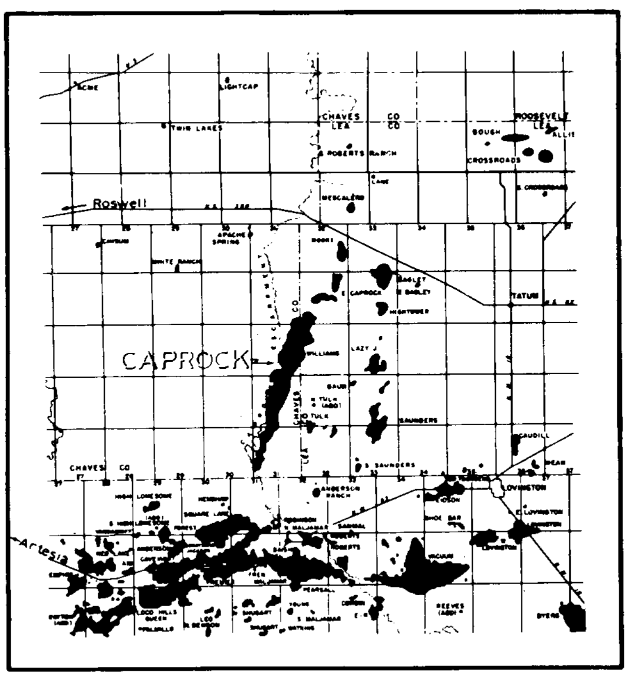
The Queen Sand, or "Red Sand" as it is called locally, is an upper member of the Queen formation of Permian Age. Average depth to the top of the pay is 3000 ft. The reservoir is a stratigraphic trap with some 50 ft of relief, and a regional easterly dip of 25 ft/mi. Oil production has been due to a solution gas drive, although there is an extensive gas cap along the western edge of the field offsetting the South Caprock Unit Boundary. An oil-water contact exists along the eastern edge of the field; however, no effective water drive has been reported.

Properties of the Queen Sand vary considerably over the field with the overall average properties reported to be: nine feet of net pay, 19 per cent porosity, 150 to 200 md permeability and 26 per cent water saturation. The initial solution gas-oil ratio, estimated at 260 SCF/B, was rather low and probably resulted in a relatively poor primary recovery, which no doubt enhanced the recovery by waterflooding.

WATERFLOOD PILOT

In 1950, an attempt at secondary recovery by air injection was initiated. Reports of this attempt indicate that failure was due to rapid breakthrough of the air at producers with relaitvely little gain in oil production.

A pilot water injection project was initiated in 1956 in the northern area by Graridge, Gulf and Great Western Drilling companies. This cooperative venture consisted of two 80-acre five-spot patterns. The injected water was obtained from shallow fresh water sands and needed no filtration. Injection rates of from 500 to 600 BWPD per well caused oil production response



LOCATION MAP OF
CAPROCK QUEEN FIELD
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Fig. 1

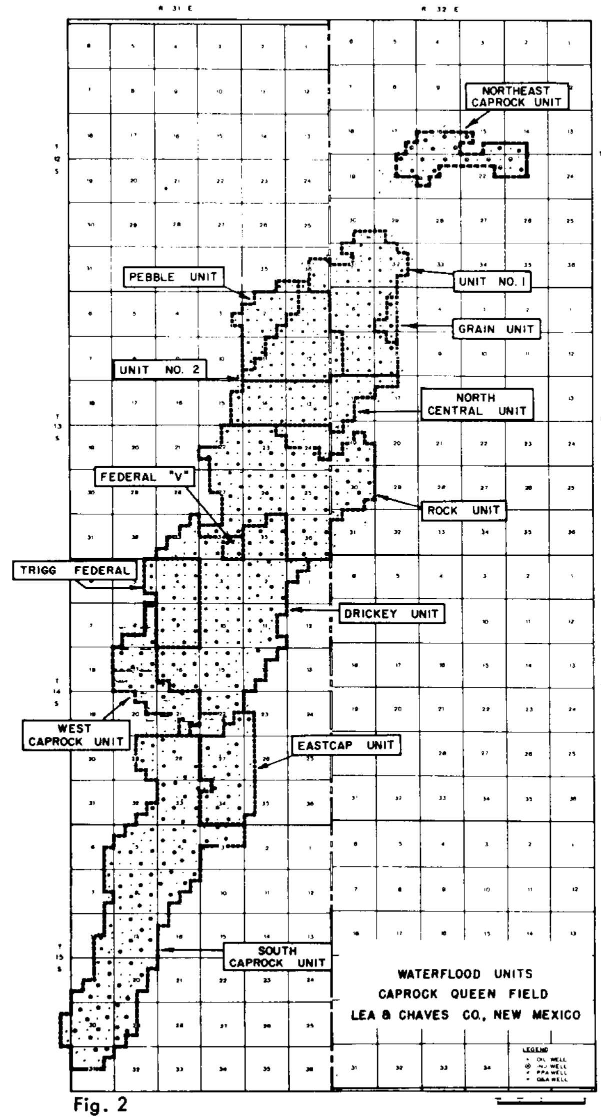


Fig. 2

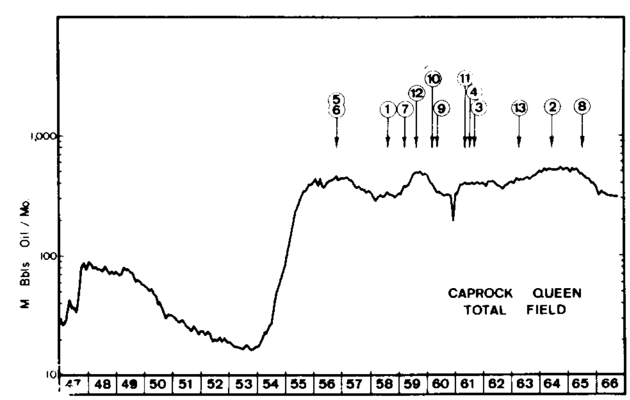


Fig. 3

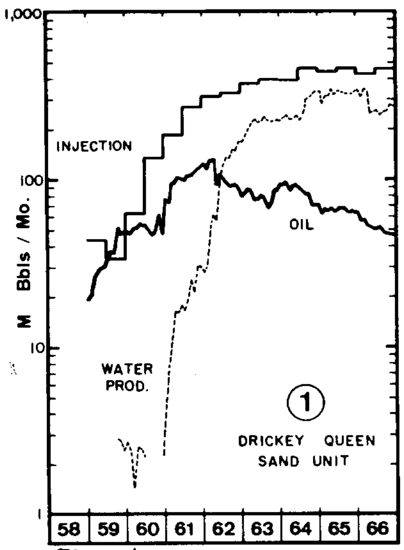
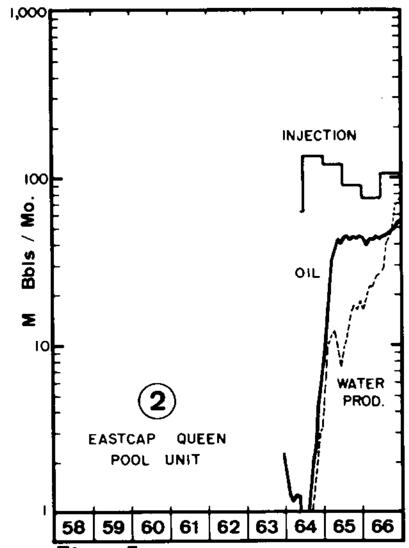


Fig. 4



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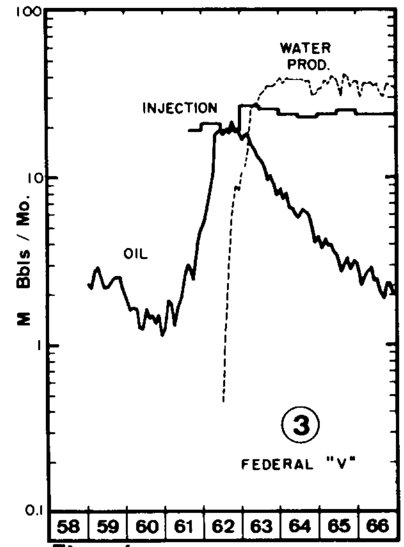

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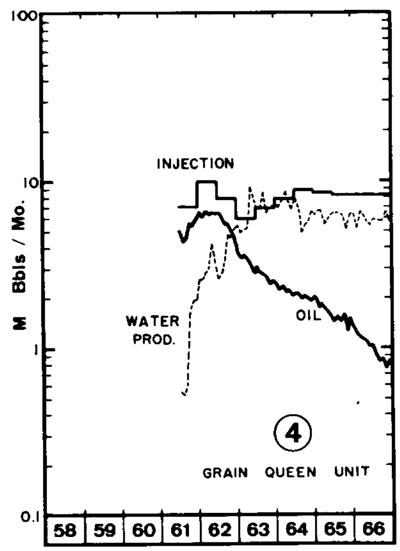
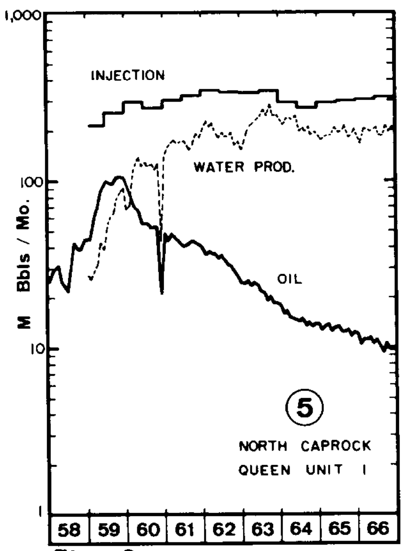


Fig. 7



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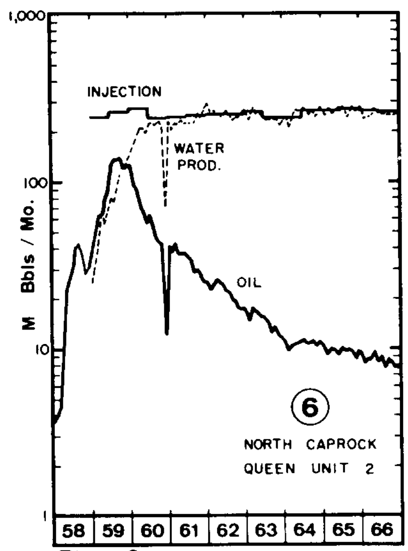


Fig. 9

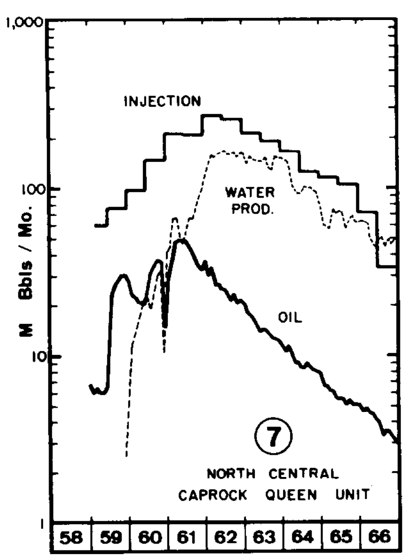


Fig. 10

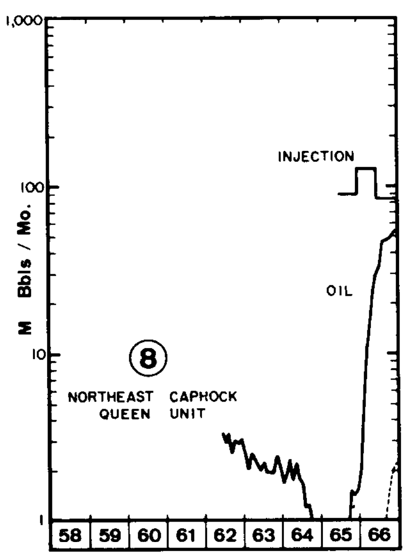
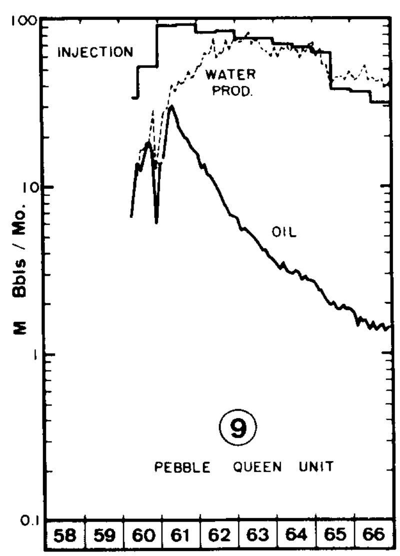


Fig. 11



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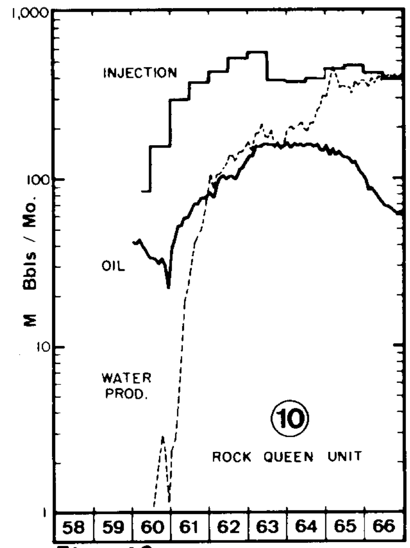

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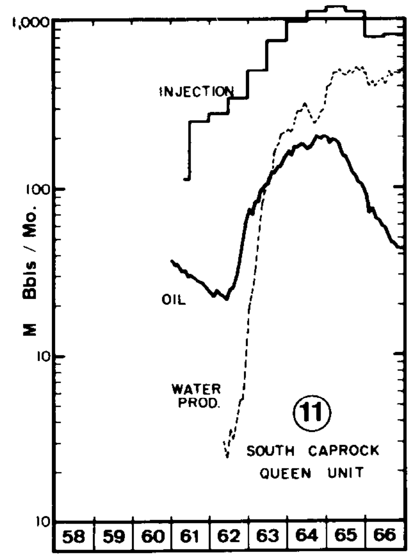

Fig. 14

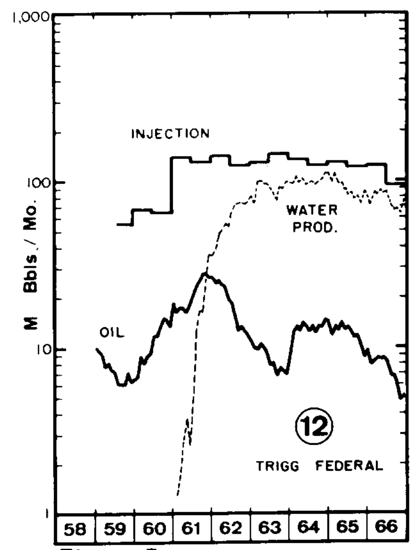

Fig. 15

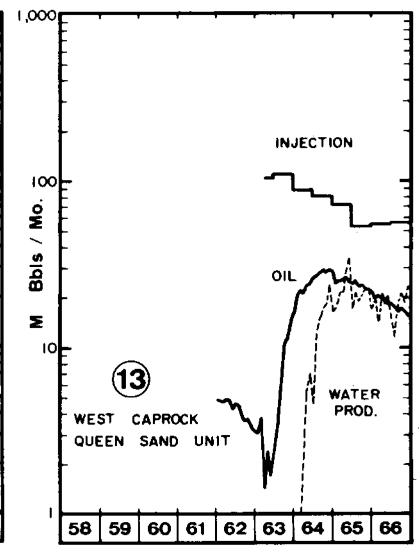

Fig. 16

in about seven months, which was reported to be about 80 per cent of fill-up calculations. The response varied in intensity at the nearby producers and indicated definite effectiveness of waterflooding on 80-acre five-spot patterns.

WATERFLOOD OPERATIONS

Soon after response, 2880 acres around the pilot were unitized as Unit No. 1. Unit No. 2, which also had a successful pilot project, was formed soon after. The third unit (North Central) was then formed, making a total of 6880 acres under unitized waterflood operation in 1959. The area encompassed by these units is shown in Fig. 2. During the time the first three units were being formed, Cities Service also initiated a pilot in the Drickey area which responded successfully and led to the forming of the Drickey Unit. Figure 3, which represents total field oil production, shows the time of initial water injection for each project. The circled numbers in Fig. 3 correspond with the circled numbers in Figs. 4 through 16, which are performance curves of the individual projects.

As a result of the indicated effectiveness of the early projects, the Oil Conservation Commission granted a capacity type allowable, where needed, to prevent loss of oil across lease lines. However, by 1959, the success of the Caprock waterfloods was interpreted by some to indicate that all fields would respond accordingly and that a great number of projects would be initiated over a short period of time, and thus possibly suppress exploratory drilling. The end result of this interpretation was the Commission's adopting Rule 701 to control the rate of development in and the producing rate of future injection projects. Of course, as Fig. 3 relates, even though the effectiveness of waterflooding was proven, it took a considerable period of time to form units and begin injection operations. This delay in forming units for waterflooding probably had more effect on the field oil production rate than did Rule 701.

Performance of individual projects is shown in Figs. 4 through 16. With a few exceptions the performance curves are similar and have a "text book" shape. In most cases 50 per cent water cut occurs shortly after peak oil rates. Projects such as 1, 10 and 11 are large projects and were developed in stages mostly due to Rule 701. In these cases, 50 per cent water cut precedes peak oil rates. Project 10 was placed on injection in an early stage of primary depletion causing a considerable amount of primary oil to be produced with waterflood oil. This flood operated at top allowable for two years. Projects 4 and 9 resulted from fringe drilling after waterflood development had taken place, offsetting the two areas, and appear to have been stimulated at the time of drilling.

As of January 1, 1967 the field had produced 60 million bbl of oil with an estimated 13 million bbl left to be produced. Deducting 30 to 35 million bbl of estimated ultimate primary oil recovery, waterflood oil recovery will be 38 to 43 million bbl. The ratio of secondary to primary recovery will average between 1.1 and 1.4 for the entire field.

RULE OF THUMB COMPARISONS

The application of other "rules of thumb" to these 13 projects, beside the fact that waterflood recovery is greater than primary recovery, also indicates waterflooding in the Caprock Queen Field has been highly successful. The ratio of injection rate to peak oil producing rate normally varies from 2 to 12 in successful floods. In the Caprock Queen this ratio varied from 1.9 to 5.5 for the 13 projects involved. The ratio was less than two in three small floods (projects 3, 4 and 9), which apparently received benefit from offset injection. The highest ratio (5.5) was for project 11 that has almost 50 per cent of its periphery bordering the gas cap. A ratio of 5.5 is considerably lower than would be expected under similar circumstances.

Another useful rule of thumb is the ratio of ultimate water injection requirements to secondary oil produced. Normally it takes approximately 10 bbl of injected water to produce one bbl of waterflood oil. For the three oldest full-scale waterfloods, which are now near depletion, this ratio varies from 7.7 to 8.4. These projects will probably be abandoned at a ratio of about 9 to 1. The difference between a ratio of 9 and 10 may seem insignificant but in the Caprock Queen Field this difference represents more than 40 million bbl of water injection.

ACKNOWLEDGMENT

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