2.3.4 Full-Field BOAST 3 Simulation

2.3.3.1 BOAST 3 Simulator :

Simulation studies for Schaben Field were carried out with BOAST 3 simulator. BOAST 3 is a public domain PC based reservoir simulation tool from the U.S. Department of Energy. BOAST 3 is black oil applied simulation tool that performs reservoir evaluation and can be used to design solutions to different petroleum engineering problems. BOAST 3 is an isothermal, 3D, three phase simulator that assumes reservoir fluids with constant composition and physical properties dependent solely on reservoir pressure. These reservoir fluid approximations are applicable for a large percentage of the world's oil and gas reservoirs. The BOAST 3 simulator has wide range of applicability and can be used to simulate the oil and gas recovery under different scenarios such as primary depletion, pressure maintenance by gas/water injection, evaluation of secondary operations by waterflooding operations.

BOAST 3 is a finite-difference implicit pressure/explicit saturation (IMPES) numerical simulator. The well model in BOAST 3 allows specification of rate or pressure constraints on well performance, and the user is free to add or recomplete wells during the coarse of the simulation. Multiple rock and PVT regions can be defined, and three aquifer models are available as options.

2.3.3.2 History Match and Prediction

The major premise of this simulation study was to enter eleven years of historical data and have the simulator predict and match the next 23 years of known field production data. The historical data entered into the simulator input file included the daily oil production rate for each well. Daily oil production rate at each well was obtained by dividing the cumulative oil produced by the well in a year by the number of days the well operated in that year. During the first eleven years, the simulator calculated the bottom hole flowing pressure at each well that was necessary to produce the given oil production rate, and then used this bottom hole pressure to calculate the water production at each well. As the simulator was able to predict the water production rates during the first eleven years within a reasonable degree of accuracy, the corresponding flowing bottom hole pressure at the end of eleven years were thought to be acceptable. The calculated bottom hole flowing pressure at each well at the end of the first eleven years was noted. During the prediction phase, only the flowing bottom hole pressure at each well was entered in the input file and the simulator calculated both the oil and water production rates. The flowing bottom hole pressure entered for each well during this prediction phase was based on the corresponding bottom hole flowing pressure calculated by the simulator at the end of the eleventh year. Production profiles show that the water-oil ratio at each well remains almost constant after eleven years. Thus it was assumed that the flowing bottom hole pressure at each well during the prediction phase was close to that calculated by the simulator at the end of the eleventh year. It was also assumed that as the well aged, the flowing bottom hole pressure at each well would decline.

The flowing bottom hole pressure at each well that was entered in the input file during the prediction phase was a percentage of the pressure calculated by the simulator at the end of the eleventh year. This percentage value varied from 100% to 85% (in a descending manner) over the period of prediction (i.e. from the thirteenth to the thirty-fourth year).

2.3.3.3 Simulation Results

At the field level, a good match between simulated and observed was obtained for both oil and water production rates during the 34 years encompassed by the historical and predictive periods (Figure 2.40). The only exceptions are two years (between 7300 to 8030 days). Field production records indicate that a large number of wells were shutin during this period for administrative and economic reasons. Due to certain technical problems faced during the construction of the input file for BOAST 3, individual wells could not be shut off or reactivated after the first eleven years. Thus the simulation is unable to match the daily field production rates during the anomalous period when many of producing wells were idled.

A good match was also obtained for the simulated and observed cumulative oil and water production for the field from 1963 to 1996 (Figure 2.41). After matches were obtained within acceptable tolerances for both oil and water at a field scale, attention was focused on the performance of the individual wells. Figures 2.42 and 2.43 show the match obtained for individual wells between the simulated cumulative oil and water production and the historical cumulative production. The ratio as defined in both plots is the ratio between observed cumulative production and predicted cumulative production for each well generated from the simulation. A ratio of 1 would indicate that simulated cumulative production is equal to the corresponding historical production. Most of the wells have a ratio between 0.9 to 1.1 indicating a good match of the cumulative oil production on a well to well basis (Figure 2.42). In case of water production the majority of the wells have a ratio varying between 0.8 to 1.2 (Figure 2.43). However, a number of wells have a ratio value as high as 10 and some as low as 0.1. The simulator appears to over and under predict the water in some wells.

The mismatch of water production in some of the wells may be due to inaccurate description of the reservoir properties around the concerned wells. Schaben field is a fractured reservoir with an active bottom water drive. The vertical permeability in the reservoir and more specially in the aquifer around the well plays a very important role in controlling the water production at the well. Several reruns were carried out on the simulator with the vertical permeabilities lowered around wells where the simulator over predicted water resulting in drastically reduced water production. Similarly, increasing the vertical permeability around the wells resulted in the increase of the simulated water production at the well. This process of local adjustment of the vertical permeability could be applied on every well to make the simulated results match more closely the historical production. Another important point to note is that the historical water production data may not be very accurate because it was derived from the oil production values and the corresponding water-oil ratios.

Oil saturation maps generated from the simulation output at different time periods of the field history show the oil saturation across the field at the beginning of 1963, the end of 1973 (i.e., at the beginning of the prediction phase), and at the end of 1996 (figures 2.44 and 2.45). The simulation indicates that by the end of 1973 areas of low oil saturation have started to develop around wells, especially wells with a high production rate (Figure 2.44). At the end of 1996 the simulation shows oil saturation dropping around most wells to just above the irreducible oil saturation (i.e., between 0.31-0.35). However, significant pockets of high oil saturations are left unswept in between the drainage areas of surrounding wells (Figure 2.45).

Using the simulation results a residual oil saturation-thickness map for Schaben field at the end of 1996 was generated (Figure 2.46). The relative permeability curves used in the simulation indicate an irreducible oil saturation of 0.25. If the relative permeability curves are correct, it will be difficult to produce oil from zones having an oil saturation that is approaching 0.30. A conservative oil saturation cut off of 0.40 along with a pay thickness cut off of greater than 20 feet was employed to construct a map showing areas with the highest predicted infill potential (Figure 2.47). All grid cells with a residual oil saturation less than 40% or with a net pay thickness less than 20 feet were zeroed.

Based on the infill potential map and in consultation with one of the operators of Schaben field, three sites were chosen to locate new wells. These sites are marked with a white circle on the map (Figure 2.47). Subsequent simulation runs were carried out with the three new wells coming on production in the simulator during the year 1996. The simulation with the three new wells was run through the year 2006 and an oil saturation map was generated from the simulation output (Figure 2.48). Predicted daily field production rate of oil and water after the three new wells has been put in operation indicates the addition of significant additional oil production (Figure 2.49). The three new wells were simulated to produce under a back pressure (i.e., a flowing bottom hole pressure) equal to that of the nearest well at the end of 1996. The daily production rate simulated for the Moore BCP #3 is calculated to produce a total of 47,200 bbls of oil and 227,600 bbls of water over a period of ten years (Figure 2.50). The simulator also predicts daily oil production above 10 bbls during the first 5 years.

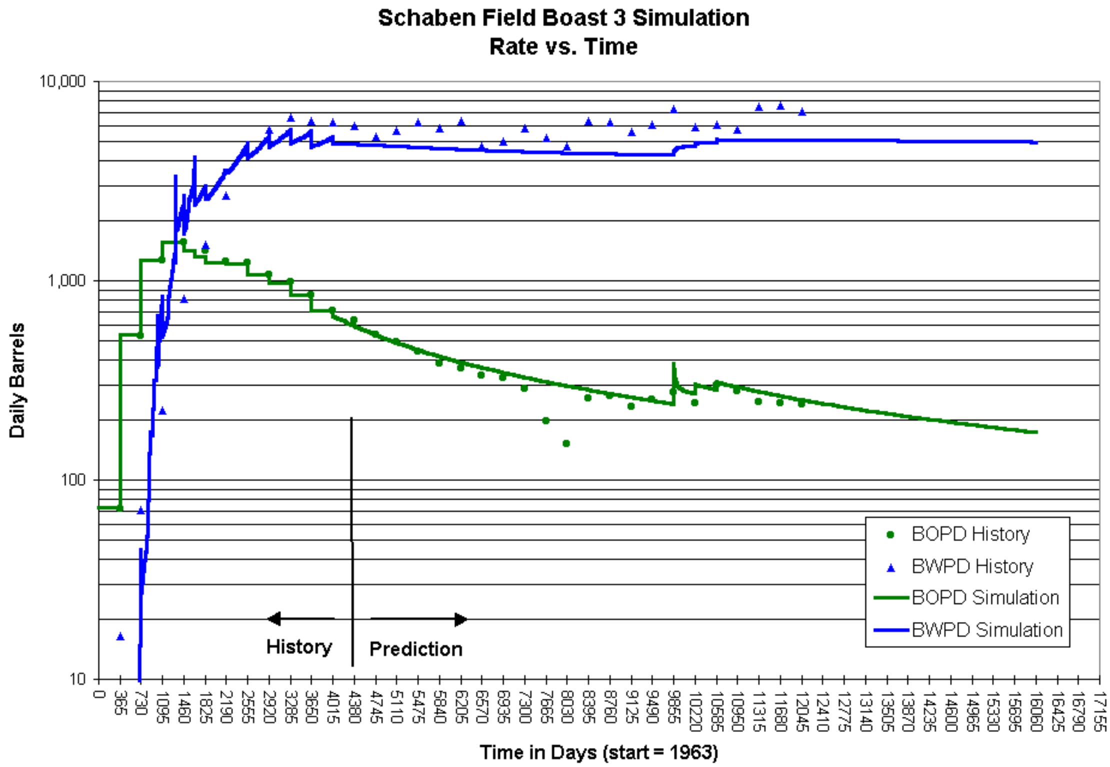
Schaben Field Boast 3 Simulation
Rate vs. Time
Daily Barrels
10,000
1,000
100
10
History
Prediction
BOPD History
BWPD History
BOPD Simulation
BWPD Simulation
Time in Days (start = 1963)

Figure 2.40

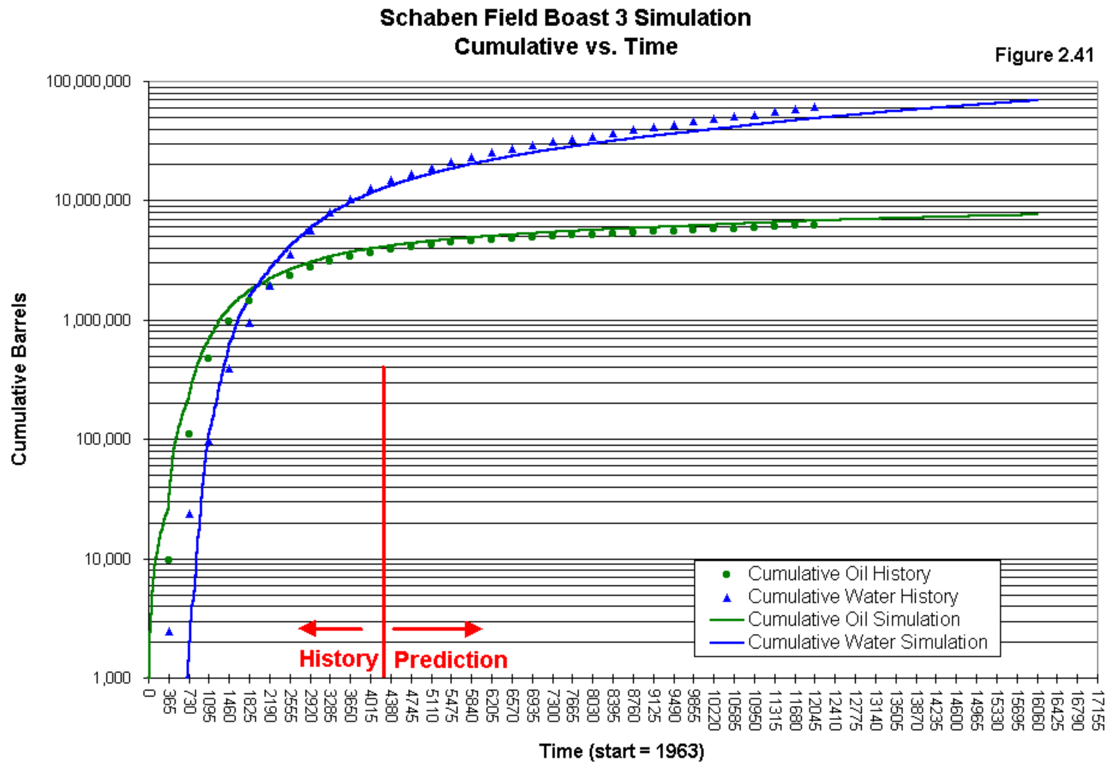
Schaben Field Boast 3 Simulation
Cumulative vs. Time
Figure 2.41
100,000,000
10,000,000
1,000,000
100,000
10,000
1,000
Cumulative Barrels
History
Prediction
Cumulative Oil History
Cumulative Water History
Cumulative Oil Simulation
Cumulative Water Simulation
Time (start = 1963)

Figure 2.41

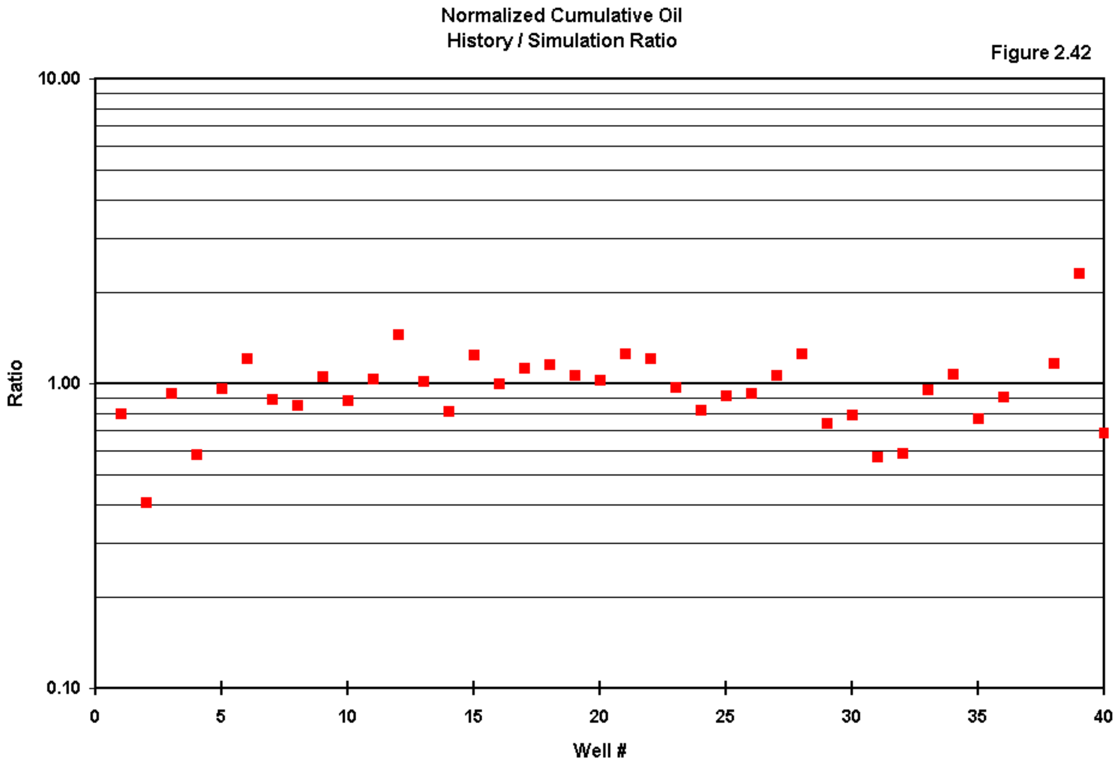
Normalized Cumulative Oil
History / Simulation Ratio
Figure 2.42
10.00
1.00
0.10
Ratio
0
5
10
15
20
25
30
35
40
Well #

Figure 2.42

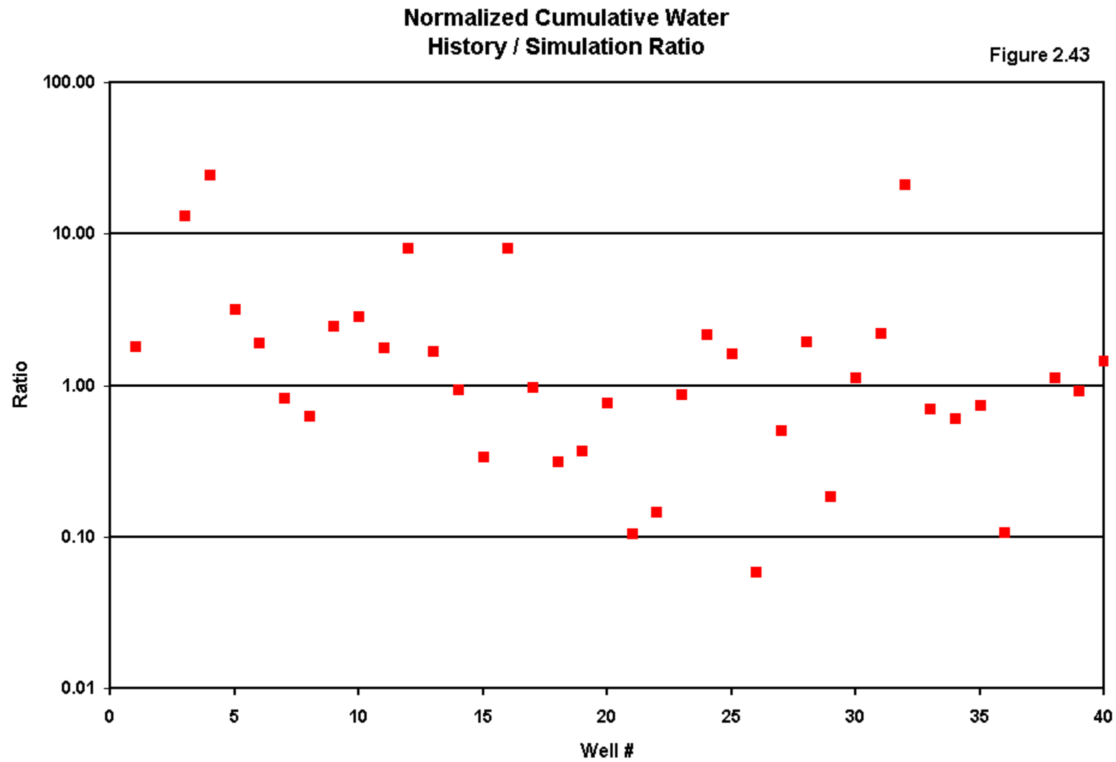
Normalized Cumulative Water
History / Simulation Ratio
Figure 2.43
100.00
10.00
1.00
0.10
0.01
Ratio
0
5
10
15
20
25
30
35
40
Well #

Figure 2.43

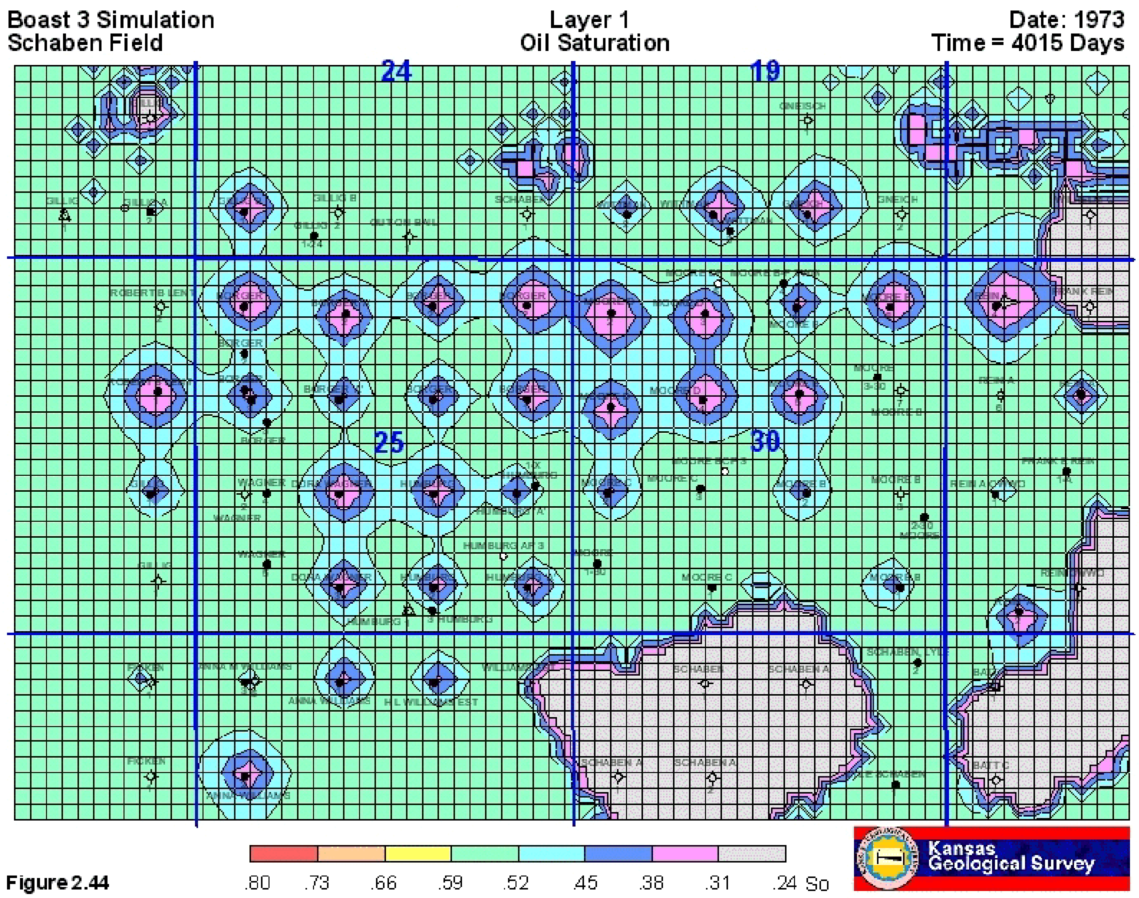
Boast 3 Simulation
Schaben Field
Layer 1
Oil Saturation
Date: 1973
Time = 4015 Days
24
19
25
30
.80
.73
.66
.59
.52
.45
.38
.31
.24
So
Kansas Geological Survey

Figure 2.44