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Producing Rich-Gas-Condensate Reservoirs--Case History and Comparison Between Compositional and Modified Black-Oil Approaches

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Abstract

This paper presents the results of a full field simulation study for a rich gas condensate reservoir with complex fluid behavior. Unique to this paper is a comparison between Modified Black-Oil (MBO) and compositional simulation in a full field model with water influx. Geological, petrophysical, fluid properties, rock-fluid properties, and well data were used to build two full field simulation models (14-component Equation-of-State, compositional model and 3-component MBO model). More than 14 months of daily gas, oil, and water production and tubing pressure data from 4 wells were matched using the MBO model. The model was then used to forecast production and identify new development locations. Comparison runs between the MBO and the fully compositional models were made. It was found that the two models agreed for the entire simulation above and below the dew point and with water influx from the aquifer. The MBO runs were at least 5 times faster than the most efficient compositional run.

The use of the MBO approach allowed a rapid history match of the field performance and a timely completion of the simulation study. Contrary to the common belief that a compositional simulation approach is needed for modeling near-critical reservoirs, this study shows that a MBO approach can be used instead of a fully compositional approach for modeling depletion and water influx processes in near-critical reservoirs. This approach may result in significant time saving in full field simulation.

Introduction

Reservoir simulation is often used to study a variety of problems. In this paper, we used reservoir simulation to study a rich gas condensate reservoir. After producing the field for approximately 400 days, it was decided to construct a full field simulation model and history match the field performance. The objectives of the study were to evaluate gas and condensate reserves, forecast field production, and optimize field development. The following discussion summarizes the results of the simulation study.

Field Background

The field is a moderate-size rich gas condensate reservoir with gas production rate of 55 MMscf/D from three wells, measured at the high-pressure separator (around 1,000 psia). The field produces from a high-temperature high-pressure offshore reservoir. Reservoir temperature is more than 310^{o}F and initial reservoir pressure is close to 14,230 psia (pressure gradient is approximately 0.9 psi/ft). Another well was added to boost the field production to 80 MMscf/D and the field is currently producing from four wells. Gas, condensate, and water are separated on the platform where they are metered and then mixed together and shipped through a pipeline to a gas plant. The fluids are separated once again at the gas plant and the gas is processed to strip out natural gas liquids.

Geological Model. Detailed log analysis on the four wells in addition to other dry holes in the area revealed that the main sand body in the reservoir is relatively clean with high porosity and low water saturation. The structure on top of the sand was mapped using 3D seismic data. Net sand map was drawn based on the log analysis with input from the geological model. An amplitude map derived from the 3D seismic data was used to guide the net sand map between the wells. The reservoir is highly faulted with a large-throw north-south fault that separates the reservoir into two completely isolated fault blocks. **Fig. 1** shows the structure map on top of the reservoir sand. The figure shows the two main fault blocks, several smaller blocks, and the location of the four producing wells.

Engineering Analyses. Production and flowing tubing pressure data for three wells were analyzed using advanced decline curve analysis techniques.[12] Decline curve analysis estimated reservoir permeability to be 20 to 100 md. A pressure buildup test was available on the discovery well (well #1). Permeability calculated from buildup analysis was approximately 30 md and the pressure data suggested a channel reservoir. This interpretation was consistent with the geological model for the subject sand.

Examining the production and surface flowing pressure for the three wells suggested that well #2 was isolated from the main reservoir. It was concluded that well #2 had been producing from a small fault block. Further investigation and PVT analysis confirmed this conclusion.

PVT Analysis. Surface fluid samples were originally collected from wells #1 and #2 before any significant production took place. The two samples underwent complete gas-condensate PVT analysis. The two samples indicated that the two fluids were different with well #2 fluid being near critical conditions. The important characteristics of the two fluids are shown in **Table 1**. According to McCain,[3] the fluid of well #2 is considered very near critical. This observation confirmed that the fault block of well #2 was isolated from the main reservoir.

Another fluid sample was taken from well #3 and showed the same fluid characteristics as well #1 sample.

Simulation Models

The structure and net sand maps were used to construct a 3D-grid model for the reservoir. Porosity estimates in the model were derived from log analysis performed on several wells. Initial permeability estimates were taken from the pressure buildup test and from decline curve analysis. We used industry correlations to calculate relative permeability and capillary pressure functions since special core analysis was not available for any of the wells. We also used Gray's correlation[4] to calculate vertical flow performance tables for each well. These tables are needed to relate bottom-hole flowing pressure and surface flowing pressure.

With these basic data, two simulation models were constructed: One model used a fully compositional approach and the other model used the Modified Black-Oil approach.[4]

Compositional Simulation Approach. Two equation-of-state, EOS, models for the two fluids were constructed using the Soave-Redlich-Kwong[6] (SRK) EOS with volume shifts as suggested by Peneloux *et al*.[7] Fluid viscosity was calculated using the Lohrenz-Bray-Clark[8] correlation. The procedure suggested by Coats and Smart[8] was used to match the laboratory measurements for the constant composition expansion (CCE) and constant volume depletion (CVD) experiments. We had to use 14-component fluid models to match the near-critical fluid behavior. **Fig. 2** shows the comparison between the observed liquid saturation in the CVD experiment and the calculated liquid saturation with the SRK EOS for well #2 fluid sample. The match is considered satisfactory given the high volatility of the fluid. **Fig. 3** shows better match for relative volume measured in the CCE experiment for the same near critical fluid.

MBO Simulation Approach. The MBO simulation considers three components (dry gas, oil, and water). The main difference between the conventional black-oil simulation and the MBO simulation (also called Extended Black-Oil) lies in the treatment of the liquid in the gas phase. The MBO approach assumes that stock-tank liquid component can exist in both liquid and gas phases under reservoir conditions. It also assumes that the liquid content of the gas phase can be defined as a sole function of pressure called vaporized oil-gas ratio, R_v (also referred to as r_s[10]). This function is similar to the solution gas-oil ratio, R_s, normally used to describe the amount of gas-in-solution in the liquid phase.

The two EOS models developed for the two fluids to calculate the PVT properties for the MBO simulation. PVT functions (oil formation volume factor), B_o, gas formation volume factor, B_g, solution gas-oil ratio, R_s, and vaporized oil-gas ratio, R_v) required for the MBO simulations were calculated using the procedure suggested by Whitson and Torp.[11] The PVT properties were calculated using the high pressure separator conditions since the available production data were measured at the high pressure separator.

History Match. The model constructed with the MBO approach was used to history-match the reservoir performance. Data available for history matching included daily measurements of three-phase production, measured at the high pressure separator, and surface tubing head pressure, THP, for the four producing wells. The main history matching parameters were the water-oil contact, WOC, for the main producing fault block and the permeability distribution in the reservoir. In the main fault block (where wells #1 and #3 are located), logs evaluation did not indicate a WOC.

All the runs necessary for history matching were made with the MBO model to save time. Gas production rate was specified in the simulation model (**Fig. 4**). The calculated condensate production rate, water production rate, and THP for all wells were compared with the actual values measured in the field. **Fig. 5** shows an excellent match of well #1 oil production rate while **Fig. 6** shows the match for water production rate from well #3.

Plan of Development Optimization. Several runs were made to optimize the field production. It was found that significant increase in recovery could be obtained by drilling one more well and sidetracking well #2 (poor producer) into the main fault block. The results also showed that using compression in all wells could increase the recovery factor by 8%.

Simulation Model Update. During the time of the original study, well #4 had tested gas condensate with similar fluid characteristics to well #1 but had not been completed. Two months after the completion of the initial reservoir study, daily production and surface pressure data became available for all four wells. The new data was used to update the history match and determine the volume of the poorly defined fault block.

The simulation model was validated once again after two more months with daily production and pressure data. The model predicted the actual performance accurately and neither the reservoir description nor the reservoir parameters had to be changed in the second update. This increased confidence in the accuracy of the simulation model. We are currently keeping the model up to date, so it can be used in managing the reservoir.

Comparison Between the Compositional and the MBO Approaches

After a satisfactory history match was obtained, the results of the MBO model were compared with the results of a 14-component compositional model. Both models were run in the forecast mode to compare their results. The agreement between the results of the two models was outstanding both above and below the dew point.

Figs. 7-10 show excellent agreement between the two models for gas production rate, oil production rate, water production rate, and field average pressure, respectively. The average reservoir pressure plot (Fig. 10) shows significant depletion below the dew point.

Comparisons between CPU times for different runs are given in **Table 2**. All runs were made on the same computer. CPU times were normalized with respect to the fastest run (fully implicit MBO run) to show the comparison in relative sense. The fastest compositional run (using the Adaptive-Implicit-Method, AIM[10]) was more than 5 times slower than the MBO run. Other methods were also tried for comparison.

The AIM[12] calculates pressure, saturation, and composition implicitly for a specified percentage of the total grid blocks. The grid blocks where wells are located usually experience high pressure and saturation changes during the run. Therefore, it is preferred to use implicit formulation for those grid blocks. We only specified 1% of the grid blocks to be solved implicitly using the AIM approach. This low level of implicitness was sufficient for this problem. By comparison, the equations in the IMPES (implicit pressure explicit saturation) approach are solved implicitly for the pressure and explicitly for both the saturation and composition. However, the equations in the IMPSAT approach are solved implicitly for the pressure and saturation and explicitly for the composition in all grid blocks.[13] This CPU time comparison shows that the AIM was the most efficient for modeling this reservoir using the compositional approach.

Discussion

It is generally believed that modeling the performance of gas condensate reservoirs below the dew point requires compositional formulation.[14] This study shows that the MBO approach can be adequately used for modeling gas condensate reservoirs above and below the dew point even for very rich (near critical) fluids. Although other authors[10,15] showed that this conclusion was true, their comparisons, however, were for single-well radial models and only under depletion process. Our results confirm the other authors' findings and extend them to include the cases with water influx. It seems, however, that the use of the MBO approach for below the dew point simulation is generally not acceptable among many of the practicing simulation engineers.

To the best of our knowledge, the comparison we present in this paper is probably the only one that uses a field-scale 3D model. It clearly shows the adequacy of the MBO approach to model gas condensate behavior above and below the dew point with also significant water influx from the aquifer.

Our results also suggest that the MBO approach can be used regardless of the complexity of the fluid. One of the fluids we had was very near critical, and yet the MBO approach proved to be adequate in modeling the performance above and below the dew point.

The use of the MBO model was crucial in our study. This approach allowed a rapid history match of the field performance and a timely completion of the simulation study.

Conclusions

In this paper we present the results of a simulation study for a gas condensate reservoir with complex fluid behavior. We also compare the MBO approach with the compositional simulation approach. Based on the results of the study, the following conclusions are drawn:

1. The MBO simulation model can adequately simulate the depletion and water influx processes for gas condensate reservoirs.
2. Contrary to the common belief, the MBO approach proves to be sufficient for modeling gas condensate behavior below the dew point.
3. Using the MBO approach, instead of a fully compositional approach, may result in significant time saving especially in full-field simulation studies.

Nomenclature

B_g = gas formation volume factor, resbbl/Mscf
B_o = oil formation volume factor, resbbl/STB
R_s = solution gas-oil ratio, Mscf/STB
R_v = vaporized oil-gas ratio, STB/Mscf

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TABLE 1 - CHARACTERISTICS OF FLUID SAMPLES

	Well #1	Well #2	Unit
Dewpoint pressure	5,480	5,225	psia
Condensate yield	177	363	bbl/MMscf
C_{7+} mole percent	6.48	12.69	%

TABLE 2 - NORMALIZED CPU TIME COMPARISON FOR DIFFERENT FORMULATIONS

Formulation	MBO	Compositional
IMPES	2.28	6.64
IMPSAT	-	15.56
AIM	-	5.24
Fully Implicit	1.00	100.42

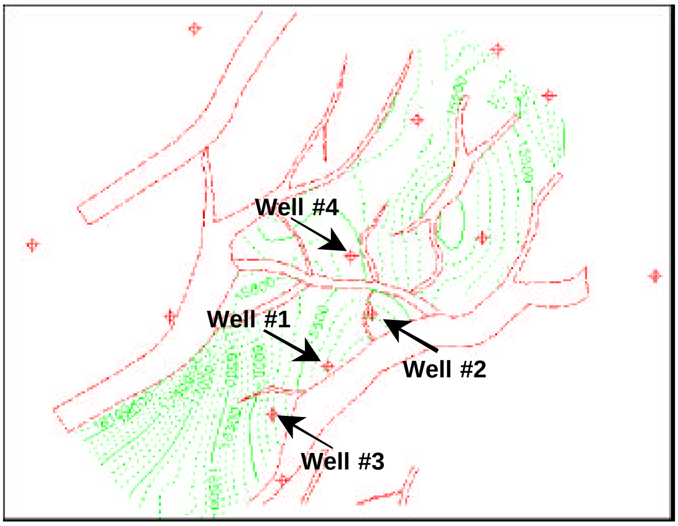

Fig. 1 - Structure map on top of sand.

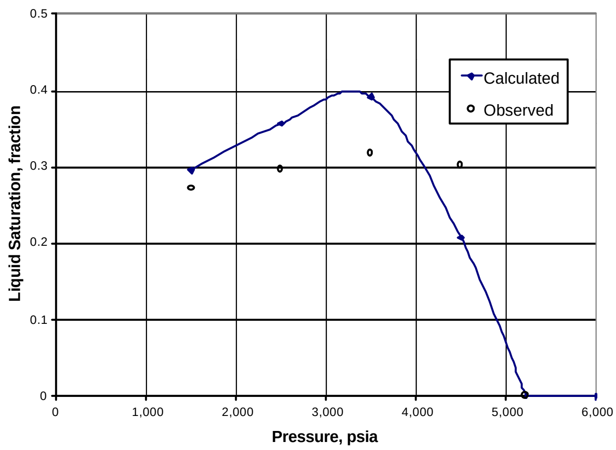

Fig. 2 - Match of liquid saturation of the CVD experiment for the near-critical fluid sample.

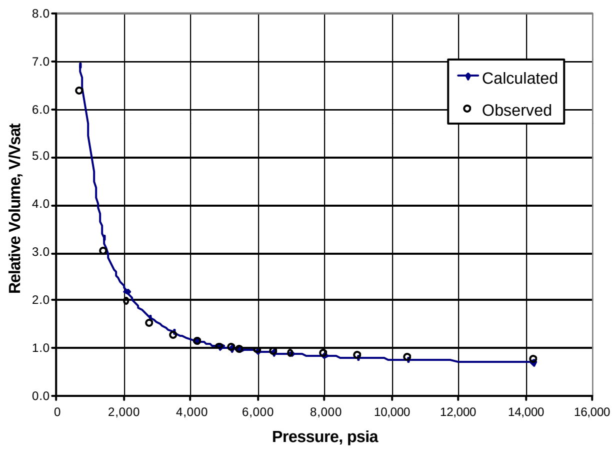

Fig. 3 - Match of relative volume of the CCE experiment for the near-critical fluid sample.

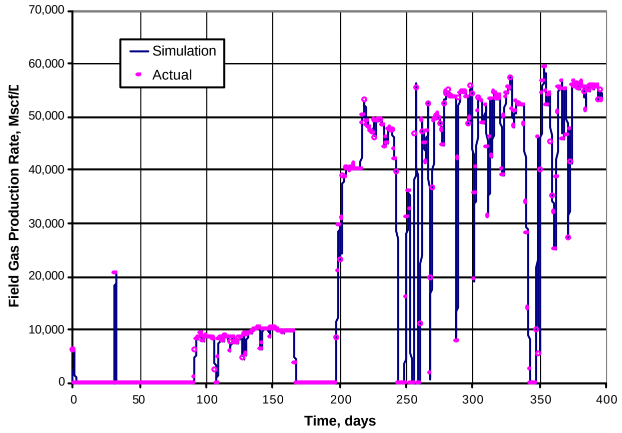

Fig. 4 - Field gas production rate.

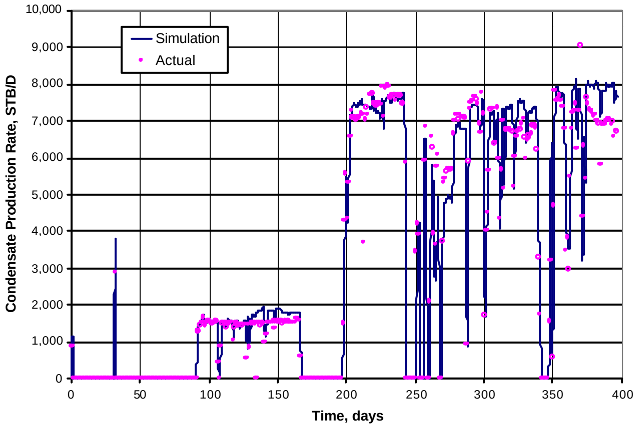

Fig. 5 - History match of condensate production rate for Well #1.

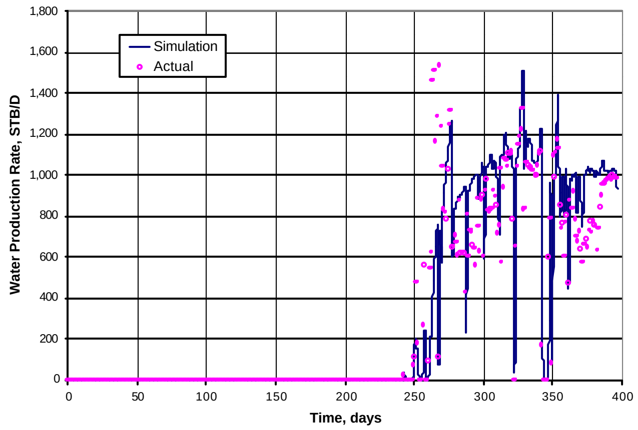

Fig. 6 - History match of water production rate for Well #3.

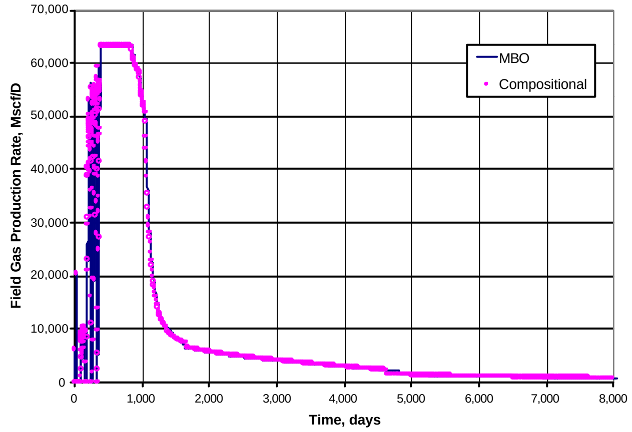

Fig. 7 - Comparison between MBO and compositional simulation (field gas production rate).

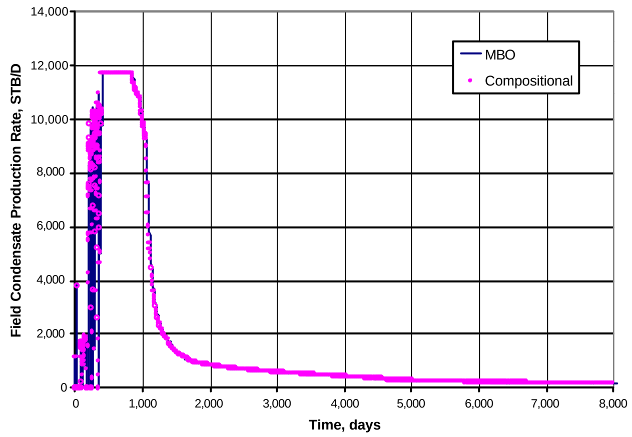

Fig. 8 - Comparison between MBO and compositional simulation (field oil production rate).

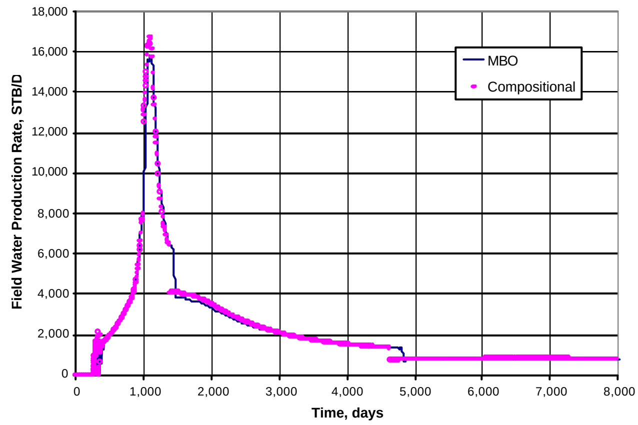

Fig. 9 - Comparison between MBO and compositional simulation (field water production rate).

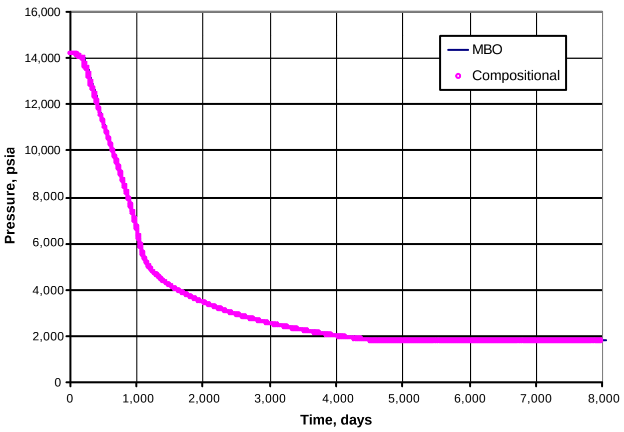

Fig. 10 - Comparison between MBO and compositional simulation (field average pressure).