Cross-Discipline Integration in Reservoir Modeling

A new technique has been developed to model 3D permeability distribution. The technique integrates all available data into a fluid-flow simulation model. The integrated-modeling process honors the essential aspects of established reservoir descriptions as well as the geological-facies model and engineering data. Data integration of the fluid-flow simulation improved the accuracy of the resulting well-performance predictions and decreased the time required for reservoir model history matching.

Introduction

There is an increasing demand for detailed geological numerical models that incorporate all available data into reservoir-characterization studies for the purpose of fluid-flow simulation. Conventional modeling techniques, which lack the ability to quantitatively integrate data, tend to produce homogenous results of reservoir properties in the interwell regions. When these models are fed into reservoir simulations for performance predictions, the results may be biased and unreliable. Therefore, a method is required that integrates all available data, despite differences in scale, to improve the predictive power of the models and enable quicker production history matching from the reservoir simulation.

Data integration is a primary reason to use geostatistics in the reservoir modeling process. It allows the incorporation of diverse data of varying scales, including very descriptive data (such as conceptual geologic interpretations) or measurements (such as 3D seismic time traces, their derivatives, and the resulting interpretations). Geostatistical tools can use information such as 3D seismic data to contribute directly or indirectly to the modeling of the interwell regions. This method may provide significant risk reduction in reservoir development and management.

The full-length paper details a geostatistical method that integrates geophysical, geological, and engineering data in reservoir modeling. The Hawtah field in central Saudi Arabia was used to demonstrate the approach.

This article is a synopsis of paper SPE 62902, "Cross-Discipline Integration in Reservoir Modeling: The Impact on Fluid-Flow Simulation and Reservoir Management," by ***Hisham M. Al Qassab,*** *SPE,* ***John Fitzmaurice, Zaki A. Al-Ali,*** *SPE,* ***Mohammed A. Al-Khalifa,*** *and* ***G. A. Aktas,*** *Saudi Aramco, and* ***Paul W. Glover,*** *U. of Aberdeen, originally presented at the 2000 SPE Annual Technical Conference and Exhibition, Dallas, 1–4 October.*

Stratigraphic and Reservoir Architecture

The Unayzah reservoirs in the Hawtah field comprise rocks of continental origin, organized in a highly complex fashion. Untangling the complex facies architecture of these reservoirs required several evolutionary stages. Earlier ideas advocated a complex picture with a relatively random distribution of reservoir and nonreservoir facies. However, more recent detailed stratigraphic and sedimentological studies suggest that the rock architecture is much better organized than originally believed. A sequence-stratigraphic scheme with 15 zones was applied to enable a better understanding of reservoir prediction and connectivity for most of the reservoirs.

Depositional-Facies Maps and Model

A facies model identifies the spatial distribution of rock types that control fluid-flow behavior. One difficulty is the availability and quality of core data that define rock or facies types. Therefore, a two-fold method was used. First, the facies types and associations are identified in terms of depositional environment from cored wells to explain geological characteristics in details that are geologically sound. Once the facies are identified at cored wells, they are extended to noncored wells that have well logs available. The output from this method is a foot-by-foot determination of depositional-environment-facies types in each well in the field.

Petrophysical Rock Model

Examination of reservoir properties for the different depositional-environment facies, such as porosity and permeability, indicated substantial overlap. Therefore, it was concluded that depositional-environment facies could not be used alone to determine reservoir flow units. A cluster analysis was used to establish petrophysical rock types for all wells on the basis of eight electric-log curves. These petrophysical rock types then were cross-referenced with core data. The result showed three main petrophysical rock types, each with a distinct reservoir quality.

An attempt was made to build a 3D petrophysical rock model defined at the wells, but the resulting model had no geological character or meaning. Therefore, it was decided to combine the environment with the depositional-facies model built earlier, which is fully supported by the geologist, with the petrophysical-rock-type model, supported by the reservoir engineer, into a single integrated facies model. Combining the models was accomplished by distributing the petrophysical rock types defined at the wells within each environment of depositional facies separately.

Stochastic Seismic Inversion

A poststack amplitude inversion was performed to incorporate seismic impedance data into the model. The available seismic data was transformed from wiggle-trace information to acoustic impedance (AI) to be useful for influencing 3D reservoir descriptions. This transformation and integration explicitly considered that the seismic-based information is an imperfect predictor of well impedance logs, and subsequently, an even less perfect predictor of facies.

Stochastic inversion was used in place of the conventional deterministic approach, which gives absolute impedance results with resolution

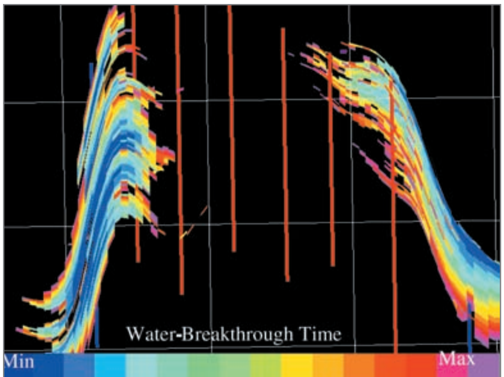

Fig. 1—Cross-section of an integrated model showing water-breakthrough time. Note the stratification (right side) of the reservoir.

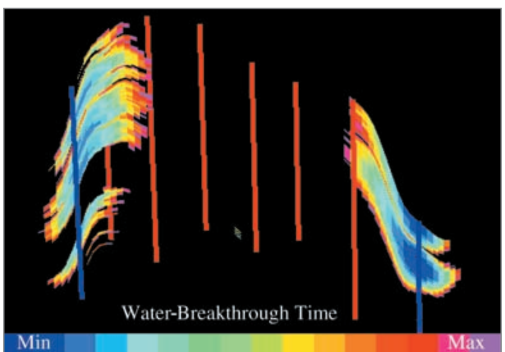

Fig. 2—Cross–section of a conventional model showing water-breakthrough time. Note the uniform fluid front (right side) of the reservoir.

dependent on the inherent seismic bandwidth. The stochastic inversion approach capitalizes on stochastic simulations. The stochastic inversion approach honors the constraining-well impedance logs along with their vertical resolution as well as the specified univariate and bivariate statistics of impedance by area or zone.

Time to Depth Conversion of AI

Reservoir modeling is carried out in the depth domain, which requires the conversion of seismic AI from the time to the depth domain. The conversion can be done simply by snapping the impedance values between two markers, which are equivalent to the same depth markers, into a predefined 3D grid. AI data between each of the 15 zones (available in time domain) were snapped to the corresponding 15 zones in depth. This conversion from one domain to another is considered an implicit conversion.

AI Porosity Relationship

Well data were thoroughly examined by means of univariate and bivariate analysis such as histograms and scattergrams respectively, to look for a systematic relationship between well AI and porosity. A strong AI/porosity relationship was found after the data were segregated by petrophysical rock type. The better the reservoir quality of the rock, the higher the correlation coefficient between porosity and AI. However, in the nonreservoir rock, the relationship between the two variables is lost. As a result, facies modeling plays a major role in determining how much weight the seismic data should have to influence the estimation of porosity in the interwell regions.

Porosity and Permeability

A 3D porosity model was built by use of the high-resolution impedance model and the proper correlation coefficient for each rock type as defined in the 3D petrophysical rock model built earlier. The sequential Gaussian simulation was used because of its ability to generate models of porosity that capture the heterogeneity of the reservoir as well as its power to generate multiple realizations that can be ranked for use with fluid-flow simulation tools. In this case, only one realization of porosity was selected for fluid-flow simulation.

Permeability curves were constructed for each well in the field by honoring the permeability-thickness from pressure buildups, flowmeter profiles, and core-permeability data. The flow profile is used to allocate the total or gross measurement of pressure buildup to a higher-resolution permeability log.

Fluid-Flow Performance

To determine the level of accuracy of the two approaches and the advantage of data integration, fluid-flow simulations were run. Several criteria were set to determine the level of accuracy, which included water-breakthrough time, CPU time required to history match, and fluid-flow movement pattern.

The simulation model was constructed with permeability, porosity, depth, cell thickness, and petrophysical rock types in the case of the integrated model. To eliminate inherent errors associated with upscaling, no upscaling was performed on either set of models.

Waterfloods were modeled with a streamline simulator, and the porosity and permeability distributions were obtained from both the conventional and integrated approaches. Quick-look waterflood simulations provided water-breakthrough times, fluid-front behavior, and water-cut comparisons. A detailed fluid-flow simulation used a finite-difference simulation technique for both approaches to assess the required CPU time for history matching, and the pressure and error analysis comparisons.

Results

Each set of models, when fed into fluid-flow simulation, produced very different flow results in terms of breakthrough times and fluid movement patterns. **Fig. 1** shows that in the integrated models, water had a preferred direction through thin zones of high permeability as captured by the stratification of the reservoir model that mimics the field data. By contrast, **Fig. 2** shows that for the conventional approach the fluid-front movement has no preferred direction throughout the model because the conventional reservoir model is more homogenous compared with the integrated model. The water-arrival time computed with the integrated model is a much closer match to the field data than that of the conventional model.

The fluid-flow simulation results indicate a significant effect on accuracy in both history-matching time and well performance. The error at each time step for the integrated models is smaller and more stable than the errors from the conventional nonintegrated model. The calculated pressures from the integrated model simulation match the observed pressure data well. The calculated pressures from the conventional model simulation overestimates the observed pressures by up to 25%. **JPT**

Please read the full-length paper for additional detail, illustrations, and references. The paper from which the synopsis has been taken has not been peer reviewed.