

Z-99 Production assessment of reservoir models constructed with the use of 3D seismic data

GAMBUS, M. AND TORRE S-VERDÍN, C.

Department of Petroleum and Geosystems Engineering, The University of Texas at Austin

Abstract

This paper describes a study undertaken to appraise spatially complex hydrocarbon reservoir models constructed with the use of 3D post-stack seismic data and well logs. Developments are centered about the interpretation of data acquired in an active gas field in the deepwater Gulf of Mexico. The availability of time records of fluid production provides an independent way to quantify the accuracy and reliability of several methods commonly employed to construct reservoir models. We make use of geostatistical inversion to construct spatial distributions of porosity and permeability that honor well logs and 3D post-stack seismic data in the inter-well region. The constructed reservoir models are compared against models constructed with standard geostatistical procedures that do not make use of seismic data. Multi-phase fluid-flow simulation is performed to assess the consistency of the constructed reservoir models against the existing time record of flow rates of gas/water and shut-in well pressures. For the field study under consideration, it is found that geostatistical inversion consistently yields the closest match to dynamic measurements of reservoir pressure and fluid production.

Introduction

The objective of this paper is to integrate 3D seismic data, well logs, rock core measurements, and time records of fluid production in the construction of hydrocarbon reservoir models. Well logs and core plugs are often the only source of information used to construct reservoir models amenable to simulation of production behavior. Amplitude variations of 3D seismic data are difficult to integrate into the process of reservoir construction because of their relatively low spatial resolution and because they are seldom sensitive to rock fluid properties such as permeability, relative permeability, and capillary pressure. Practical methods used to construct reservoir models require a rapid assessment of the relative importance of spatial detail in the distribution of petrophysical properties (e.g. porosity, and permeability), versus knowledge of fluid and rock fluid properties. We address some of these technical issues using as example a field data set acquired in the deepwater Gulf of Mexico.

Methodology

Reservoir Description. The reservoir under consideration is an active gas field located in the deepwater Gulf of Mexico, between 8,500 and 10,500 feet below the sea level. Reservoir units are Lower Pliocene sands interpreted as amalgamated channel sands flanking a salt structure. Two exploratory wells and sixteen development wells were drilled after the initial discovery. However, only two of these wells, A9ST and A8, were completed in the reservoir unit considered in this paper. Figure 1 shows the well trajectories overlain on a plan view of P-wave acoustic impedance (AI) within the hydrocarbon zone. The dimensions of the reservoir unit are approximately 1.5 km x 1.5 km horizontally, and 145 m in the vertical direction. Due to the proximity of the salt dome, reservoir sands exhibit dip angles of up to

27°. To date, the two wells have produced in excess of 19.9 BCF of gas and 1,000,000 bbls of oil. The 3D post-stack seismic data acquired in the area of study consist of traces sampled at 4 ms in the frequency band between 10 and 70 Hz, and with a central frequency of 25 Hz.

Rock Physics Model. We made use of Simandoux and Coates-Dumanoir models to generate permeability logs (Balan et al., 1995). Porosity logs were corrected for shale and hydrocarbon presence and successfully compared against core data. A good correlation was observed between AI, porosity, and logarithmic permeability. Good quality sands exhibit low values of AI while poor quality sands and shales exhibit high values of AI. The high correlation between AI, porosity, and logarithmic permeability allows the quantitative use of seismic amplitude variations to interpolate petrophysical properties in the inter-well region. Reservoir models were constructed using (a) conventional geostatistical interpolation of well logs and core data via sequential Gaussian simulation (SGS), and (b) geostatistical inversion of well logs and 3D post-stack seismic data (Grijalba-Cuenca et al., 2000).

Fluid Flow Model. A structured corner point fluid-flow grid was constructed with cell dimensions equal to 81 ft x 41 ft x 34 ft to model a closed reservoir with an active aquifer and two producing wells. Reservoir cells were assigned petrophysical properties (porosity and permeability) using either SGS or geostatistical inversion. The cellular reservoir model was transformed from seismic time to depth and input to a commercial fluid-flow simulator. Corey-type relative permeability and capillary pressure curves were used for the simulations of dynamic reservoir behavior after the onset of production.

Results and Discussion

Figure 2 shows plan views of porosity models constructed with sequential Gaussian simulation. The various independent realizations described in this figure are substantially biased by existing well locations. Figure 3, on the other hand, describes independent realizations of porosity models constructed with geostatistical inversion. The latter models reveal significantly more spatial detail in the distribution of porosity than those obtained with SGS.

Multi-phase fluid flow simulation and history match provide an independent quantitative method to appraise the consistency and reliability of the constructed spatial distribution of reservoir properties (Mattax and Dalton, 1990). In the field study considered in this paper, three years of production were available to history match the simulated production. Oil flow rates in each well were specified in the simulator with water/gas production rates and pressure used as the matching output. Figure 4 shows the time record of static reservoir pressure after the onset of production. This figure indicates that reservoir models constructed with SGS do not match the measured static pressures, whereas reservoir models constructed with geostatistical inversion yield unbiased and accurate time records of pressure. Another example is described in Figure 5, where the cumulative water production in well A9ST favorably matches the production measurements simulated from reservoir models constructed with geostatistical inversion.

Conclusions

The use of seismic amplitude data in the construction of reservoir models introduces a degree of spatial variability not captured by standard geostatistical methods that rely exclusively on well logs. For the field study considered in this paper, we have shown that uncertainty in the dynamic behavior of reservoir models is significantly reduced when static reservoir models

are constructed with the use of 3D seismic amplitude data. Comparison of the measured and simulated time records of fluid production provides an unparalleled, independent method to weigh the relative importance of spatial detail in reservoir parameters against knowledge of fluid properties not accessible through seismic data.

Acknowledgements

The authors thank UNOCAL Corporation for the release of the data set reported in this paper. Our gratitude goes to Jason Geosystems and Schlumberger for their generous donation of software. Partial funding of this work was provided by the U.S. Department of Energy under contract No. DE-FC26-00BC15305.

References

Balan, B., Mohaghegh, S., and Ameri, S., 1995, State-Of-The-Art in Permeability Determination From Well Log Data: Part 1- A comparative study, model development: SPE Eastern Regional Conference and Exhibition, Morgantown, West Virginia, September 17-21, contribution no. SPE 30978.

Grijalba-Cuenca, A., Torres-Verdín, C., and Debeye, H.W., 2000, Geostatistical inversion of 3D seismic data to extrapolate wireline petrophysical variables laterally away from the well: SPE 63283 presented at the Annual Technical Conference and Exhibition, Dallas, TX.

Mattax C., and Dalton R., 1990, *Reservoir Simulation*, SPE Monograph Volume 13, Richardson, Texas.

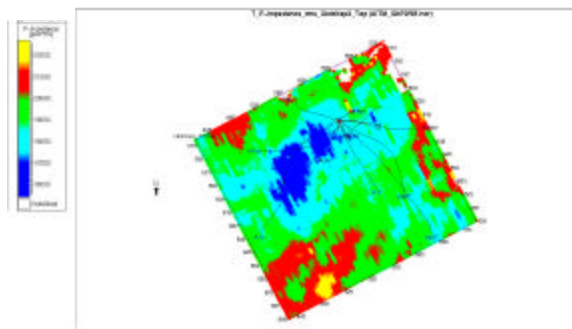


Fig. 1. Plan view of the well trajectories overlain on a map of P-wave acoustic impedance.

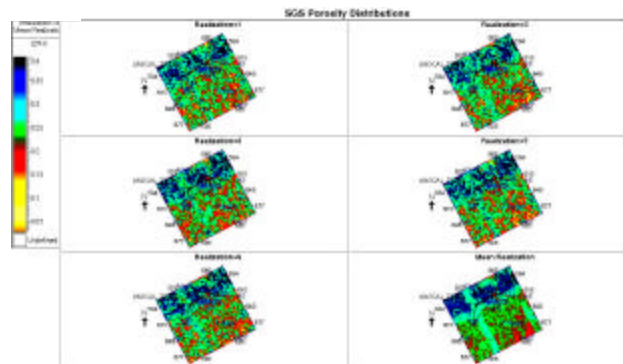


Fig. 2. Plan view of the spatial distribution of porosity obtained with sequential Gaussian simulation (SGS) based on well logs only. From left to right, and from top to bottom, realization no. 1, 3, 5, 7, 9 and the mean of 10 realizations.

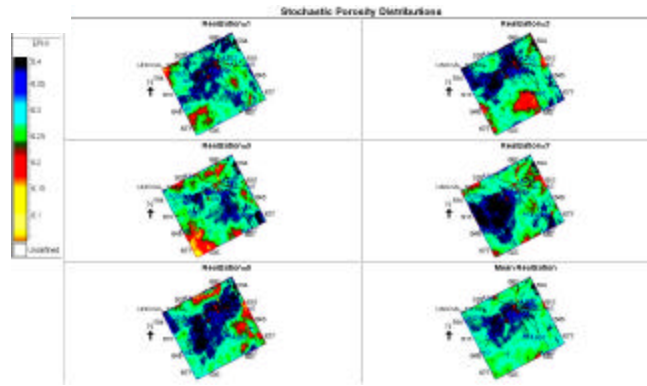


Fig. 3. Plan view of the spatial distribution of porosity obtained with geostatistical inversion of well logs and 3D post-stack seismic data. From left to right, and from top to bottom, realizations no. 1, 3, 5, 7, 9 and the mean of 10 realizations.

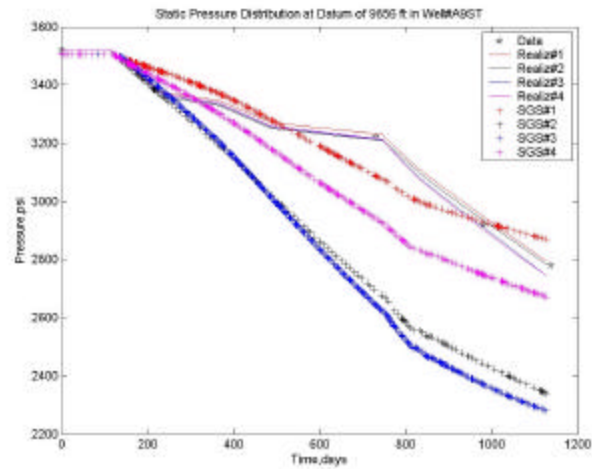


Fig. 4. Time evolution of static pressure in well A9ST after the onset of production. Solid lines describe pressures simulated from reservoir models constructed with geostatistical inversion. Dashed lines describe pressures simulated from reservoir models constructed with SGS.

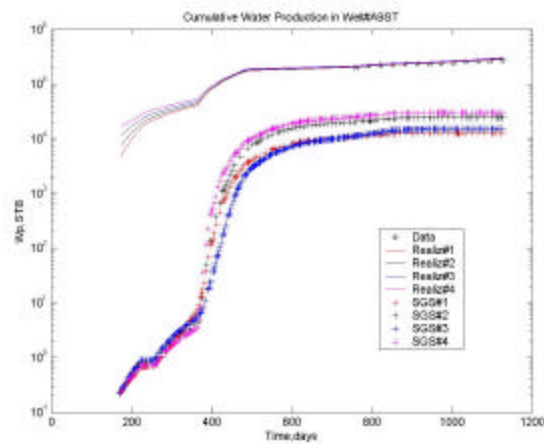


Fig. 5. Cumulative water production in well A9ST. Solid lines describe pressures simulated from reservoir models constructed with geostatistical inversion. Dashed lines describe pressures simulated from reservoir models constructed with SGS.