AAPG Annual Meeting
March 10-13, 2002
Houston, Texas

Maximizing field recovery through improved reservoir characterization and simulation: The L-P Sands of Dacion Field, Eastern Venezuela Basin.

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Introduction

The Dacion Field is located in the Oficina Basin of Eastern Venezuela and produces from Miocene deltaic and marginal marine reservoirs (Figure 1). The field was discovered in 1949 and originally contained about 1,700 MMBO. By early 1998, the field had produced 260 MMBO under natural waterdrive and oil rates had fallen to less than 8,000 BOPD. To increase these rates and maximize recoveries, a redevelopment plan of infill drilling and workovers was initiated along with the installation of new facilities capable of handling oil rates of 70,000 BOPD.

The drilling program was driven by the interpretation of newly-acquired 3D seismic data, a fieldwide remapping exercise, and the generation of dynamic models for key reservoir intervals. One of these intervals is the Dacion L-P Sands (or informally 'Mid Sands'), which consists of thinly-bedded (2-5 meters) lower delta plain/marginal marine sands, shales and coals in the Oficina Formation (Figure 2). Several reservoir models were constructed for this interval to understand reservoir performance and optimize development.

A geostatistical approach was chosen for the geologic modelling work because of the difficulty in correlating sandstone bodies between wells, and in predicting sandbody distribution and connectivity away from the wells and into the aquifer. Geostatistical modelling was also chosen because of its ability to capture fine-scale vertical and lateral permeability variations. This is critical in Dacion because the oil is heavy, leading to viscous fingering of the water through higher permeability streaks and causing early water breakthrough in producers.

Reservoir Characaterization and Modelling

The modelling process began by tying interpreted 3D seismic surfaces to the interval of interest as defined in the wells. The seismic surfaces were also checked against a well log zonation created by correlating thin, laterally-continuous coal horizons. The resulting stratigraphic framework provided a well-constrained volume into which facies bodies could be distributed. Facies types were identified using core and log data, and facies bodies were distributed using object modeling techniques. The location, abundance, geometries, and orientations of these bodies were derived from a combination of log, seismic, and analogue data. The bodies were distributed as objects using a simulated annealing process.

Log data from over 200 wells were used to condition the distribution of these bodies. In order to capture the complexity of the system while honoring genetic relationships and erosional hierarchies, successive realizations and merges were carried out. This ensured, for example, that distributary channels were appropriately positioned relative to their associated mouth bars and crevasse splay deposits.
After completing each facies realization, porosity values calculated from well logs were distributed by facies type using Sequential Gaussian Simulation. Permeabilities were distributed using transforms based on the relationship between core porosity and core permeability. These permeabilities were checked against well test permeabilities to ensure their reasonableness. Recent air-brine capillary pressure data were normalized with a J-function and used to build a series of height vs saturation curves. Saturation values were then assigned to each cell in the model by relating the values of porosity and permeability in each cell to the appropriate height vs. saturation curve.

For each geologic model, multiple realizations were generated to characterize the range of uncertainty for various parameters. For the Dacion L-P Sands, the key parameter tested was the interconnectedness of facies bodies. Variations in sand-body connectivity will determine whether paths exist for water to move updip from the aquifer to support producers, whether areal and vertical sweep will be efficient, and whether interwell locations are likely to contain unswept sands. Testing this parameter is especially important in moderate net-to-gross ratio reservoirs like Dacion, where the degree of interconnectedness can range from 30 to 90 percent.

The modelling workflow is summarized in Figure 3.

Streamline and Reservoir Simulation

After generating multiple realizations of each geological model, these realizations were up-scaled and subjected to streamline simulation. In this model, streamlines simulate the movement of water from the aquifer to updip producers as a function of the pressure difference between the two areas, and the relative ease of fluid flow through the cells separating them (permeability). Prior to running the model, average well rates were entered for all L-P Sands producers and a row of injectors (pseudowells) was added to mimic aquifer influx. When the model is run, streamlines are generated between the aquifer and updip producers, with the density of the streamlines being related to the degree of sweep.

To quantify the streamline results and compare sucessive realizations, a parameter to evaluate connectivity and heterogeneity of successive realizations, was genereated. This combined permeability, saturation and a ‘time-to-producer’ value. (Time-to-producer values are a measure of how long it takes for fluid to move from a cell to a producer, with cells that take the longest time being the most poorly-swept). Each realization was filtered to include only “unswept” oil-bearing cells. These are cells with permeabilities greater than 100 millidarcies, water saturations of less than 60 percent, and time-to-producer values of greater than 10,000 days. Realizations with the most unswept cells were considered to be the most heterogeneous realizations, and those with the fewest unswept cells were considered to be the least heterogeneous. For each model, these two realizations, plus a third realization representing a mid-range heterogeneity, were selected for reservoir screening simulation.

The three screening simulation models were initialized, run, and compared to the overall reservoir production history. The realization that most closely matched this history was selected for detailed history matching and forecasting in a reservoir simulator. During the history match process, the chosen model was adjusted to more closely match production and pressure data.

Results and Lessons Learned

Base case forecasts were generated to provide an estimate of the expected production without additional development. The results of these forecasts were analyzed and alternate development plans were created. The resulting work showed that additional development, including infill drilling and water injection, can result in incremental recoveries of 6 to 18 percent of OOIP, depending upon the area of the field and the development plan.

These findings demonstrate the value of detailed reservoir description and simulation work in optimising development plans. In addition, the work provided numerous insights into the modelling process. One key observation was that despite all of the geologic and streamline modelling work that was conducted, the quality of the detailed well history match during reservoir simulation was quite variable. Part of this was due to the quality of production and pressure data available for history matching. But part of this was also due to the way in which the geologic and streamline modelling work was conducted.

In the geological model, more work is needed to define the location and lateral extent of coal seams. Most were treated stochastically, by inserting them into individual wells. In reality, a number of these seams may be continuous between wells, and should be deterministically placed in the model. Although this is a difficult and time-consuming process (with many old wells having logs of variable quality, and no density logs), it would create lower values of vertical permeability, leading to a better history match. Also, the seismic was not used to help distribute the reservoir bodies. Current work is focused on using elastic properties to differentiate between sands and shales, and on the potential of full elastic inversion to help guide the distribution of facies bodies.

With respect to the streamline modelling, this work may be more valuable if conducted on geologic models prior to upscaling. The upscaling process may result in unrepresentative results when dealing with thinly-bedded reservoirs.

Where upscaling is unavoidable, an assessment of how closely the geologic architecture is captured in the upscaled model, could be made by comparing the connected body volume size distribution between the upscaled and non-upscaled models. Those upscaled models which have similar body size distribution to the geologic model could be selected for detailed history matching. Figure 4 suggests that the upscaled model plotted on the right–hand side, has better captured the body connectivity of the geologic model, than the one on the left. There may also be value in extracting and modelling the key connected body volumes themselves, which may enable upscaling to be avoided by requiring less computing power.

Using 2-phase streamline routines, with which it is possible to produce production forecasts, geological-scale realizations could be used to examine the uncertainty in predicted production profiles. This may also help in selecting which geological realizations should be concentrated on, for more detailed simulation modelling and forecasting.

Figure 1: Location Map – Dacion Field, Oficina Basin Venezuela

Schematic illustration of the Oficina Formation depositional setting (not to scale).

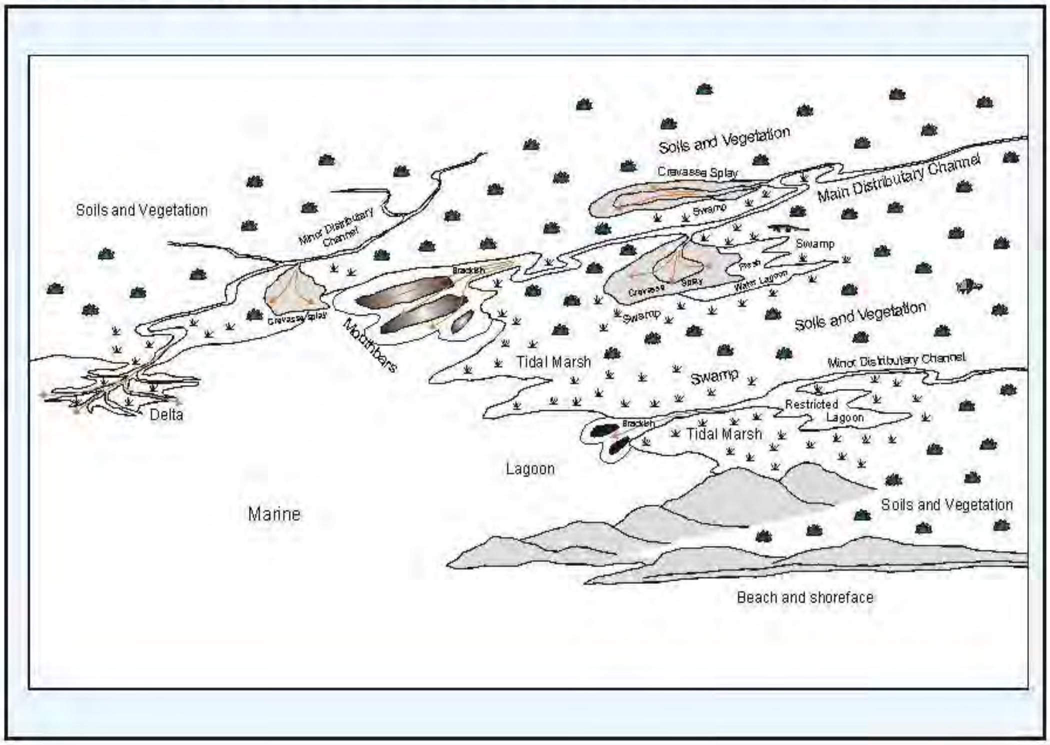

Figure 2: Oficina Formation Depositional Model

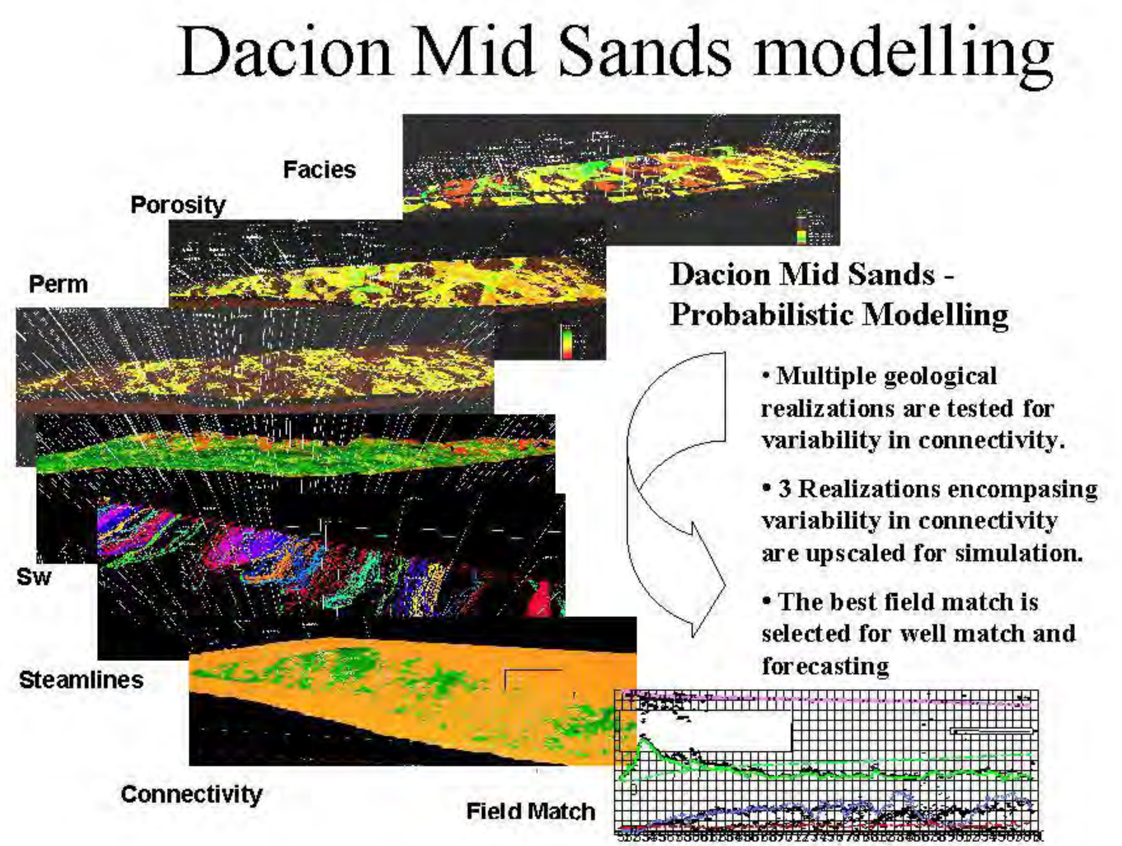

Figure 3: Stochastic Modelling Process

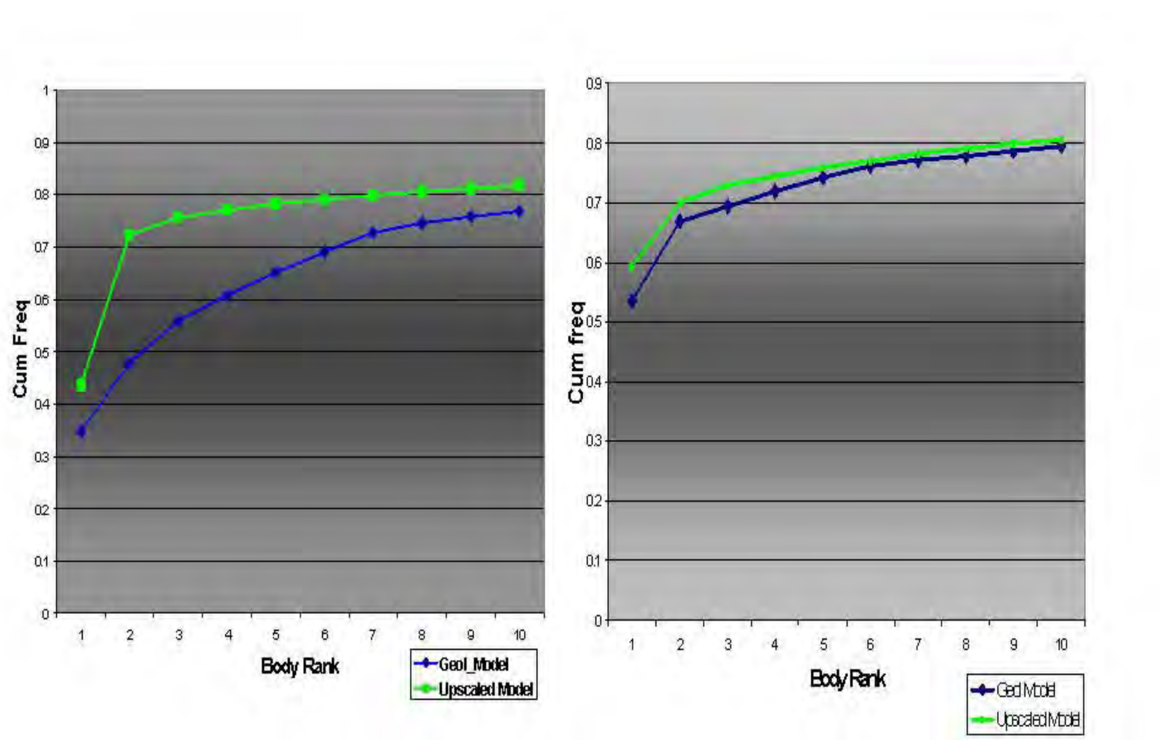

Figure 4: 2 Realizations of Geologic v Upscaled Model Connected Body Distributions