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by **David Grimes** (speaker),
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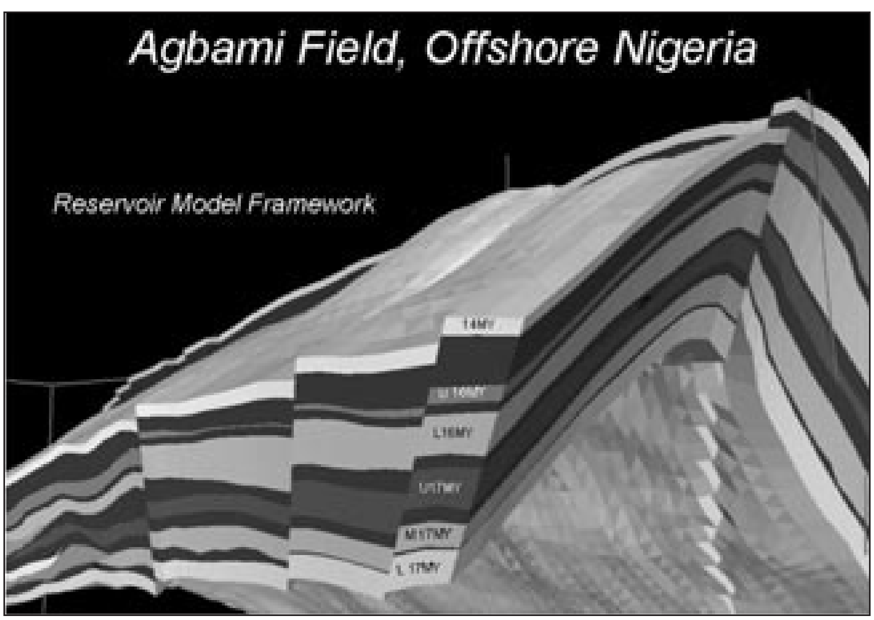
ChevronTexaco Overseas Petroleum

Agbami Field, Nigeria—Addressing Challenges and Uncertainty

Agbami Field was discovered in late 1998, approximately 105 km offshore Nigeria in the Gulf of Guinea. The field is located in Blocks OPL216 and 217 in approximately 1500 meters of water. The structure is a northwest to southeast trending detachment fold anticline covering an area of 180 km2 at spill point. The discovery well, the Agbami No. 1, was drilled by Star Deep, a wholly owned subsidiary of Texaco, Inc. acting as technical advisor to FAMFA, an indigenous Nigerian oil company. Star Deep brought Petrobras in as a partner and followed the discovery with three appraisal wells and one sidetrack in Block OPL216, plus Statoil drilled the Ekoli 1 well into the same structure in adjacent Block OPL217. In late 2003 and early 2004, drilling resumed with ChevronTexaco, also through Star Deep, adding the first 2 wells from the development plan. After a short drilling pause to acquire seismic data, these wells will be followed by further development drilling later in 2004. All wells to date have penetrated oil bearing sands. The field is a world class development opportunity with significant resources.



The pay intervals at Agbami field consist of two principal zones. The primary reservoirs are in the 17 million year old (MY) sands and contain about 80% of the reserves. These objectives include slope channel, slope fan, and basin floor fan facies that offer both stacked and isolated reservoir objectives. Secondary reservoirs are present in the 13MY/14MY/16MY sands. These shallower productive zones are comprised of channel and levee-overbank facies.

Seismic Data Issues

The seismic reflections from the shallower, secondary reservoirs occur above the water bottom multiple and are of relatively good quality. Amplitude extractions of both near and far angle data match predicted AVA models. We can interpret stratigraphic and fluid changes from the seismic data at this level.

However, the seismic data from the deeper, main pay intervals in the 17MY interval suffer from several data limitations. Principal among these is significant multiple energy contamination. Multiple generating surfaces exist not only at the water bottom, but also at other shallow horizons below mudline. The energy from these multiples occurs at the same time as the main pay interval primary reflections over much of the field, seriously degrading the data, especially in the pre-stack domain. Earlier processing of the data during the exploration and appraisal phases of the field, while attenuating the multiples, did not adequately resolve the problem. Consequently, extracted amplitudes from the 3D seismic data did not follow expected Class II AVA behavior. Recent reprocessing efforts by ChevronTexaco using a Gaussian beam

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method for attenuation of the multiples have given encouraging results that should allow better characterization of the reservoirs from seismic in future reservoir models.

Additionally, wavelet estimations from the seismic data indicate that the frequency content is relatively low, limiting the ability of the seismic to resolve pay sands. Multi-sand intervals tend to image as low frequency, high amplitude far-angle reflectors with typically two or three sands imaged by one peak-trough-peak seismic event.The minimum sand thickness detectable at the main pay intervals in these data is about 30 meters.

Also, reflectors from the inboard limb of the fold at the north-west end of the structure have diminished stacked amplitude responses and in general, the inboard limb is less well imaged than the outboard limb. Shallow toe thrusts north of the field appear to be masking far offset traces that would normally contribute to the expected high amplitude far angle reflections of oil-bearing sands. To record higher angle traces in this area, and hence better map the sand distribution, we are proposing to re-acquire data parallel to this thrust front.

Reservoir Modeling

With the limited frequency content of the seismic data, stratigraphic information from seismic was restricted to the identification of thick, sandstone-prone fairways that were mapped throughout the field area as architectural elements in the reservoir model. Tying to the low frequency inversion data placed the seismic tops and bases of these architectural elements in the shales above and below the corresponding sandstone unit in the well logs. This architectural element interpretation forms the basis for well-to-well correlation, field volumetrics and reservoir modeling.

A *channelized sheet* system was selected as the most likely depositional model for the 17MY reservoir based on the available seismic and well data. To fully capture the potential range of depositional systems and associated in-place volumes and connectivities caused by variable net-to-gross and reservoir architecture, four end-member models were also created: *isolated channel, isolated sheet, amalgamated channel* and *amalgamated sheet*.

The resulting earth models (three hundred in all) were statically and dynamically ranked using streamline flow simulation to select low-, mid-, and high-case earth models for use within Experimental Design (ED) to supply probabilistic production forecasts. In addition to a range of earth models, a range of other geologic and petrophysical parameters were supplied for use in ED, including permeability, permeability contrast, number of faults and fault seal/transmissibility.

The limited number of wells and low resolution seismic data result in considerable uncertainty with respect to many elements of the geological model. To fully understand the range and impact of these uncertainties, probabilistic volumetric analyses were completed using Crystal Ball. The P_5-P_{50}-P_{95} in-place probabilistic volumes were used as a benchmark to verify that the range of in-place hydrocarbons in the earth models was reasonable.

This workflow provided a methodology for testing the Agbami field development plan against a wide range of key uncertainties. Key challenges faced by the project team included:

- Building a robust range of earth models with low resolution seismic and limited well data.
- Finding suitable geologic analogs, including data on input parameters such as object geometries.
- Gaining consensus and buy-in with respect to input parameters and methodologies from a large subsurface team, peers and partners.
- Building the framework, both structurally (i.e., properly modeling a thrust fault in close proximity to the wells) and stratigraphically (i.e., architectural elements that laterally pinch-out).
- Model resolution (vertical and aerial) vs. model size.

Simulation and Results

Field data, laboratory data and analog data were incorporated into a range of reservoir simulation models. The field data included appraisal well logs, cores, 3D seismic, fluid samples, pressure data and drill stem tests.

Experimental Design was used throughout the evaluation to obtain the maximum information with the minimum computational effort. The results from this process facilitated the identification of the key uncertainties and provided direct input into economic models for decision analysis. During each phase of the process key parameters of uncertainty were identified and ranked in terms of project impact. Field development options were evaluated in distinct phases over the full range of uncertainty.

In Phase Two of the evaluation, the pressure maintenance schemes were selected. Crestal gas re-injection with peripheral water injection was chosen for the 17MY reservoir. Crestal gas re-injection only was selected for the 14MY and 16MY reservoirs. These approaches to pressure maintenance deliver an effective full-life gas disposition strategy for the Agbami Field. The facility capacity requirements were also selected during this phase.

In Phase 3 of the evaluation the well count parameter was investigated and the optimum number of 38 wells was selected. Production profiles were generated and presented in terms of P_{10}, P_{50}, and P_{90}. ■

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Biographical Sketches

David Grimes began his career with Texaco in Houston in 1978 and joined ChevronTexaco in 2001 through its merger with Chevron. He is currently assigned as a geophysicist on the Agbami Development Subsurface Team, a part of ChevronTexaco Overseas Petroleum Company's Nigeria/Mid-Africa Strategic Business Unit. In addition to this current development assignment, he has worked international exploration projects in Nigeria and Angola and domestic exploration projects in the Rocky Mountains and West Texas. He began his career in seismic data processing and analysis and worked on projects from around the world. He served on Texaco's Exploration Risk Committee in the year prior to the merger with Chevron. David has a BS degree in mathematics and physics from Stephen F. Austin State University and is currently a member of the SEG. His e-mail is grimesdl@chevrontexaco.com.

Elliott Ginger has worked for ChevronTexaco (via Getty Oil Company and Texaco) since 1981. He is currently the Reservoir Characterization Team Leader for the Agbami Development Subsurface Team. Previous assignments have included 16 years as a reservoir geologist at Getty and Texaco's Exploration and Production Research Center working on reservoir characterization/earth modeling projects on fields in the Middle East, Australia, Guatemala, China, Gulf of Mexico, Alaska, California, West Texas, New Mexico and Alabama. He also spent 1.5 years in Perth, Australia, as a secondee on behalf of Texaco to West Australia Petroleum Pty. Ltd. as a member of the Drilled Resources Team for the Greater Gorgon gas fields, Northwest Shelf, Australia. Elliott has a BS degree in geology from Ohio University and is a member of AAPG.

John Spokes began his career with Texaco in New Orleans in 1981 and joined ChevronTexaco in 2001 through the merger with Chevron. He is currently the Reservoir Engineering Team Leader for the Agbami Development Subsurface Team, a part of ChevronTexaco's Overseas Petroleum Company's Nigeria/Mid-Africa Strategic Business Unit. Previous experience includes 13 years as a reservoir engineer on asset teams working on offshore shelf projects in the Gulf of Mexico. He has worked exclusively on deepwater project teams since 1994. His primary expertise is in the area of reservoir simulation studies in support of appraisal and sanction decisions for major deepwater projects, including Petronius. John has a MS degree in petroleum engineering from Louisiana State University and is a Registered PE in the State of Louisiana. He is also a member of SPE.