

## **Arun-NSO Carbonate Gas Fields, North Sumatra Basin, Indonesia**

Avianto, Rakhmadi (Avi)<sup>1</sup>, I. Wayan (Aris) Widarmayana<sup>1</sup> (1) ExxonMobil Oil Indonesia Inc, Jakarta, Indonesia

The Arun and North Sumatra Offshore (NSO) gas fields are located onshore and offshore respectively, near the northern tip of Sumatra Island, within the prolific North Sumatra Basin hydrocarbon province. The gas reservoirs are Early to Middle Miocene carbonate build-ups on basement horst blocks associated with Paleocene-Oligocene rifting. In the last stage of carbonate development, several sea-level falls resulted in enhanced permeability within the upper reservoirs. Middle-Late Miocene marine shales seal the reservoirs.

The Arun giant gas field was discovered in 1971 and came on stream in 1975 with gas supply mainly to Arun LNG. This field is defined by eighteen 2D seismic lines and one hundred eighteen wells. Hydrocarbon recovery is extremely high, approximately 15.0 TCF of dry gas produced from an OGIP of 16.8 TCF. Reservoir management of the field has changed focus in response to the highly depleted reservoir pressure and falling production rates. An infill drilling campaign in 2002-2003 using big bore wells was successfully implemented and significantly increased field deliverability. The NSO gas field was discovered in 1972 and production commenced in 1999, with the gas used to supply Arun LNG. The field is well defined by a 3D survey and sixteen wells. The reservoir contains north-south oriented spires and walls of tight dolomite that may act as lateral baffles resulting in lower reservoir connectivity. The highly permeable and compressive reservoir is developed through horizontal wells with ~300 ft stand-off from the GWC. The OGIP for the NSO field is 2.7 TCF (dry gas).

## **The Perseus Field, North West Shelf -- a Sleeping Beauty Awakes**

Reding, Etienne<sup>1</sup>, Steve Abernethy<sup>1</sup>, Dave Boardman<sup>1</sup>, Peter Carter<sup>1</sup> (1) Woodside Energy Limited, N/A, Australia

The Giant Perseus field is operated by Woodside on behalf of the North West Shelf venture partners and it is the largest single gas accumulation supplying the LNG plant in Karratha, Western Australia.

The first penetration in the Perseus accumulation in 1972 was the North Rankin-4 well, but the full size and potential of the field was only recognised after the start of production of the NRA22 deviated well, drilled in 1991 from the North Rankin facility and after drilling of 6 appraisal wells in 1995-1996. Two more production wells were added in 2001, increasing production four-fold and confirming the huge potential of the Perseus reservoir. The new high quality Demeter seismic survey acquired in 2003 has resulted in a new seismic interpretation that reveals the structural and stratigraphic complexity of the fluvio-deltaic reservoir and helping to improve mapping of the drainage pattern. The interpretation was integrated into static and dynamic models, which were calibrated with historical production and pressure data. The models have highlighted the need to drill wells across all compartments to achieve an optimal and uniform drainage across the whole field.

In order to access poorly drained compartments, 6 additional wells will be drilled in 2006, 3 wells from the North Rankin platform and 3 subsea wells tied back to the Goodwyn production facility. This latest phase of development and later compression over the North Rankin B facility (NRB) will allow the Perseus Field to produce the majority of the North West Shelf Venture gas post-2007.

## **Stratigraphic Controls on Production Behaviour: M1-Jintan Carbonate Gas Fields, Offshore Sarawak**

Singh, Navpreet<sup>1</sup>, Paul Faehrmann<sup>1</sup>, Rani Koya<sup>1</sup>, Frank Wolters<sup>1</sup> (1) Shell Asia Pacific Exploration & Production, Sarawak, Malaysia

This paper offers interesting insights on the stratigraphic controls/ deposition architecture resulting in baffles which impact production behavior on the M1 and Jintan carbonate gas fields of the Mega Platform, Offshore Sarawak, Malaysia. Fields of the Mega Platform were developed assuming a depletion drive. However, production data suggests a strong aquifer drive, with low recovery factors. In addition, the geological control on production behavior was thought to be simple i.e flow tanks with little or no baffling.

Issues relating to the complex nature of these carbonate reservoirs include:-

1) In early 2004, the horizontal well M1-110S1, located some 30 ft below the top reservoir, watered out unexpectedly after two years of high production offtake rates. The watering out of M1-110 can be explained by a different reservoir architecture and the reduction in kv/kh (baffling) across boundaries within the aquifer. The low vertical permeability caused water to bypass gas, resulting in water production in M1-110S1

2) The early stage of the development of the Jintan field in 2004 (4 horizontal wells high up in the structure) saw a drastic drop in pressure and offtake within a few months of production. This was due to baffling in the underlying transgressive limestones, which reduced vertical pressure communication

Tools and work processes employed to overcome these issues include:-

- 1) Semi-regional/inter-field correlation
- 2) Acquisition of additional core and a re-look at the existing core stratigraphy
- 3) Usage of mini-permeability data for kv/kh
  - 4) OBC 4C 2D seismic for imaging internal reservoir architecture (M1)
  - 5) Generation of a detailed semi -regional static and dynamic model for history matching.

## **Reservoir Modelling of a Distal Isolated Carbonate Platform, Offshore Sarawak - Stratigraphic Compartmentalisation and Implications on B11 Field Development**

Coca, Spencer<sup>1</sup>, Miltos Xynogalas<sup>1</sup>, Kumareson Paranthaman<sup>1</sup>, Benedict Polycarp<sup>1</sup> (1) Sarawak Shell Berhad, Miri, Malaysia

Detailed geophysical and reservoir geological studies triggered by development drilling surprises and unexpected production behaviour of a large carbonate gas field, offshore Sarawak, unravelled stratigraphic complexities caused by a

combination of syn-depositional tectonics and high-frequency sea level changes. As a result, a novel depositional model for distal, isolated carbonate platforms situated along the northwestern Borneo palaeo-shelf margin emerged. Extensive use of seismic volume interpretation was employed to unravel the heterogeneous intra-carbonate architecture. In this respect, spectral decomposition and a combination of elastic/constrained-sparse-spike/stochastic seismic inversions were used to map in 3D the distribution and geometry of depositional sequences. Petrophysical core analysis revealed a distinct electric log response for each rock fabric present in the build-up. Based on these facies-dependent porosity vs. sonic travel-time relationships, seismic velocity and acoustic impedance models were used to generate 3D-carbonate facies reservoir models that were successfully validated by subsequent infill drilling. As a result, stratigraphic compartmentalisation was proven to be present in Central Luconia carbonate build-ups. With the newly developed reservoir modelling workflow production history matching was easily achieved and the unexpected wells decline understood. This new subsurface understanding is in contrast to earlier and widely used models whereby Central Luconia carbonate were interpreted as simplistic 'layer-cake' type tanks that do not require an in-depth understanding of the subsurface in order to be successfully developed.

### **Bayu-Undan – From Stratigraphy to Dynamic Simulation**

Krieger, Frank W.<sup>1</sup>, David R. Mabee<sup>2</sup> (1) ConocoPhillips Australia Pty Ltd, West Perth WA, Australia (2) ConocoPhillips Australia Pty Ltd, West Perth WA, Australia

The Bayu-Undan Field lies in the Timor Sea to the NW of Australia and is a world scale retrograde gas-condensate accumulation.

The hydrocarbon bearing reservoir section comprises the Bajocian to mid Callovian Plover Fm deposited in a tidally influenced, fluviially dominated delta system. Overlying this is the mid-Calloviaian to Oxfordian Elang Fm which is made up of five progradational pulses within an overall transgressive system culminating in the drowning of the delta system.

Critical to understanding both GIIP and the dynamic behaviour of the field is the distribution and connectivity of the reservoir and the interplay between erosion and structural position.

Fieldwide correlation in the Elang Fm is relatively straightforward with large shale breaks between progradational pulses when good quality sands were deposited. The Plover Fm is more problematic due to the absence of detailed biostratigraphic markers in a relatively barren fluvial section.

The desire to produce a realistic, flow unit based simulation model for the Plover, where >70% of recoverable resources lie, has resulted in the use of detailed ichnofacies and chemostratigraphy to help constrain a carefully considered sequence stratigraphic approach.

The new stratigraphic framework for the Plover Fm coupled with an accurate erosional model for the Elang Fm allows robust characterization of GIIP. However, more importantly, it allows an assessment of the impact on ultimate recoverable resources, of reinjection of lean gas, and of water production; especially when considered in conjunction with rigorous fault modelling.

### **Bayu-Undan – Full Field Reservoir Modelling in a Re-Cycled Gas Reservoir**

Lozada, Tito<sup>1</sup>, Greg Thiesfield<sup>1</sup>, Dag Sanner<sup>2</sup>, David R. Mabee<sup>3</sup> (1) ConocoPhillips Australia Pty Ltd, West Perth WA, Australia (2) ConocoPhillips Australia Pty Ltd, West Perth WA, Australia (3) ConocoPhillips, West Perth WA, Australia

The Bayu-Undan Field lies in the Timor Sea to the NW of Australia and is a world scale retrograde gas-condensate accumulation.

Bayu-Undan produces 1 bcf/day of raw gas and 110,000 bpd of liquids. Up to 950 MMscf/day of lean gas is re-injected into 4 wells. Partial gas export to the Darwin LNG plant commenced in 2006. Following the plant ramp up, LNG exports will be about 3 million tonnes per annum (Mtpa).

Initial development drilling at Bayu-Undan proved challenging, with significant changes to the field development plan required. Reservoir modelling and the analysis of early key performance data were critical to successfully changing the development plan. The main changes were the implementation of big bore wells, semi-open-hole completions and changes to the bottom-hole locations. The early acquisition of performance data including bottom-hole pressures provided an insight into the expected dynamic behavior.

The Bayu Undan reservoir simulation model has been history matched based on a theory of conductive faults. A fault damage zone analysis has been performed leading to an enhanced permeability system associated with certain fault directions.

To maximise recovery and sustain the current rate many challenges exist requiring effective reservoir management. The main challenges relating to maximizing Net Present Value (NPV) of the Bayu-Undan field are: (1) maximization of the sweep efficiency and management of premature lean gas breakthrough due to high permeability conduits, (2) total injection capacity of recycled gas, and (3) delay of water breakthrough.

### **Uncertainty Reduction through Development in the Vorwata Field, Tangguh Project**

Davis, Neil<sup>1</sup>, Harso Isworo<sup>1</sup>, Festarina Festarina<sup>1</sup>, Curtis Bennett<sup>1</sup> (1) BP Indonesia, Jakarta 12520, Indonesia

The Vorwata gas field forms the cornerstone of the initial Tangguh LNG project. It was discovered in late 1996 in Berau Bay in the Bird's Head Area of Papua Province, Indonesia. The field will supply dry gas to the Tangguh LNG facilities which will start up in 2008. The initial Vorwata development will exploit gas at 1.46 Bcf/day using two platforms, two pipelines and up to 15 initial development wells.

Key reservoir uncertainties prior to development include reservoir connectivity, distribution of perched water and reservoir thickness/permeability. Uncertainties result from poor seismic image quality and lack of production data from the basin.

Initial wells are each projected to deliver upto 270 mmscf/day if well-connected, high quality reservoir away from perched water is encountered. A program was designed to reduce development uncertainties and to optimise initial well requirements.

Initially, a risk analysis was developed to measure the impact of reservoir uncertainty on well number required to assure gas deliverability.

A buried 4C OBC seismic was acquired in the core part of the field to improve understanding of perched water, reservoir thickness and permeability. Interference tests are planned during initial field development to address reservoir connectivity concerns. The LNG development requires early gas from a single well for fuel and commissioning.

### **Reservoir Characterization of the Jansz Gas Field, North West Shelf, Australia**

Jenkins, Chris C.<sup>1</sup>, Wayne J. Mudge<sup>1</sup>, Michael A. Williams<sup>1</sup>, Peter N. Glenton<sup>1</sup>, John G. McPherson<sup>1</sup>, Andrew A. Mills<sup>1</sup> (1) ExxonMobil, Melbourne Vic, Australia

The Jansz Gas Field<sup>1</sup>, discovered by the Jansz-1 well in 2000, lies in the Carnarvon Basin 250 km offshore from the northwest coast of Australia. The field covers approximately 2000km<sup>2</sup> in water depths ranging from 1100 to 1400 meters. The gas reservoir is an Upper Jurassic lower-shoreface clay-rich sandstone, up to 50 meters in thickness, approximately 2800 meters sub-sea. Jansz gas is part of the Greater Gorgon deep water gas assets and is a focus for development activity to meet an expanding LNG market.

A detailed reservoir characterization study has provided the geocellular models required for reservoir simulation and optimized input to the field development plan. An integrated approach to subsurface reservoir analyses has allowed a range of reservoir uncertainty to be investigated, using a variety of geological scenarios.

A field appraisal program, including a 2900 km<sup>2</sup> 3D seismic survey, three wells with 150 meters of core in the reservoir interval and a production test, was conducted from 2001-2005. The primary objective of the program was to determine the reservoir architecture and quality of the Upper Jurassic sandstone.

A chrono-stratigraphic framework for the reservoir interval was constructed using the 3D seismic interpretation, wireline logs and biostratigraphic data. Several 3D geologic models were built using this framework. Models were populated with lithofacies assemblages and porosity values using well control, geological concepts and a 3D acoustic impedance volume.

Permeability and water saturation were assigned using the lithofacies assemblage and porosity models, calibrated to wireline log and core data.

<sup>1</sup> Jansz joint venture participation: WA-18-R, Mobil (25% operator) & Chevron (50%) Shell (25%); WA-25-R & WA-26-R, Chevron (50% operator), Mobil (25%), Shell (12.5% & BP (12.5%)

### **Late Triassic Pre-Rift Stratigraphy of the Gorgon Gas Field: Establishing Appropriate Depositional Analogues as Constraints for Geologic Modelling**

Montgomery, P.<sup>1</sup>, N. Miller<sup>1</sup>, A.C. Villella<sup>1</sup>, R. Root<sup>1</sup>, J. Roche<sup>1</sup>, T. Munckton<sup>1</sup> (1) Chevron Australia Pty Ltd, Perth, Australia

Gorgon is a giant gas field owned by a joint venture operated by Chevron (50%), in partnership with Shell (25%) and ExxonMobil (25%). Gorgon will be a subsea development in 200-300m of water which, in conjunction with the neighbouring Jansz gas field, will feed a two train LNG facility 70km distant on Barrow Island.

Gorgon was discovered in 1980 with the Gorgon-1 well, which encountered a 500m gross gas column in Triassic sandstones. The reservoir comprises a thick stack of Triassic fluvial channel units varying from high net-to-gross intervals containing coalescing channel belts to lower net-to-gross intervals with more isolated channels. The reservoir has been penetrated by eight wells and over 500m of core has been recovered. A sequence stratigraphic model has been used to subdivide the reservoir into twelve zones within an overall transgressive sequence. Each zone is a division within a series of sequences comprised of a basal erosion surface overlain by amalgamated fluvial sheets followed by a heterolithic interval containing isolated fluvial sand and terminated by an erosion surface. Each sequence can be interpreted as a fluvial system's response to a base-level fall and erosion, followed by increasing then decreasing rates of base-level rise, eventually terminating in base-level fall and erosion surface. A high resolution base-level curve for the Gorgon field based on gamma-ray logs from the eight Gorgon delineation wells has been proposed and used to determine the appropriate depositional analogues employed during Gorgon field geologic modelling.

### **The Ichthys Giant Gas-Condensate Field**

Ban, Shinsuke<sup>1</sup>, Graham M. Pitt<sup>1</sup> (1) Inpex Browse, Ltd, Perth, Australia

The Ichthys giant gas-condensate field is located in the northern Browse Basin of the Australian North West Shelf. The field lies 220km offshore, in 260-280m water depth. The first well drilled in the field area was the untested Brewster-1A (1980). In 1998 Inpex Browse, Ltd. (INPEX) was awarded the WA-285-P block, drilling 3 wells in 2000-2001. Gas discoveries were made in the Brewster Member of the Upper Vulcan Formation and in the Plover Formation. Three follow-up wells were drilled in 2003-2004.

The Brewster Member (*K. wisemaniae*, Berriasian), is a thick sequence of high NTG sands, interpreted as mid-slope grainflows on a deep-water ramp. The trap is a broad drape structure with mainly dip closure, occupying about 400km<sup>2</sup> within WA-285-P. It contains a wet gas column of about 200m and is full to spill.

The Plover Formation consists of fluvial to paralic sands, with interbedded claystone and coal, of mainly *C. turbatus* (Toarcian – Bajocian) age. The nature and distribution of interlayered extrusive basaltic volcanics is vital to the determination of the net reservoir distribution. The Plover trap is defined by dip closure and faulting and the trap volume is internally faulted, but not compartmentalised. Like the Brewster Member, a gas column of about 200m is present in the Plover Formation and the closure appears to be full to spill.

The Plover gas is drier than the Brewster gas. The pools are not in communication but both are currently considered to have a Plover source. Thin gas-charged sands are present between the two main reservoirs.

The Ichthys gas-condensate field has the potential to be a major offshore Western Australian project, and INPEX is now working towards the commercialisation of this large resource.