Maari-1/1A - Results and implications for development

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Abstract

Shell Todd Oil Services (STOS) took over as operator of PEP 38413 in 1997 when Shell Petroleum Mining and Todd Petroleum Mining farmed into the Cultus Petroleum-held licence located 80 km offshore Taranaki.

Technical and commercial evaluation by STOS identified several key changes to previous understanding. The most important change was increase in oil volumes for the Moki sands due to re-interpretation of the oil-water contact together with upside realisation in structure due to shallow gas effects on 2D seismic.

Well Maari-1 was drilled in December 1998 to assess the Miocene Moki and M2A sands and the Eocene Kapuni sands. Following sufficient hydrocarbon and permeability indications, the well was sidetracked as a 654 m horizontal well (Maari-1A) to test for commercial oil production rates. The well flowed 4400 bopd and a significant sampling programme was completed to characterise the reservoir fluids.

Major improvements in the understanding of the Maari prospects were:

- confirmation of the deeper OWC in the Moki sands;
- confirmation of a laterally continuous reservoir architecture;
- a production test rate much higher than previous tests;
- thickening of the M2A sands towards the west;
- discovery of an 8 m gas column with 33 m oil column in the Kapuni sands; and
- increased number of options for profitable recovery of waxy oil.

Follow up work on Maari showed that economic development of Maari is very likely feasible and attractive. The preliminary field development concept is based around an FPSO with subsea multilateral wells and water injection. However, key uncertainties remain and will be addressed during development planning. A 3D seismic program was completed in 1999 to delineate further upside in the licence and facilitate further development studies.

The Maari appraisal program has met with success and was characterised by good multi-discipline teamwork by STOS and Joint Venture partners to assess and resolve major uncertainties in a cost-effective manner.

Introduction

Offshore exploration licence PEP 38413 is located some 80 km southwest of the Taranaki coast (Figure 1). The Maari Field is an anticline located in the eastern half of the licence, and contains oil in the Miocene M2A and Moki sands, and Eocene Kapuni sands (Figure 2). This paper will address the exploration history within the licence, the major uncertainties were resolved with respect to well rates, oil in place volumes, reservoir architecture and upside in the Kapuni and M2A sands, the results of the evaluation campaign conducted by STOS during drilling and testing of Maari-1/1A, and will present an overview of the progress to date on development planning.

PEP 38413 exploration and history

Shell BP Todd Oil Services first found oil in the current licence at Maui-4 in 1970 and the subsequent history is shown in Figure 3.

In 1997 Shell (Petroleum Mining) Co. Ltd and Todd Petroleum Mining Co. Ltd agreed to farm in to PEP 38413 by contributing to the exploration/appraisal well Maari-1 thereby earning 35% and 15% interests from Cultus Petroleum NL respectively, whilst appointing STOS as Operator. Shell and Todd have subsequently increased their equities to 49% and 21% respectively, with Cultus (now OMV Australia) now holding the remaining 30% equity.

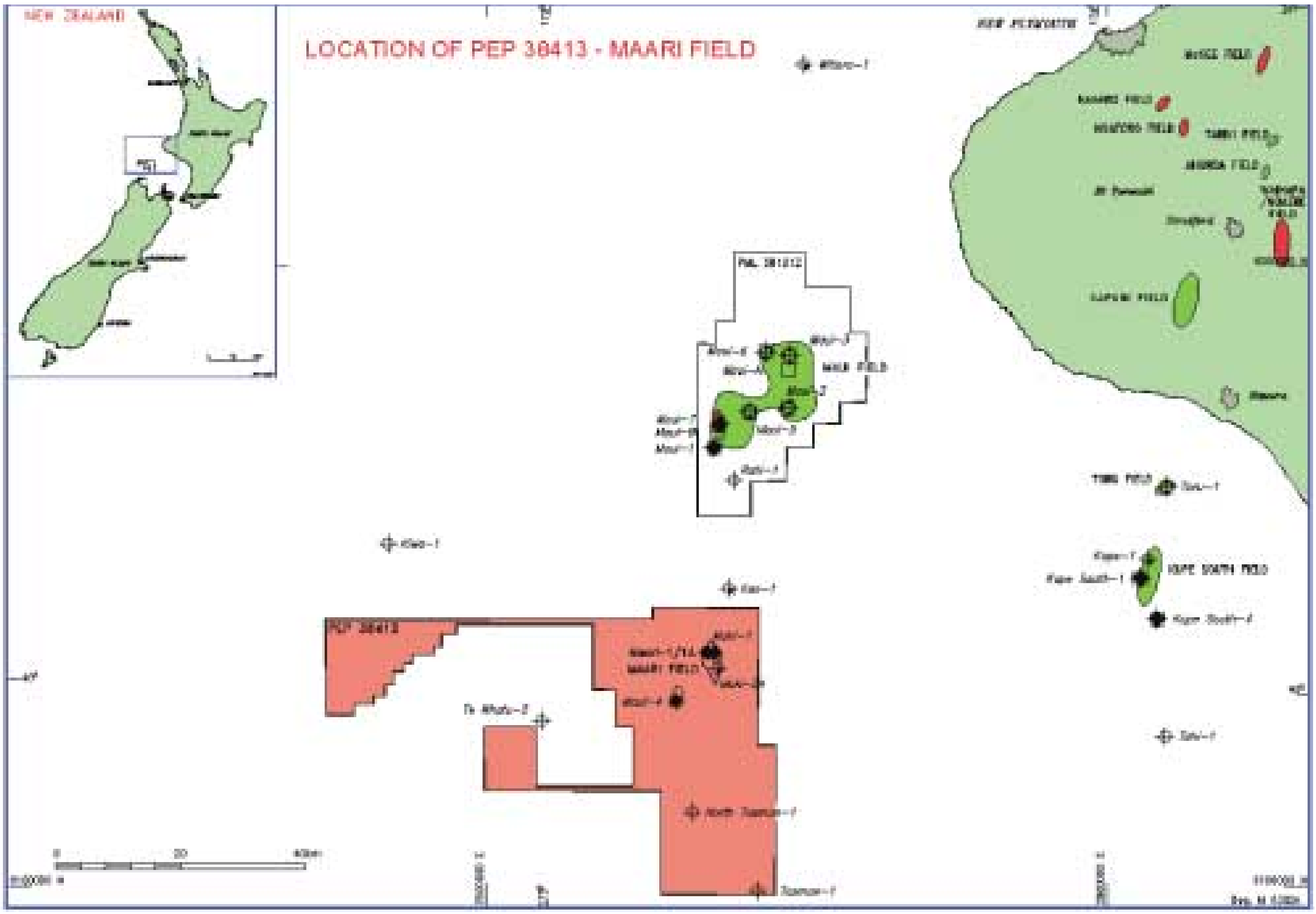

Figure 1: Location of PEP 38413 and Maari Field.

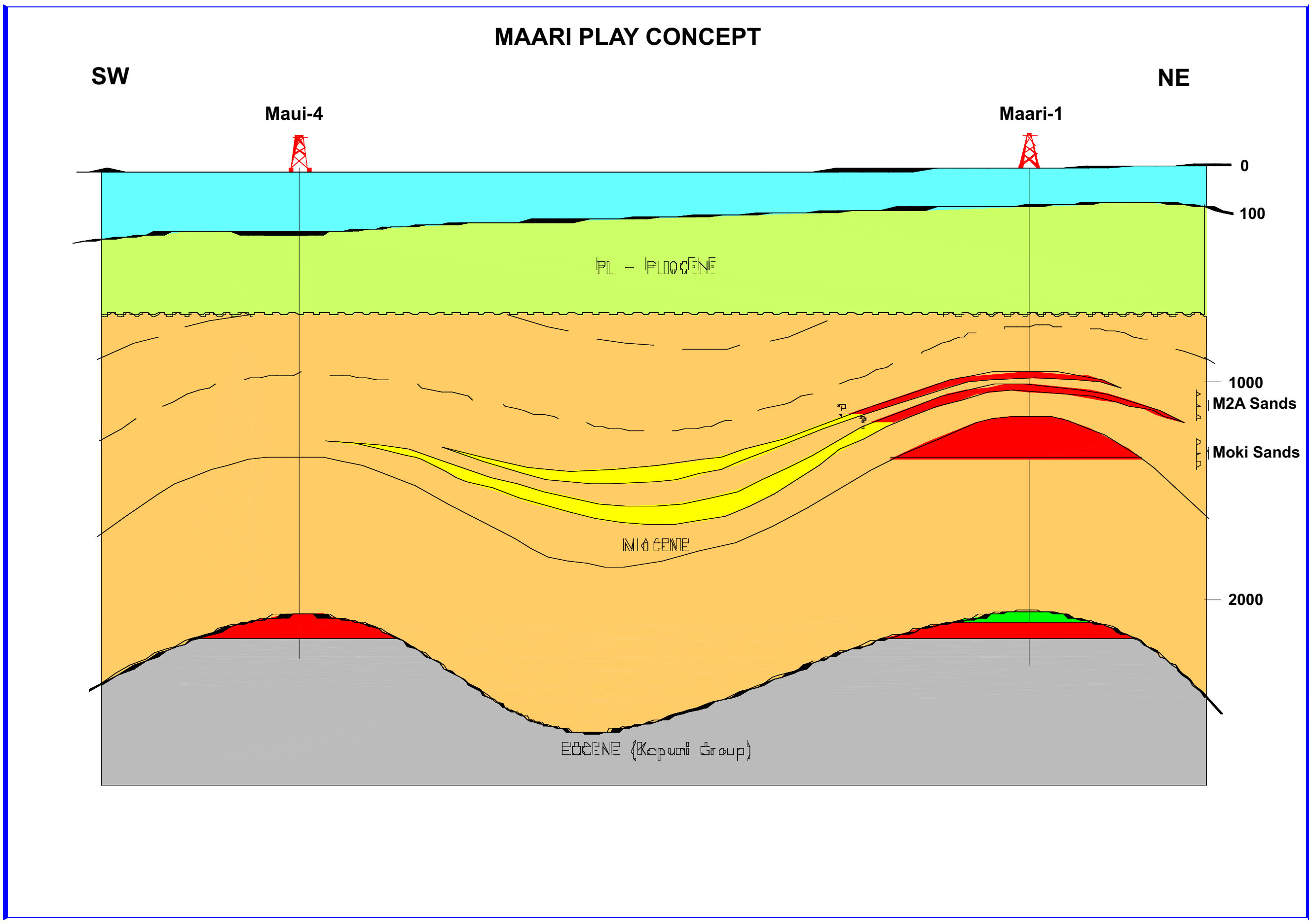

Figure 2: Cross-section of Maari and Manaia structures.

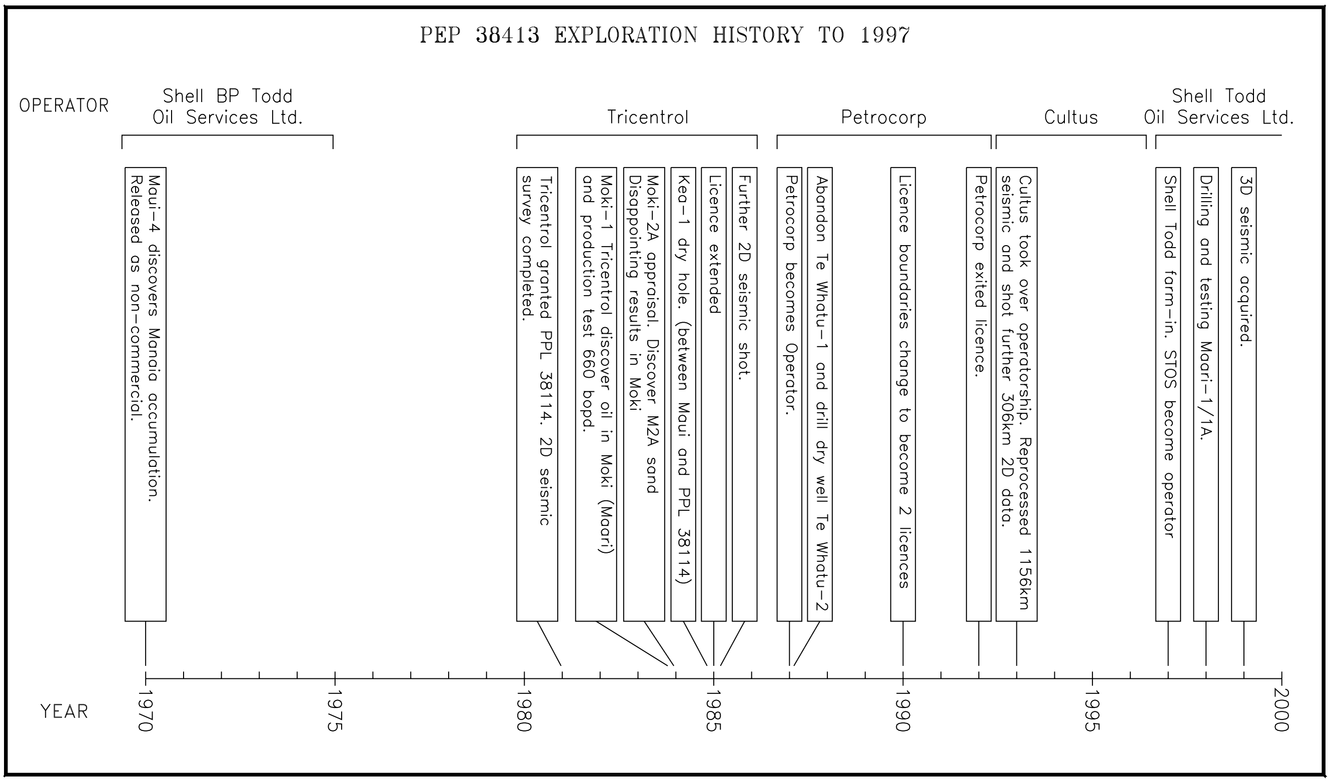

Figure 3: PEP 38413 timeline (1970-1999).

Maari-1 objectives

Three reservoir intervals were the focus of the Maari exploration and appraisal campaign. STOS revisited the work done by previous operators and concluded that the oil in place volumes in the Moki reservoir were significantly larger than previously recognised. The Maari field was evaluated to contain 175 million bbl oil within the marine sands of the Moki Formation, possibly 95 million bbl within the shallower M2A sand and possibly 16 million bbl attic oil in the Kapuni Group (all volumes stock tank oil initially in place - STOIIP).

Moki sands

Reservoir modelling indicated that 1000 m horizontal well penetrations through the Moki Formation could produce at initial rates of up to 5000 bopd.

The main objective of the drilling campaign was to prove commercial production rates from a horizontal section through the Moki Formation. Poor well deliverability was considered the biggest subsurface risk to the economic development of the Maari Field.

The second major uncertainty was the geological model with respect to reservoir quality across the Moki Field. A depositional model was proposed that suggested sheet sands deposited in ponded mini-basins analogous to many Gulf of Mexico reservoirs (Prather et al. 1998), with the best quality sands contained in the uppermost 10-20 m of the formation. Both this geological model and these high rates needed to be confirmed by Maari-1/1A before possible field development could be considered.

Thirdly, there was a large range in the STOIIP estimates for the Moki Formation (100 million bbl up to 200 million bbl). This was mainly due to:

- 54 m uncertainty in the depth of the oil-water contact, similar to the depth uncertainty of the fault leak point in the south of the field; and
- shallow gas effects on seismic data, which were believed to give a pessimistic view of the Moki structure by depressing the crest of the structure.

M2A Sands

Five pressure measurements from well Moki-2A indicated 5-8 bar overpressure in the M2A sand. However, no trend could be determined from these points to differentiate oil from water. The M2A sand was cored in Moki-2A and showed excellent reservoir properties.

Evaluation of the 2D seismic showed that amplitudes increased to the south-west of the Moki-1 location at the M2A horizon. A depositional model of a thickening lobe of sand into the paleo-low between Moki-1 and Maui-4 was suggested and supported by seismic modelling and analogues from the Gulf of Mexico.

If confirmed hydrocarbon bearing, it was recognised that the M2A sand could add significant upside to the Maari Field. Therefore another objective of this well was to test the depositional model for this sand and to determine its fluid content.

Kapuni sands

A third target of the proposed well was potential attic oil in the Kapuni Group up-dip from Moki-1. Moki-1 was evaluated as containing residual oil saturations in the Kapuni Group. However, there were indications in Moki-1 logs that the top two meters may be at the base of a transition zone. Fluorescence was detected during coring of the Kapuni Group. In order to narrow the uncertainty with respect to this potential attic oil, the well was planned to penetrate the top Kapuni 12 m shallower than the water-up-to of Moki-1. Total depth of Maari-1 was chosen as being 150 m into the Kapuni Group in case the oil saturation evaluated in Moki-1 was in fact moveable or in case separate accumulations existed between intra-formational Kapuni Group seals.

Maari-1/1A

Drilling Maari-1/1A

The vertical well Maari-1 was spudded on the 30th of October 1998 with the semi-submersible rig Sedco 702. The well was located at the crest of the Maari structure about 800 m west of the discovery well Moki-1 (Figure 4).

The Moki Formation was encountered at 1290 m TVss and evaluated to contain oil. The presence of a shale across the oil-water contact, prevented range in the oil-water contact being minimised to less than 10m uncertainty. 66.5 m of core was cut over the oil bearing section of the Moki Formation.

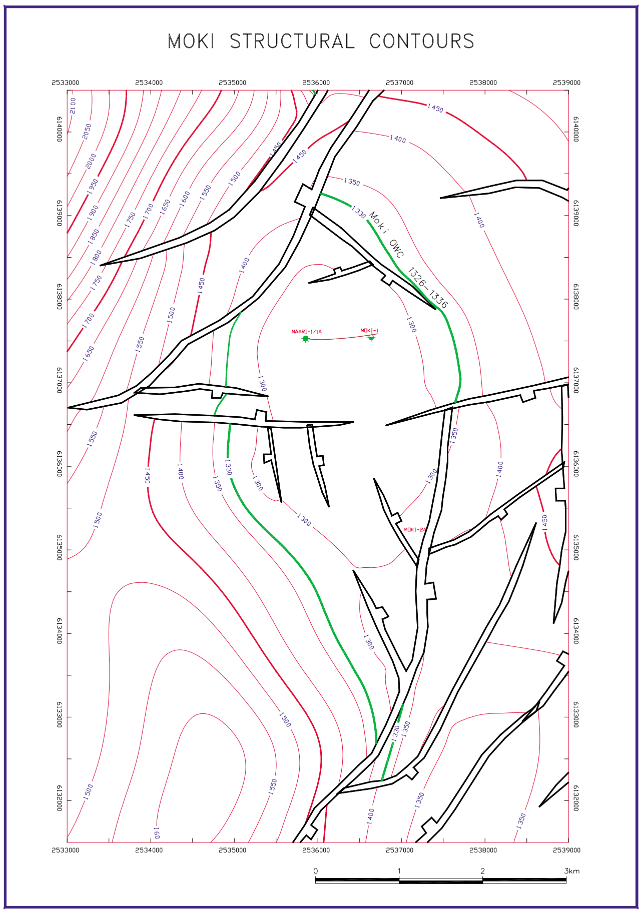

Figure 4: Moki structure map.

A significant wireline evaluation programme was completed which included:

- STAR – SimulTaneous Acoustic and Resistivity Sensor for imaging the borehole;
- Offset VSP (vertical seismic profile) for steering the horizontal sidetrack;
- Numar MRIL, nuclear magnetic resonance tool; and
- RCI Pressures and live fluid samples from the Moki, Kapuni and M2A sands.

Figure 5 shows (from left to right) standard logs, interpreted porosity and saturations, core and MRIL permeabilities and sedimentary interpretation of the core described by IGNS.

The shallower secondary objective, the M2A unit, was found to be oil-bearing with high porosity's (~26 %) and high oil saturations (~70 %). This result confirmed the thickening of these sands to the south-west of Moki-1. The deeper secondary objective, the Kapuni Group sands encountered an 8 m gas column and a 33 m oil column, confirming up-dip oil potential from Moki-1.

Maari-1 was plugged back and sidetracked as Maari-1A to drill horizontally through the Moki formation. Maari-1A drilled 654 m of formation measured from the 9-5/8" casing shoe to TD, of which 563 m was oil bearing. The M2A sand was also intersected in the build up section of the sidetrack, indicating it to be laterally extensive. The schematic of the sidetrack is shown in Figure 6.

The horizontal sidetrack encountered formation almost exactly as predicted. This confirmed the good correlation between Maari-1 and Moki-1, the lateral extent of the marine sands and the unfaulted nature of the crest of the structure.

Maari-1A was completed and then production tested (see below). The well was suspended on the 25th of December 1998 and the Sedco 702 drilling unit moved off location on 27th of December 1998.

Maari-1A Production Test

Maari-1A was completed with a 7" slotted liner along a 654 m horizontal section of 8 1/2" hole in the Moki sands. The well was unloaded using nitrogen and coil tubing and flowed 37°API waxy oil at a maximum rate of 4370 bopd through a 181/64" choke with a GOR of 315 scf/bbl at a THP of 285 psi. This is considerably more than the 660 bopd that was produced from the vertical well Moki-1.

These higher rates have proven the concept of developing the Maari field with horizontal wells and have lifted the field out of the uneconomic category.

The well test was not specifically designed to derive reservoir properties as the well would have been required to be shut-in for much longer periods to allow reservoir pressure build-

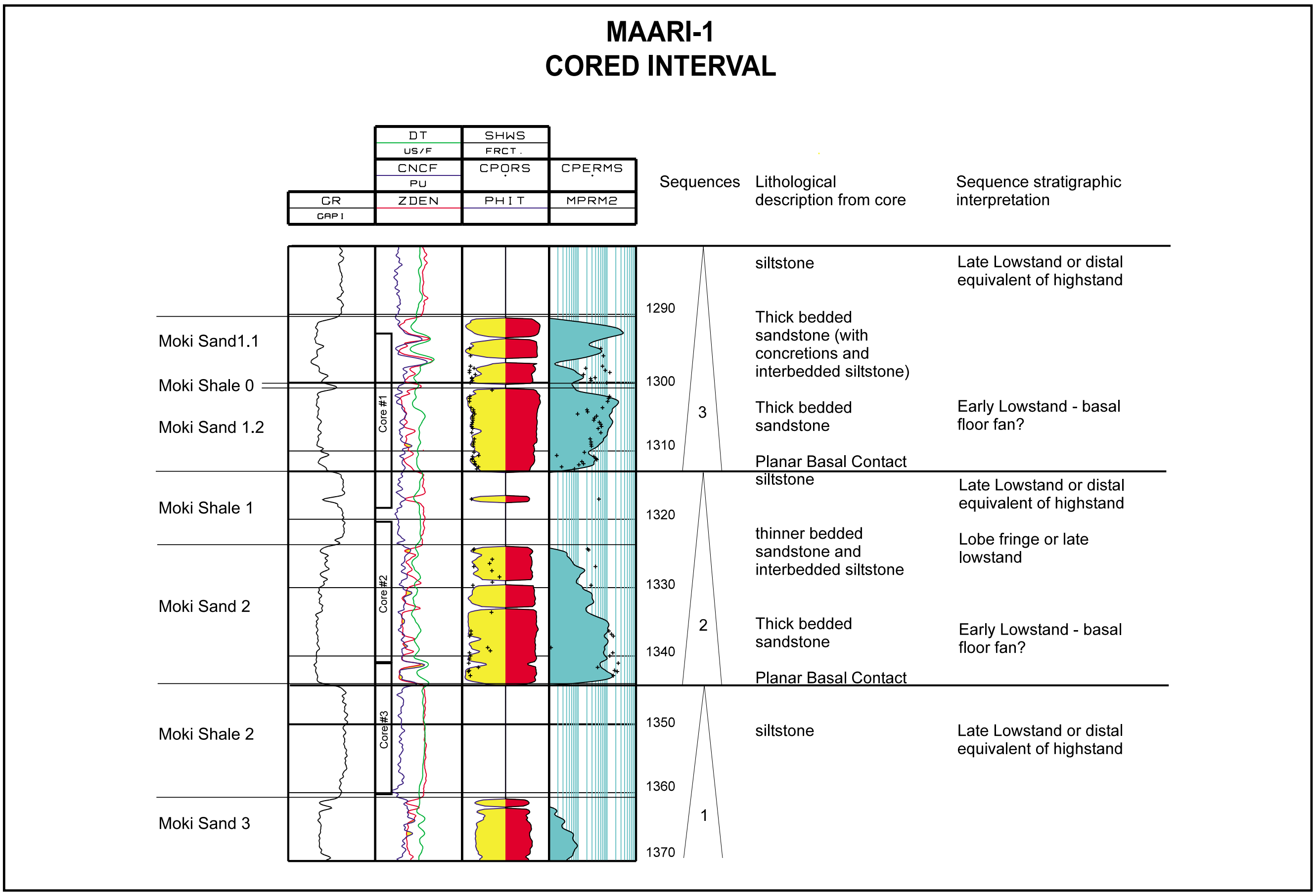

Figure 5: Maari-1 composite well logs and core description over the Moki sands.

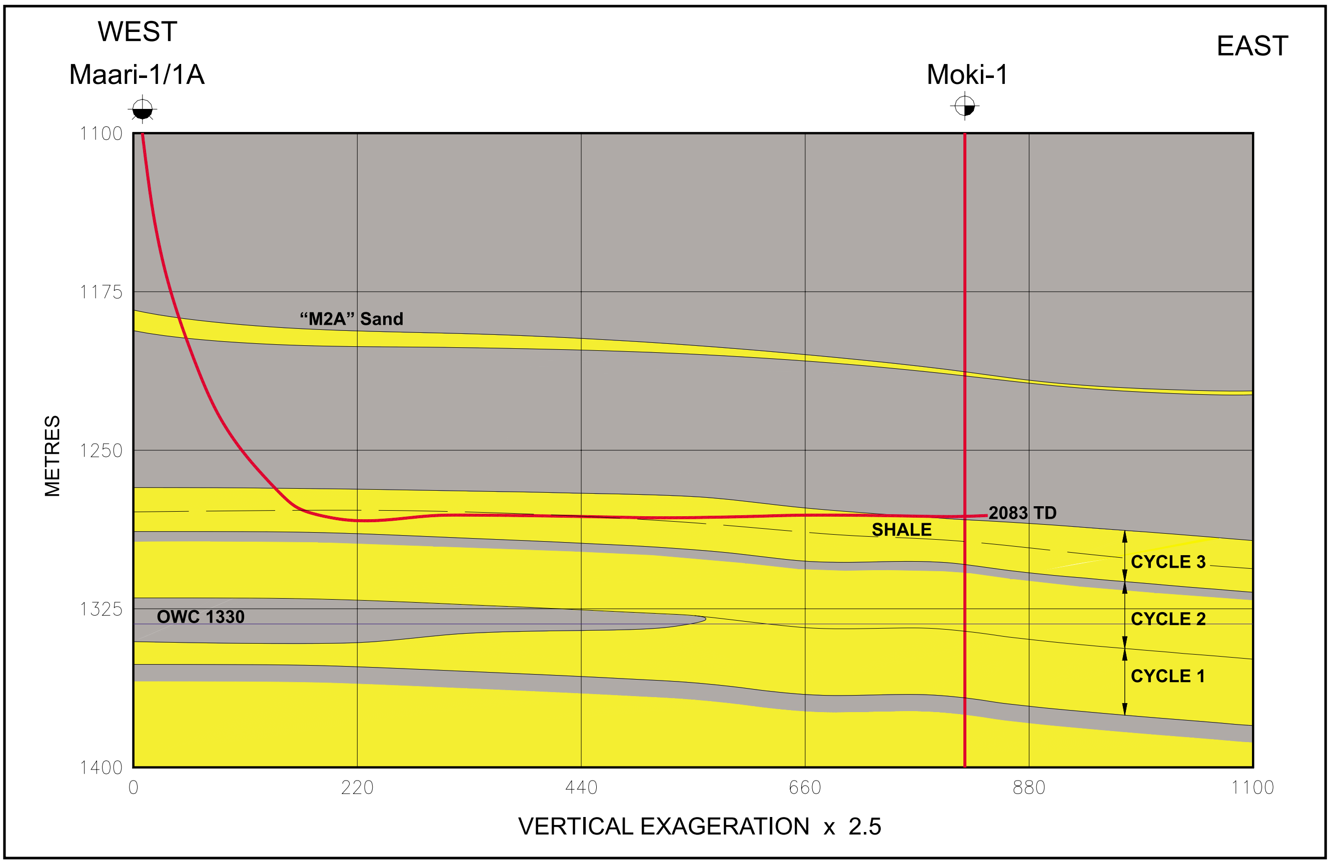

Figure 6: Moki sidetrack schematic.

up. Nevertheless, from the well test analysis, the average permeability was estimated to be around 40 to 60 mD. This is in good agreement with the core derived permeability.

Another interesting insight from the well test analyses was that it is likely that only part of the wellbore was contributing to flow. This suggests that after further clean-up, flowrates greater than the 4370 bopd could be achievable.

Fluid analysis

Live downhole samples of Moki, M2A and Kapuni fluids collected during drilling and surface samples from the production test were sent for analysis. The focus of the lab work, in addition to PVT phase behaviour studies, was to characterise the waxy nature of the Maari crudes and to help evaluate ideas for field developments. This was done by drawing on Shell Oil's experience in the Gulf of Mexico and state-of-the-art wax simulation software.

Maari crudes fit the Taranaki mould in displaying a land plant origin profile for paraffin distribution with a high level of wax components at carbon number 40 plus. Viable methods of mitigating the downhole risk arising from wax (and possibly asphaltene) deposition and the low temperature and pressure in the Moki and M2A sands were assessed.

The PVT studies showed that M2A and Moki oils were slightly undersaturated at approximately 50°C and 130 bar, while the deeper Kapuni oil was saturated. The downhole samples provided more accurate and comprehensive fluid property data than previous samples and analysis. The downhole samples were also tested for solids precipitation. The three crudes have similar moderate pour points and cloud points (~24°C and ~45°C respectively).

Wax studies show that deposition in the production tubing, flowlines, risers, and subsea pipelines can be avoided or controlled at an acceptable cost. Recovery using gas lift was successfully modelled, which provides a viable alternative to Electrical Submersible Pumps. Although the low downhole energy makes artificial lift necessary, it is helpful in significantly reducing the risk of asphaltene precipitation.

A preliminary screening of scaling tendency and water compatibility revealed no major risks, however the quality of these samples was very poor due to significant contamination by mud filtrate.

Development planning

Following the Maari-1/1A drilling, subsurface study work was able to be further advanced and a range of field development options identified.

Subsurface

The internal Moki reservoir architecture consists of correlatable coarsening upward sand/shale cycles, averaging 20 m thick each, occasionally cut by shale filled channels. This lateral continuity is considered ideal for development with horizontal wells. The porosity within the static reservoir model is shown in Figure 7 with wells Moki-1, Moki-2A and Maari-1/1A.

A subsurface review of Moki was completed, updating volumetrics and incorporating the results into Shell proprietary reservoir modelling packages GEOCAP/MORES. The assessment showed that water injection would be required to increase recovery and that lateral reservoir character, away from control points Moki-1, Moki-2A and Maari-1/1A, had a major impact on recovery factors. An aggressive development using multilateral wells and water injection is envisaged for the Moki reservoir.

The Kapuni sands internal reservoir architecture comprises stacked fluvial channel sands. A quick look evaluation of recovery from the Kapuni Group has been made using correlation for recoveries from horizontal wells in coning situations. This used oil properties from Maui-4 and the mapped structural geometry at Maari and indicates that a recovery of 15% of STOIIP should be achieved.

Ranges of STOIIP and Recovery are shown in Table 1 by reservoir unit.

Development concepts

A range of field development options is possible for Maari. The current "base case" is a standalone FPSO with subsea wells. However this is not the final decision and many other alternatives are available, ranging from converting semi-submersibles, to using second-hand platforms, to achieving synergies with the nearby Maui Field infrastructure. Some of these concepts are shown in Figure 8.

Development concepts centre on the following building blocks.

- Production wells in the Moki Formation are multilateral wells (two horizontal lateral branches from each well). Further upside exists to use very long horizontal wells in place of more complex multilateral wells.
- Water injection wells are required in the Moki Formation, and may be required in the M2A formation.
- Drilling will most likely be performed from a central location, however subsurface targets far away (>5km) may be tied back using subsea tiebacks.
- Production units may be FPSOs, providing facilities for processing, storage, offloading and water injection. Semi-submersible FPUs may also be used that process fluids but then export via a pipeline or to shuttle tankers.
- Subsea connection systems will be either tied back to central manifold with multiphase flow metering (FPSO concepts), or use direct vertical access risers (wellhead platforms or semi-submersible floating production units).
- Gas export may be either via existing Maui infrastructure (if commercially attractive) or involve re-injection into shallower reservoirs.

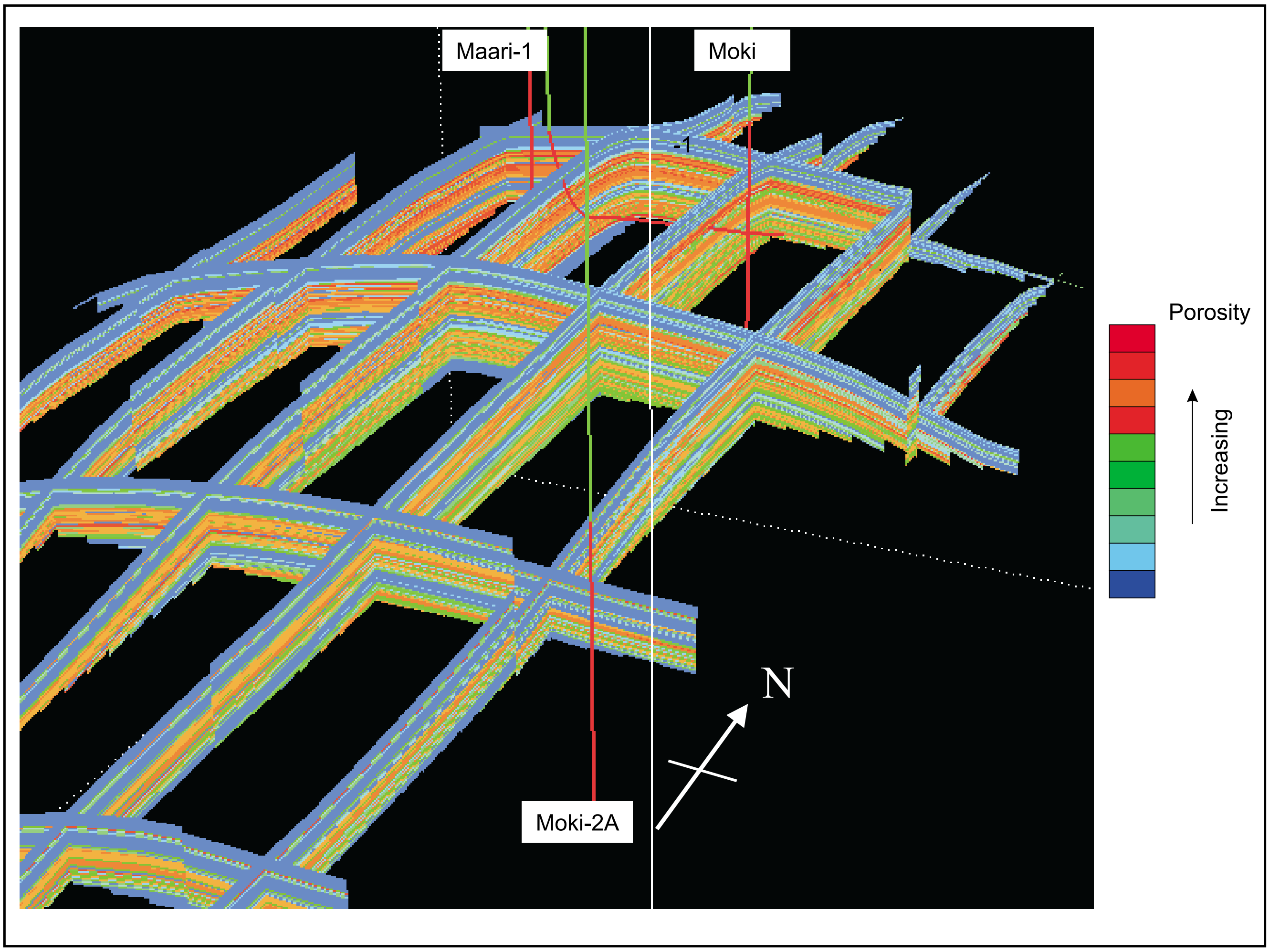

Figure 7: Static reservoir model of porosity distribution in Moki Formation.

Reservoir	STOIIP (million bbls)	Ultimate Recovery (million bbls)	Comment
Moki	100-250	20-60	Water injection
M2A	30-60	0-8	Depletion
Kapuni	20-40	0-7	Oil rim recovery

Table 1: Recovery volumes in Maari.

- Pipelines would be installed by controlled depth or off bottom towing. If oil is also exported to Maui, the pipeline would be unburied, uninsulated and require daily pigging. This gives a very low cost export pipeline and offers significant synergy opportunities with Maui.
- Production using the FPSO Whakaaropai (owned by the Maui JV), may provide significant OPEX synergies to both operators.
- Development wells for Kapuni and M2A reservoirs are liable to be "smart wells", which target multiple zones and control production using surface controlled, downhole chokes.

Uncertainties

The Maari-1/1A appraisal well has increased understanding of the Maari prospect significantly. However, some key uncertainties remain. Follow-up field development study work during 2000, including integration of 3D seismic data into the geological model, is expected to reduce these uncertainties significantly and allow selection of a preferred development concept.

Further volumetric upside is present in one other discovery, Maui-4, and an untested anticline, Pike. The appraisal strategy for these reservoirs will also be addressed during 2000 to tie in with Maari Field development strategy.

Conclusions

The Maari-1/1A well met the prime objectives of proving commercial Moki oil production rates and confirming the Moki reservoir geological model. The new Moki oil play within the offshore Taranaki Basin was thus confirmed, and

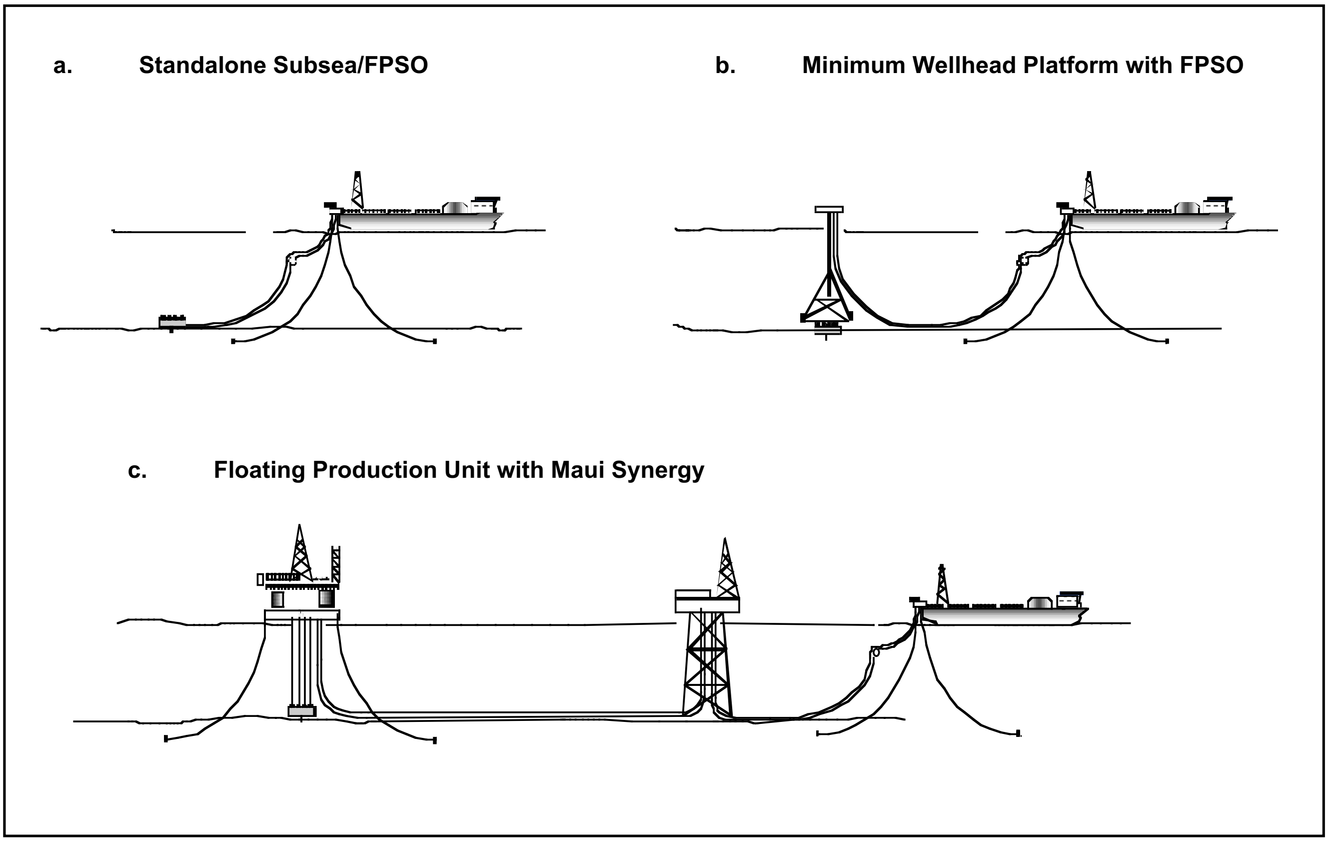

Figure 8: Options for Maari development.

the likely development of the Maari field should prove of significant value to both New Zealand and the joint venture partners.

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Acknowledgements

The authors would like to thank:

JV Partners, Shell (Petroleum Mining) Co. Ltd, Todd Petroleum Mining Co. Ltd and OMV Australia for permission to present this paper.

Contributors to previous Maari work within STOS: Boeren, W., Farmer, R., Hartung, M., Hawton, D., Johnston, J., Reinders-Folmer, A., and The, R.

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