McKee and Mangahewa - under new management

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ABSTRACT

When Todd Taranaki Ltd acquired the McKee and Mangahewa fields in early 2002 it decided to abort the previous ‘produce out’ philosophy and adopt a ‘work the asset’ philosophy in order to extract additional value out of these assets.

The change in philosophy, which applied to the technical-operational area as well as the commercial area, has delivered results already, and some of the successes are described in this paper.

Introduction

Todd Taranaki Ltd purchased the McKee oil field (PML 38086) and the Mangahewa gas-condensate field (PMP 38150) in early 2002 from Shell International, who had agreed to divest these assets to achieve NZ Commerce Commission clearance for the purchase of Fletcher Challenge Energy Ltd.

While these fields were purchased as fully developed, to be managed essentially in produce out mode, Todd Taranaki, and its newly appointed operator – Shell Todd Oil Services - were determined to work these assets in order to optimise the ultimate recoveries and enhance the value of McKee and Mangahewa.

The McKee Field – static description

The McKee structure (figures 1 & 2), located onshore Taranaki, ca. 20 km SE of New Plymouth, was first identified by a seismic survey shot in 1973. The first exploration well, McKee 1, was drilled in early 1980, and proved moveable oil in the McKee Sandstone. A second well McKee-2A, drilled 6 months later, up dip of the discovery well, proved commerciality. A Production Mining Licence - PML 38086 (McKee) was awarded to Petrocorp Exploration Ltd in May 1983.

Further exploration in the vicinity of McKee accumulation continued, and resulted in the discoveries of Pouri, Pukemai/ Tuhua, and ToeToe. In early 1986 these accumulations were rationalised into a single asset/PML – the McKee field.

The geologically complex McKee structure is a major thrust fault feature (figure 3), with a north-east direction. The hydrocarbon accumulation occupies a steep south-easterly dipping (up to 60^{o}) sandstone reservoir sequence truncated against the fault. The field is cut by a number of lesser reverse and normal faults, which may consist of multiple faults or fault zones.

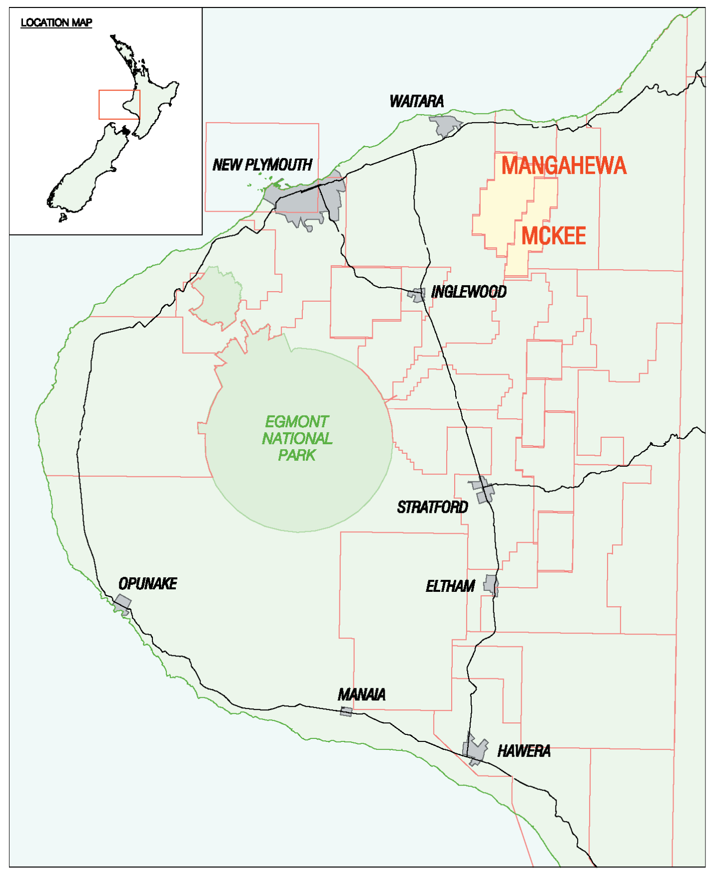

Figure 1: McKee-Mangahewa – Locational map

The structure, which is covered by 3D seismic (1993), is divided into six blocks. From North to South (figure 4) they are:

- Tuhua Block
- Pukemai Block
- Pouri Block
- McKee North Block
- McKee Central Block
- ToeToe Block

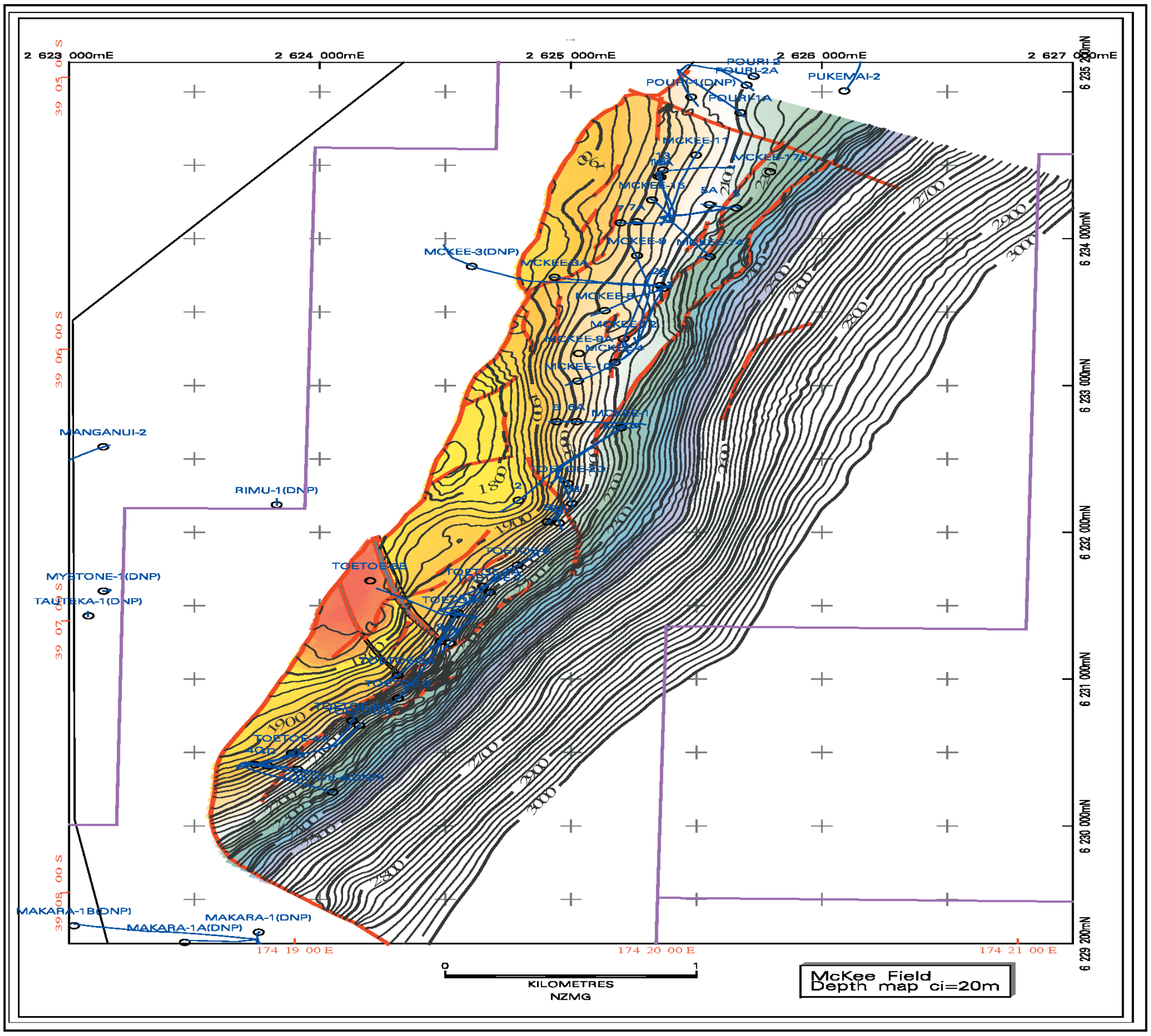

Figure 2: McKee structure map

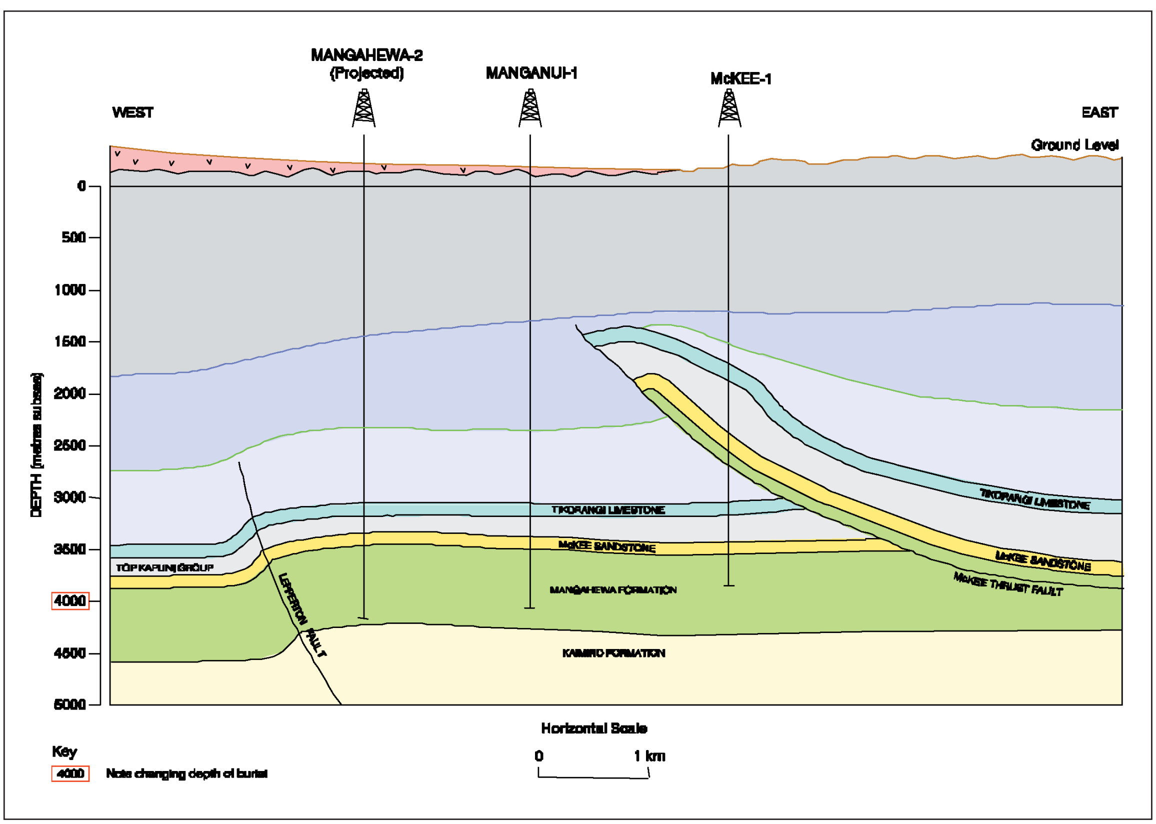

Figure 3: McKee-Mangahewa – schematic cross-section

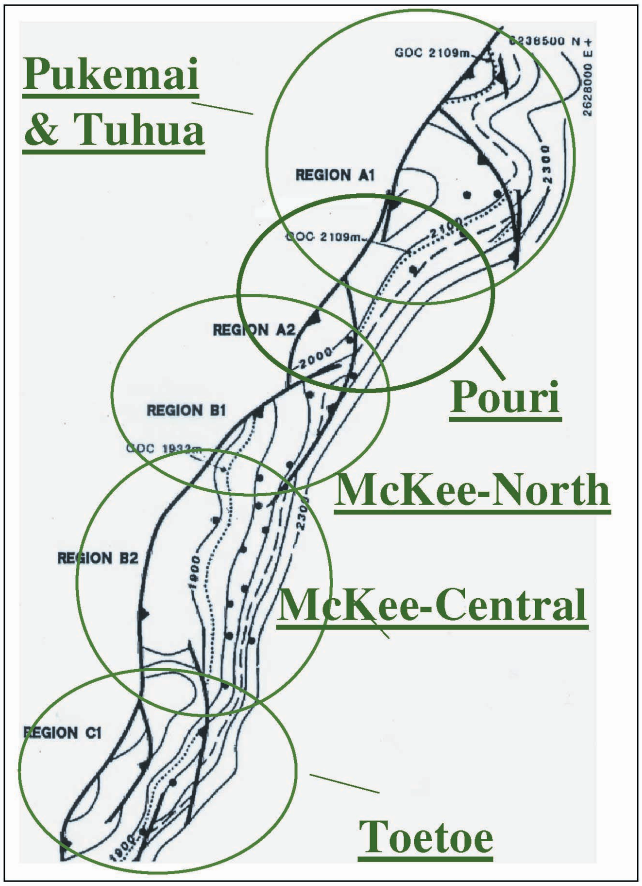

Figure 4: McKee reservoir compartments

The Pouri block is structurally the lowest, and acts as a significant barrier between the North (Tuhua/Pukemai) and the South (McKee and ToeToe).

The hydrocarbon bearing McKee Formation has been interpreted as a transgressional, marginal marine, sandstone sequence where the sediments have been reworked by coastal processes and deposited as a linear, partially emergent feature.

The Turi shale lies above the McKee formation and forms the top seal in combination with the Lower Otaraoa limestone. The thin Matapo sandstone, which lies between the Turi shale and the Lower Otaraoa limestone, is hydrocarbon bearing in areas of the field where it is juxtaposed against the McKee formation.

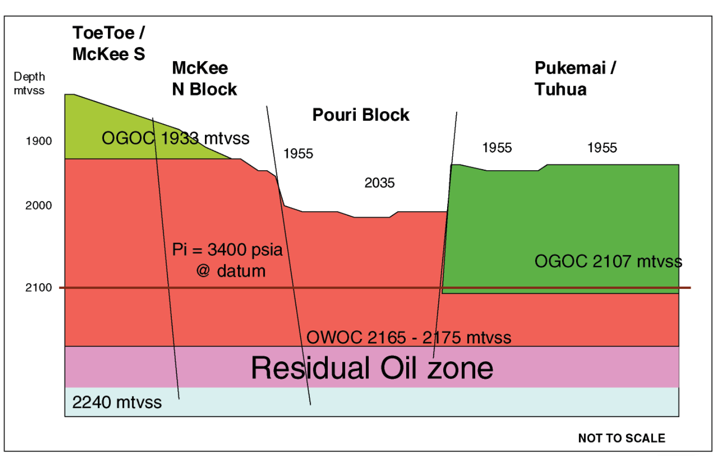

Figure 5: McKee – Original fluid contacts

The Mangahewa Shallow formation (overthrust Mangahewa) lies approximately 80-100m below the McKee, and consists of sand-shale sequences of coastal plain and marine origin, which through juxtaposition are in contact with the (hydrocarbon bearing) McKee formation.

The main McKee formation has been subdivided in four main reservoir units based on lithology, depositional environment and textural properties: A1, A2, IMS (Intra McKee Shale), and A3. The IMS is only present in the northern part of the field.

Apart from the IMS, which is non-reservoir, average reservoir properties are similar for the McKee formation sands, with core porosities around 16-20%, and permeabilities between 100 and 300mD, although considerable heterogeneities within each layer exist. Well test derived permeabilities are considerably lower.

The McKee Structure is compartmentalised vertically and laterally into a number of hydrocarbon pools (figure 5). This is evident from different initial GOCs (Gas Oil Contacts), slightly different PVT (Pressure Volume Temperature) properties, and pressure trends (after production). Intra-block faulting is also resulting in compartmentalisation.

The McKee Field – field development history

Production from the field commenced in late 1983 after commissioning of the McKee Production Station. Initially oil production exceeded 8,000 stb/d, and with infill drilling these high rates were maintained into the early nineties (figure 6), when the GOR and watercut started rising.

Water injection facilities were installed in 1992 to enhance oil recovery by water flooding sections of the reservoir. While this locally increased the sweep efficiency, it failed to arrest the general decline in oil rate and reservoir pressure (figure 7), and the increase in GOR and watercut, which necessitated several facility debottlenecking upgrades.

GOR (Gas Oil Ratio) control has only been implemented to ensure oil production was maximised within the gas compression constraints. The latter was increased twice, from 7.5 MMscf/d to 15 MMscf/d in the late eighties and to 21 MMscf/d in 1994. The last upgrade was not matched with an increase in chilling capacity, as part of the increase was for gas lift to support high watercut production, and the gas buyer could handle ‘off-spec’ gas.

Due to the complexity of the field, dynamic modelling has formed an essential part of reservoir management since inception. This has helped to identify development opportunities like infill drilling (a total of 40 wells have been drilled), and thereby increase the expected oil ultimate recovery (figure 8).

In early 2002, when Todd acquired McKee, it was clear that with an unchanged off-take policy the rapid decline in reservoir pressure and oil production would continue.

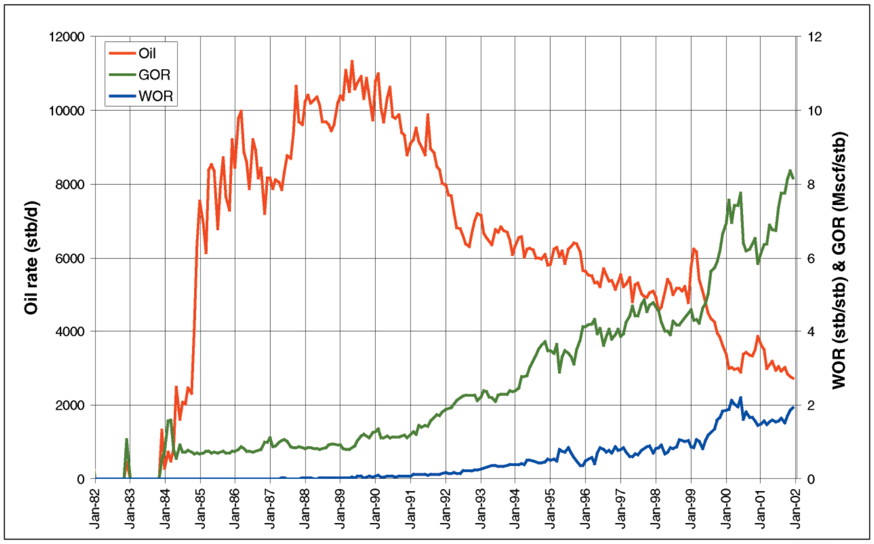

Figure 6: McKee production history (to 2001)

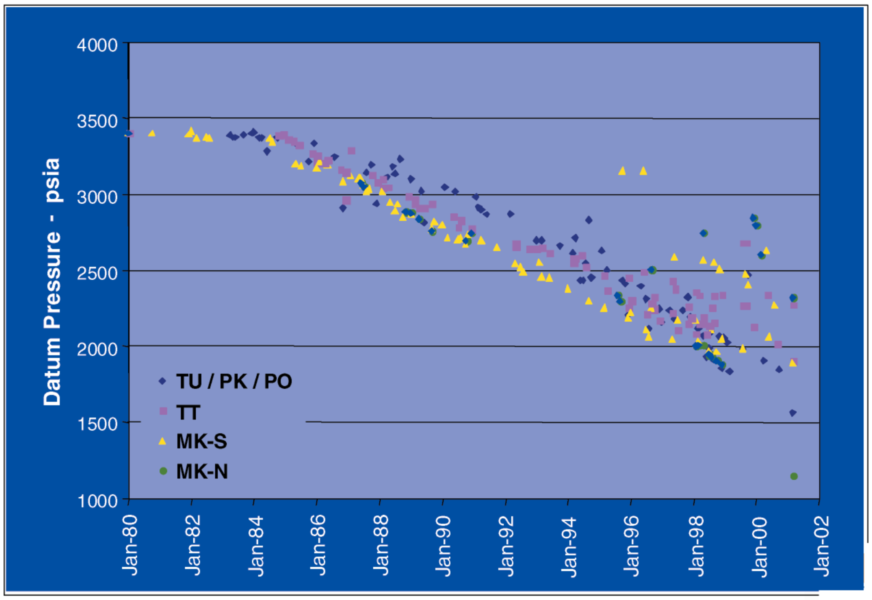

Figure 7: McKee production history (to 2001)

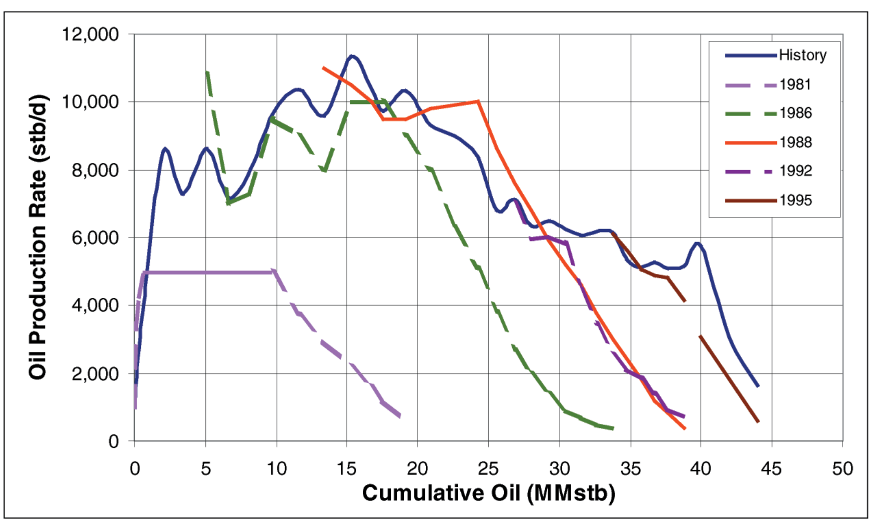

Figure 8: McKee simulation forecasts

The McKee Field – the future

As soon as Todd took over ownership of the field, it implemented reservoir energy conservation measures by closing in high GOR and high watercut producers. It also commissioned Shell Todd Oil Services, its newly appointed operator, to perform reservoir studies to assess how oil and gas ultimate recoveries could be optimised. The latter was a new focus area, as McKee has traditionally been managed as an oil field.

Although the reservoir energy conservation measures at that stage were a leap of faith, without detailed subsurface studies to demonstrate the benefits, (and they also resulted in a significant short term drop in oil production (figure 9)), the limited decline since has proven the benefits and created the window of opportunity for further oil development.

Initial subsurface studies concentrated on updating the 1996 simulation model. This low resolution model (ca. 15,000 grid block) was used as screening tool to assess the optimum technique to maximise oil recovery in the McKee sector (the largest sector, with most remaining oil) by re-injection: water and/or gas injection.

While initial runs indicated WAG (Water Alternating Gas injection) to be promising, later, more detailed modelling, indicated that gas injection should prove most beneficial. As the steep reservoir dip (up to 60^{o}) appears ideal for gas oil gravity drainage, this scouting outcome was in-line with expectations.

Economics based on the scouting studies also revealed that re-injection of all produced gas was not attractive. Incremental oil revenues were insufficient to make up the deferred gas revenues. This indicated that only surplus produced gas would be available for re-injection.

Construction of a more detailed full field model (Eclipse - ca. 230,000 grid blocks), to better quantify the more qualitative results of the scouting studies, commenced in parallel. History matching (figure 10) and some supporting material balance studies, provided a useful insight into the transmissibility of the major faults, and thus communication between the sectors (ToeToe – McKee, and Tuhua/Pukemai – Pouri – McKee).

Based on the initial results, and the increased understanding gained during the early study phases, prediction runs concentrated on optimisation of a single development concept, which makes use of the low connectivity/ transmissibility between the sectors:

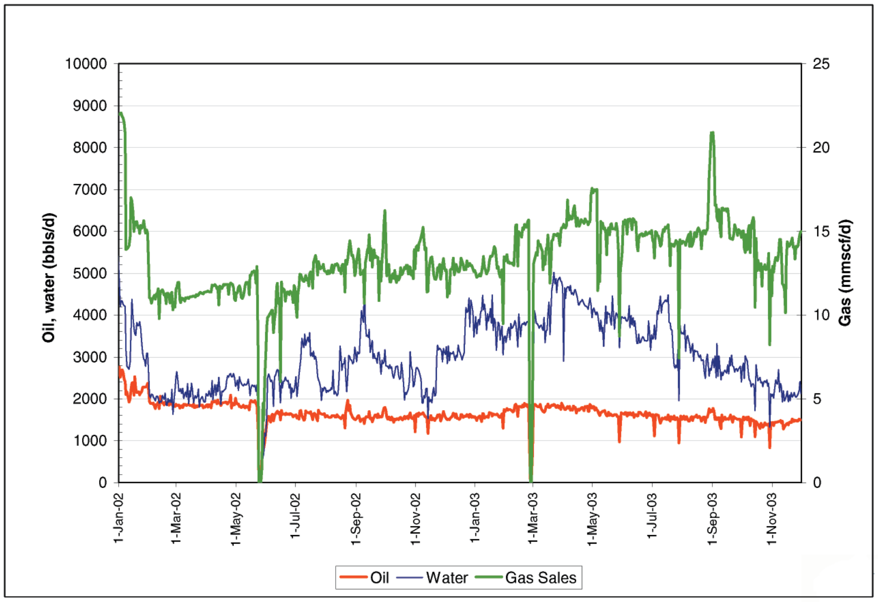

Figure 9: McKee simulation forecasts

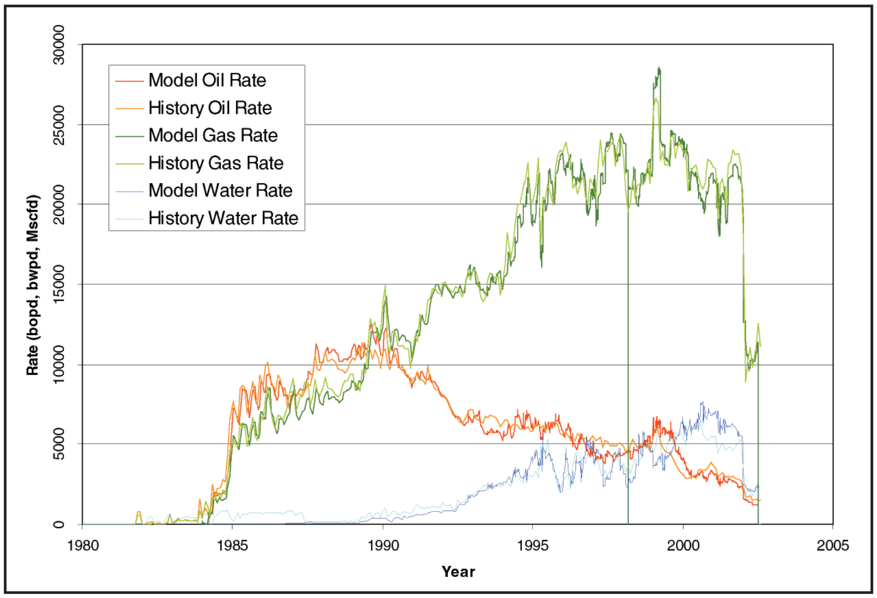

Figure 10: McKee simulation forecasts

- Gas sales increased to 21 MMscf/d after an upgrade of the chilling and dehydration facilities
- Maximisation of gas production from the northern Tuhua/Pukemai section, with surplus gas over sales/own use re-injected in the McKee sector
- Gas from crestal producer ToeToe-6b to complement gas from the northern sectors for re-injection in the McKee block.

The search for additional re-injection gas resulted in identification of gas development opportunities, and optimisation of the gas ultimate recovery.

Encouraged by the optimised prediction runs Todd Taranaki Ltd. has embarked on a NZ$ 11 million Gas Development and Gas Injection project to boost the oil recovery in the McKee sector by some 0.5 MMbbls, and unlock a further 23 Bscf (27 PJ) of gas for sales.

The project will be completed in phases, with the gas treatment upgrades in place in Q2 2004, while the gas injection facilities, which have a capacity of 11 MMscf/d, are expected to be commissioned in Q4 in the same year.

Apart from this Gas Development and Gas Injection project, the studies have also highlighted a number of further development opportunities, currently classified as scope for recovery, which are subject to further, more detailed, studies:

- Wellhead compression to reduce abandonment pressure
- Infill drilling in the McKee and/or ToeToe areas
- Recompletions on the Matapo and/or Mangahewa Shallow sands

As a consequence of the Gas Development and Gas Injection project field abandonment has been pushed back from the back end of the current decade, to middle or end of the next.

The Mangahewa Field – static description

The Mangahewa Structure (figure 11) was recognised as a prospect in the early days of exploration in New Zealand, with the exploration well Mangahewa-1 drilled in 1961 by the Shell-BP-Todd Joint Venture. The well found traces of gas, and on test produced water with a small amount of gas (1-2 MMscf/d). The well was subsequently plugged and abandoned.

A further phase of exploration by state owned Petrocorp occurred in the late seventies/early eighties, with McKee-1 (1979) discovering the overthrust McKee field, and traces of gas in the in-situ Kapuni Group. This was followed by Manganui-1 (1982) and Manganui-2 (1984) to test the southern end of the Mangahewa structure. DST results of both wells were inconclusive, recovering mainly water with traces of gas.

The third and latest exploration phase occurred in the mid nineties, with FCET drilling the Mangahewa-2 gas discovery well (1996/97), short and long term testing of this well (1997), acquisition of 3D seismic (1997), and testing of the northern flank of the Mangahewa structure with Ohanga-2 (1998).

The field is a relatively low relief anticline situated to the west of the McKee overthrust, with few mapped faults. The field is constrained to the east under the McKee thrust, to the north-east by the Ohanga-2 well which encountered good MA72 sands below the hydrocarbon water contact (HCWC) and to the south by the Manganui-1 well. The structure is relatively open to the north-west, where it is constrained only by the seismic mapping, which is very sensitive to velocity uncertainty, resulting in a relatively large GRV uncertainty.

The Mangahewa structure at the Kapuni level is a stratigraphically complex interdigitation of fluvial/estuarine

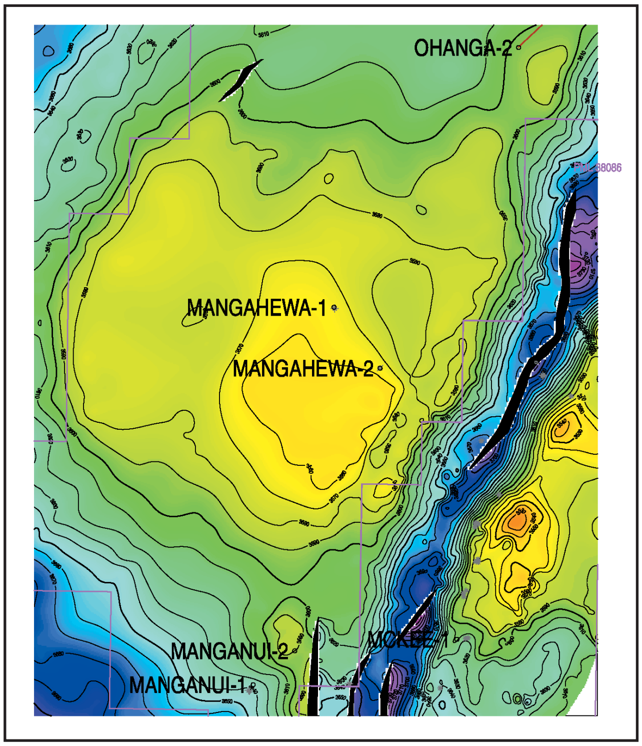

Figure 11: Mangahewa structure (time)

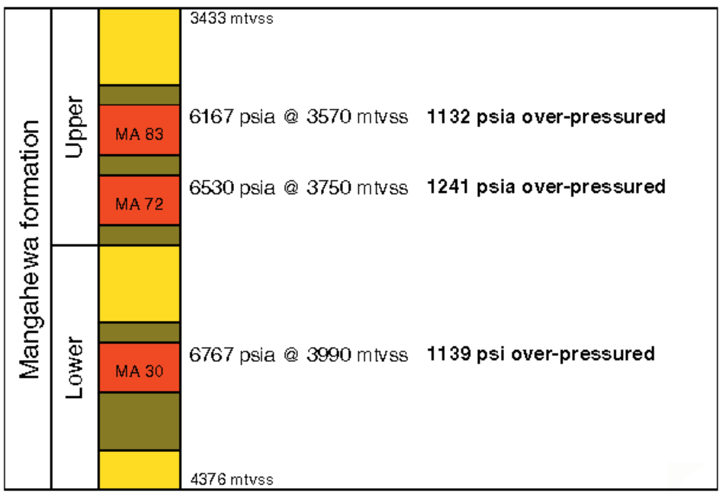

Figure 12: Mangahewa-2 production intervals

and marine sequences (MA99 – MA0). Within the Upper Kapuni Group (> 900m thick) the McKee (MA99 – MA89) and the Mangahewa formations (MA88 – MA0) are recognised, and the reservoir sandstones vary from well cemented very fine to medium/coarse. The sheet-like sedimentological model is based on logs and cores, with coals providing relatively straightforward correlation between the wells.

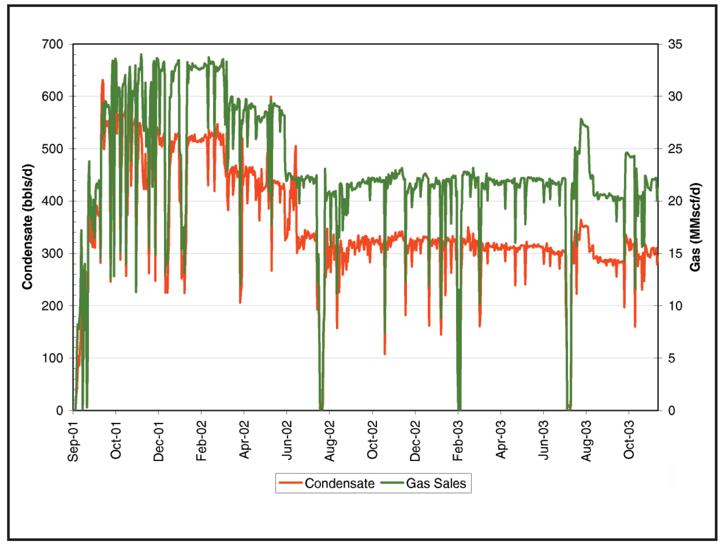

Figure 13: Mangahewa production history

The various reservoir layers, while possibly lateral extensive, are believed to be vertically isolated, as fluid content, gas composition, and pressure regime vary from layer to layer (figure 12).

Reservoir quality varies from sand to sand, depending on the grainsize, the clay content, and diagenetic effects. Porosities up to 12% have been evaluated within the Upper Kapuni Group, and the main producing interval in Mangahewa-2, the MA-72, has an average porosity of 9%, and an average permeability of 4.5mD.

Except for the south-eastern section of the Mangahewa structure, in the vicinity of the Inglewood fault, any horizontal reservoir compartmentalisation is expected to be of a stratigraphic nature, with reservoir pinchout a strong possibility, as minimal faulting is observed on the existing seismic. However, minor faulting is beyond the resolution of the seismic, and can not be excluded.

The Mangahewa Field – field development history

After drilling Mangahewa-2 six zones of interest were identified from the logs as potential candidates for testing with hydraulic fractures. For cost and logistical reasons testing had to be constrained to 3 zones, the MA-30, the MA-72 and the MA-83.

The post-frac (short term) test results, through the 3½" completion were:

Zone (mtvss)	Depth (psia)	Pr @ 3990 mtvss (psia)	Over-pressure (psig)	FTHP (MMscf/d)	Gas rate (stb/MMscf)	CGR (stb/MMscf)	WGR (mol%)	CO2
MA-83	3458	6167	540	3300	3	15-22	< 30	12
MA-72	3564	6530	902	4450	18	12-14	2	3.5
MA-30	3975	6767	1139	ca. 600	2	16	< 70	3

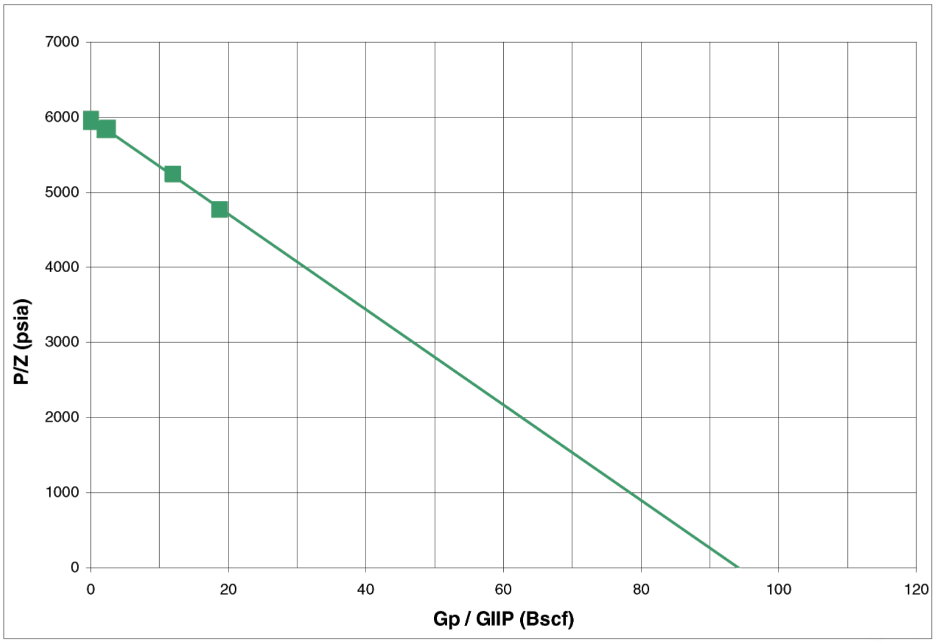

Figure 14: Mangahewa P/Z performance

Based on these encouraging test results, a commingled MA-72/-83 long term production test was conducted between December 1997 and July 1998 during which period some 2.7 Bscf and 36,000 bbls of condensate were produced.

The permanent Mangahewa-2 production facilities, which are single train, and integrated with the McKee facilities for the provision of utilities and for treating condensate, water and LTS liquids, were commissioned in September 2001. The production performance since start-up (figure 13) has been influenced by gas contract management, and the back production of frac sand, which necessitated off-take restrictions. These reservoir off-take restrictions have been lifted after a cyclone type wellhead desander was installed in mid 2003.

Cumulative production by end 2003 was 22 Bscf of gas and 0.33 MMbbls of condensate. Water production has been constant at 2 bbls/MMscf, which is all condensed water (no free water production).

Assessment of reservoir performance is based on the P/Z methodology to estimate the GIIP connected to Mangahewa-2, and a material balance model to assess the UR, and remaining reserves.

With over 2 years historical production the uncertainty range on the connected GIIP has been narrowed considerably, with the expectation GIIP currently estimated at 94 Bscf (figure 14). This GIIP is used in a simple dynamic model (Mbal + Prosper) to predict the ultimate recovery, remaining reserves, and a production forecast for Mangahewa-2 as currently developed.

Condensate reserves estimates and forecasts honour the PVT properties and the expected condensate drop-out in the reservoir as the reservoir pressure declines.

The Mangahewa Field – the future

Similar to the approach with the McKee field Todd, together with STOS, has adopted an approach of working the asset as soon as it gained control. The prime focus has been on geoscience work, with a geophysical re-interpretation of the seismic data set, which includes data from nearby permits.

Despite these study efforts, the low relief and the depth of the reservoir combine into a relatively large GRV uncertainty, as the depth conversion is very sensitive to velocity. In the low case (P90) the volume of reservoir layer MA-72 matches closely with the connected GIIP seen by Mangahewa-2, in the high case (P10) there is considerable scope for further drilling. Geoscience studies, including quantitative seismic, are ongoing to identify an optimum location for an appraisal well.

Construction of a full field simulation model is also in progress. It is expected this model will not only confirm the viability of an economically robust wellhead compression project, but also assist in assessing and optimally developing tight gas opportunities. As with Mangahewa-2 any new appraisal well in the Mangahewa structure is expected to find numerous gas filled intervals, with the key uncertainty being productivity. Understanding the productivity potential of those low reservoir quality intervals, and the productivity improvement which can be achieved by hydraulic fracturing, is key to unlocking that potential. A production test, possibly followed by a hydraulic frac, in observation well Ohanga-2, a well deviated from the former PPL 38705 into the Mangahewa permit, is planned to confirm and validate the concept and model.

McKee and Mangahewa – operational issues

Operationally the fields were initially managed on a 'business as usual' basis. Continuity was achieved by the transfer of operational staff from the FCET/Shell organisation to STOS, while maintenance staff were transferred to various maintenance contractors employed by STOS.

Alignment of the operational processes, procedures and standards with the STOS processes, procedures and standards has been done gradually, with an initial focus on HS&E and integrity issues. HS&E performance indicators provide evidence that the integration of McKee-Mangahewa was successfully managed, with a TRCF (Total Recordable Case Frequency) inline with (2002), or better than (2003) the other STOS operated sites.

A long list of items identified during the due diligence process, which included safety and integrity audits by external resources, is being addressed. Priority setting is risked based, and in most cases the close out starts with a detailed review of the original findings to validate the action point. In numerous cases this revealed that no further action was required, as several of the original findings were based on limited data (short time span for due diligence, or due to data access/retrieval problems), or quantitative risk assessments indicated the risks to be minimal.

Areas which did require action, and have been actioned, include the replacement of the automatic wellbore wax-cutting systems (with new wireline-BOP inclusive systems), installation of a fusible loop fire detection system around the existing gas engine compressors, installation of double block and bleed facilities for the gas fired heaters and engines, and segregation of the EDP from the ESD system.

Initial progress on some of these items was hampered by a leak in the McKee oil export line, which manifested itself within weeks of the purchase. The integrity of this pipeline was identified as an ‘unknown’ during the due diligence process, and an intelligent pig survey was pencilled in for late 2002 or early 2003.

Although trucking of the crude as alternative export method was organised quickly, and limited deferment was experienced, pipeline reinstatement proved time consuming and costly due to hard wax deposits coating the inside of the pipeline. A number of cleaning pigs got stuck in the line, and had to be retrieved by excavating and cutting the line. At the end only the highest risk upstream part of the pipeline was inspected with an intelligent pig, while the integrity of the repaired line was proven by a hydrotest.

The pipeline leak was a result of external corrosion after failure of the FBE (Fusion Bonded Epoxy) coating, due to overprotection by the cathodic protection system causing blistering and disbondment, and/or rock damage. Subsequent periods of underprotection (especially during wet periods) enabled external corrosion.

CIP (Closed Interval Potential) Surveys will now be complemented with DCVG (Direct Current Voltage Gradient) surveys to ensure that coating defects are identified early.

Another area of focus was the extension of the McKee license. With the original PML 38086 expiring in late 2003, a license extension had to be secured prior to any significant development expenditure (Gas Development – Gas Injection project). The MED approved a 22 year extension (to November 2025) in May 2003.

McKee and Mangahewa – commercial issues

The purchase of the McKee and Mangahewa assets included the remaining commitments under the ‘20PJ Gas Sale & Purchase Term Sheet’ and the ‘Mangahewa Gas Sale & Purchase Agreement’ between Energy Exploration NZ Limited (“FCE”) and Methanex New Zealand Limited.

Due to nearing end dates for both agreements, the constraints provided by the McKee-Mangahewa gas export system, and the changes in the gas market at the time, Todd Taranaki Ltd. negotiated a new gas supply contract with Methanex.

Todd also commenced the process of gaining access to the Maui pipeline. Due to the complexity, and the many parties involved, Todd elected to separate this process in two:

1. Physical connection to the Maui pipeline

   This process was driven by Todd operations team in New Plymouth, and aimed to connect the McKee-Mangahewa gas export pipelines with the Maui pipeline at the Tikorangi Main Valve Station. This tie-in had to meet the appropriate safety and integrity standards, as well as measurement and data management standards of a wide range of possible open access regimes.
2. Commercial agreements to govern an Open Access regime for the Maui pipeline

This process is being driven by the Todd commercial team in Wellington, and involves all Maui White Paper parties – Sellers, Buyers and the Crown. The new regime requires agreements on gas specifications (Maui spec [1] NZS-5442), gas balancing, gas reconciliation, gas mismatch, and UFG (Unaccounted For Gas), amongst others, either to replace or complement sections of the original Maui White Paper contract.

The physical connection was approved by MDL (Maui Development Limited) in late 2003, and construction is expected to be completed in early 2004. The meters are state of the art, and with the installed distributed control system it will be possible to deliver the data and set the controls as required by any open access regime.

At the time of writing the Open Access regime was still under development.

In the third quarter of 2003 Todd embarked on a gas auction process for the sale of more than 100 PJ of uncommitted McKee and Mangahewa gas. Interested parties, who signed a confidentiality agreement, were issued with an Information Memorandum, Sales Rules, a Bid Form, and a draft Gas Supply Agreement.

Prospective buyers could bid for tranches of gas as a percentage of the EAP (Expected Annual Production), and non-conforming bids were accepted. At the time of writing the 3rd and final round was being finalised.

Although novel to the New Zealand gas industry, the auction process is expected become the norm, and will help to establish a more transparent gas market with a fair market price.

Summary

The 'work the asset' management philosophy adopted by Todd Taranaki Ltd. when it took ownership of the McKee and Mangahewa assets in early 2002 has been very successful. Initiatives adopted included:

- Implementation of McKee gas off-take restriction to conserve reservoir energy until the field was better understood
- Development of detailed reservoir models to assess optimum off-take policies, and identify development opportunities to increase ultimate recovery:
  - Re-injection – gas, and/or water
  - Block/area communication and off-take management
  - Wellhead compression
  - Infill drilling
  - Increased gas focus
- Improved safety and integrity management
- Gas sales via an auction process

Acknowledgement

Todd Energy would like to thank all Shell Todd Oil Services staff who are involved in the McKee and Mangahewa operations, and especially the subsurface study team, for their support to these assets.

Author

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In 2002 he joined Todd Energy as Onshore Assets Manager. In that role he is responsible for managing the Todd interests in the McKee (100%), Mangahewa (100%) and Kapuni (50%) fields.