A summary of data indicating increased reservoir complexity in the McKee Field

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Abstract

Analysis of pressure and production data from the McKee Field, a recently drilled well, plus re-interpretation of seismic and geological data has resulted in major changes to the originally assigned reservoir and geological parameters.

The field was initially defined as a steeply dipping, reasonably homogeneous sandstone reservoir producing under gas cap expansion with little or no aquifer support. The up-dip limit of the field was defined by a major thrust fault. The down-dip limits were determined using the oil-water contact and/or sealing back-thrust faults running approximately parallel to the main thrust fault. A recently installed waterflood may have improved oil production in the central portion of the field. Sixty percent of the drilled in-fill wells missed their original reservoir target and had to be plugged back and sidetracked.

Based on proven compartmentation, aquifer support and communication between various sections of the reservoir it became obvious that the original reservoir management plans needed to be modified or in some cases completely revised.

Introduction

McKee is the largest Fletcher Challenge Energy-operated field in New Zealand. It is structurally complex, contains reasonably good quality reservoir rock and at present produces 3000 bopd with 25 mmscf/d of associated gas. The oil is shipped via pipeline to the Omata Tank Farm near New Plymouth for export and the gas is compressed for gas-lifting the oil wells or for export to the gas reticulation infrastructure. Refer to Figure 1 for the location of the McKee Field and the surrounding infrastructure.

Discovered in 1980 with the drilling of the McKee-2 well the field now contains forty three wells, oil and gas production facilities and a small waterflood in the central portion of the field. Refer to Figures 2 and 2A for a well location map and a cross-section through a typical well (ToeToe – 6). The field is made up of five distinct areas (Tuhua, Pukemai, Pouri, Central McKee and ToeToe) which appear to have varying degrees of pressure and fluid communication. From an initial average reservoir pressure of 3415 psi the pressure has declined to the current level of approximately 2000 psi. The majority of down-dip producing oilwells require gaslift to continue flowing while wells located near the gas-cap area are cycled to minimise gas coning problems.

Figure 1: McKee Field location and existing infrastructure.

The interpretation of reservoir, geological, production and pressure data from the McKee Field has been continuously modified as additional information becomes available. With the benefit of recently gathered data it is easy to question some of the original interpretations applied to the McKee structure and reservoir characteristics. The following summary highlights the major actions and decisions taken during the life of the McKee

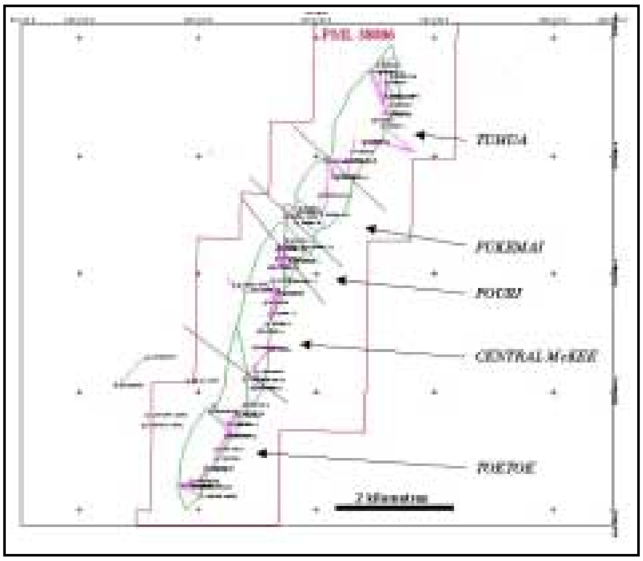

Figure 2: McKee well location map.

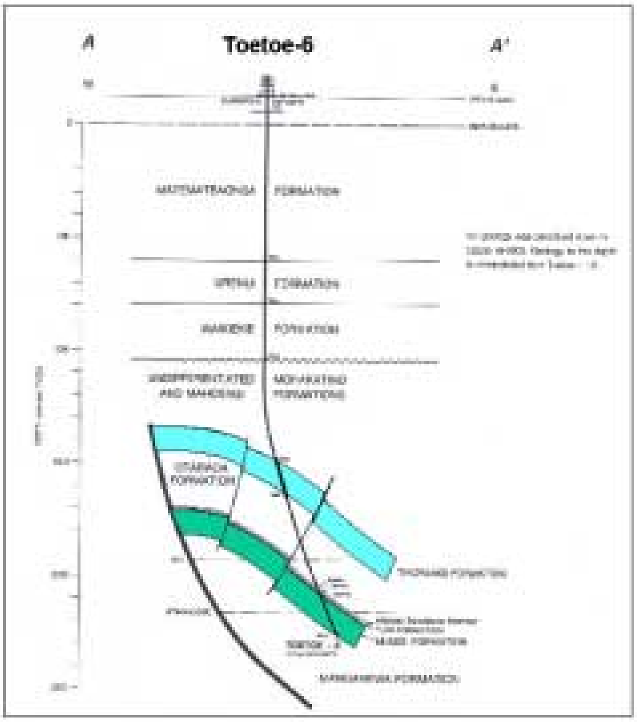

Figure 2A: McKee cross-section in ToeToe-6.

Field. Dates followed by a # symbol (eg. 1995#) are shown for historical interest but do not contribute to reservoir complexity issues. Where applicable the history includes the impact that these actions and decisions have had on McKee's performance.

Historic field development highlights

1979 - First well drilled. The McKee-1 well did not encounter commercial hydrocarbons, but it did confirm their presence. The McKee–2A follow-up well discovered the McKee Field in 1980. Refer to Figure 3 for a plot of cumulative wells drilled by year.

1984 – Based on the results from the first reservoir model it was concluded that there was no aquifer support and that oil recovery would be between 40-50%.

1984 # - First commercial oil production.

1987 - An injectivity test on McKee-1 indicated that the reservoir would not readily accept large volumes of water.

1989 # - Oil production peaked at 12,000 bopd.

1989 - Drilled the first of two horizontal wells. McKee-12 was drilled in November, 1989 close to the oil-water contact and very quickly watered out. The Tuhua-4 well was drilled in January, 1990 and has produced 225,000 barrels of oil with no water production to date.

1991 # - Reduced the operating pressure at the production station from 440 psi to 180 psi to increase production.

1992 # - Began using GOR (gas oil ratio) control to regulate wells that showed gas coning tendencies. This operating practise was removed in 1993. Refer to Figure 4 for a comparison of production versus wells drilled over time.

1993 - Ran a 3D seismic survey over the entire field. The expected results of improved geological/fault interpretations were not realised due to the steep dip along the flank of the reservoir and the short length of the shot lines.

1993 - Performed core studies that changed the reported values of the Sor from 38% to 32%. The same study indicated that a waterflood would further reduce the Sorw to 29% while gas injection would reduce the Sorg to approximately 11%.

1994 - Drilled four Tuhua Hill infill wells. The Tuhua-6, 8A and 9 wells exhibited increasing GORs almost immediately after initial production and are currently either shut-in or cycled. The Tuhua-7 well was isolated by a down dip back thrust fault and has produced in excess of 310,000 barrels of oil. Refer to Figure 5 for a summary of wells drilled versus estimated ultimate oil recovery.

1995 - The McKee-1 and 14 wells were placed on injection and it was felt at the time that they were isolated from the remainder of the field by a north-south trending back thrust fault. Injectivity pressures approached the reservoir fracture gradient. The need for a constant supply of injection water resulted in the construction of a 11,000 bwpd plant to treat fresh water from the nearby Mangaone Stream

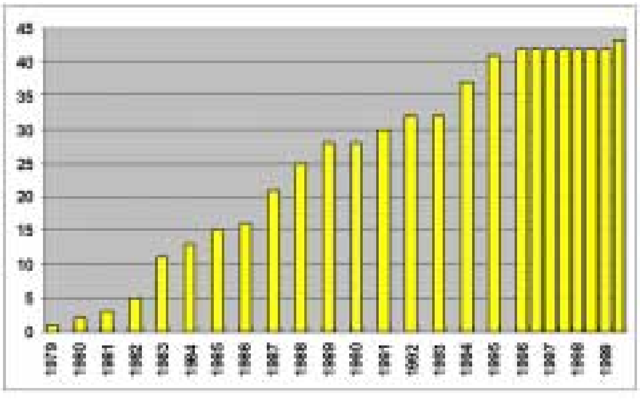

Figure 3: Cumulative wells drilled by year.

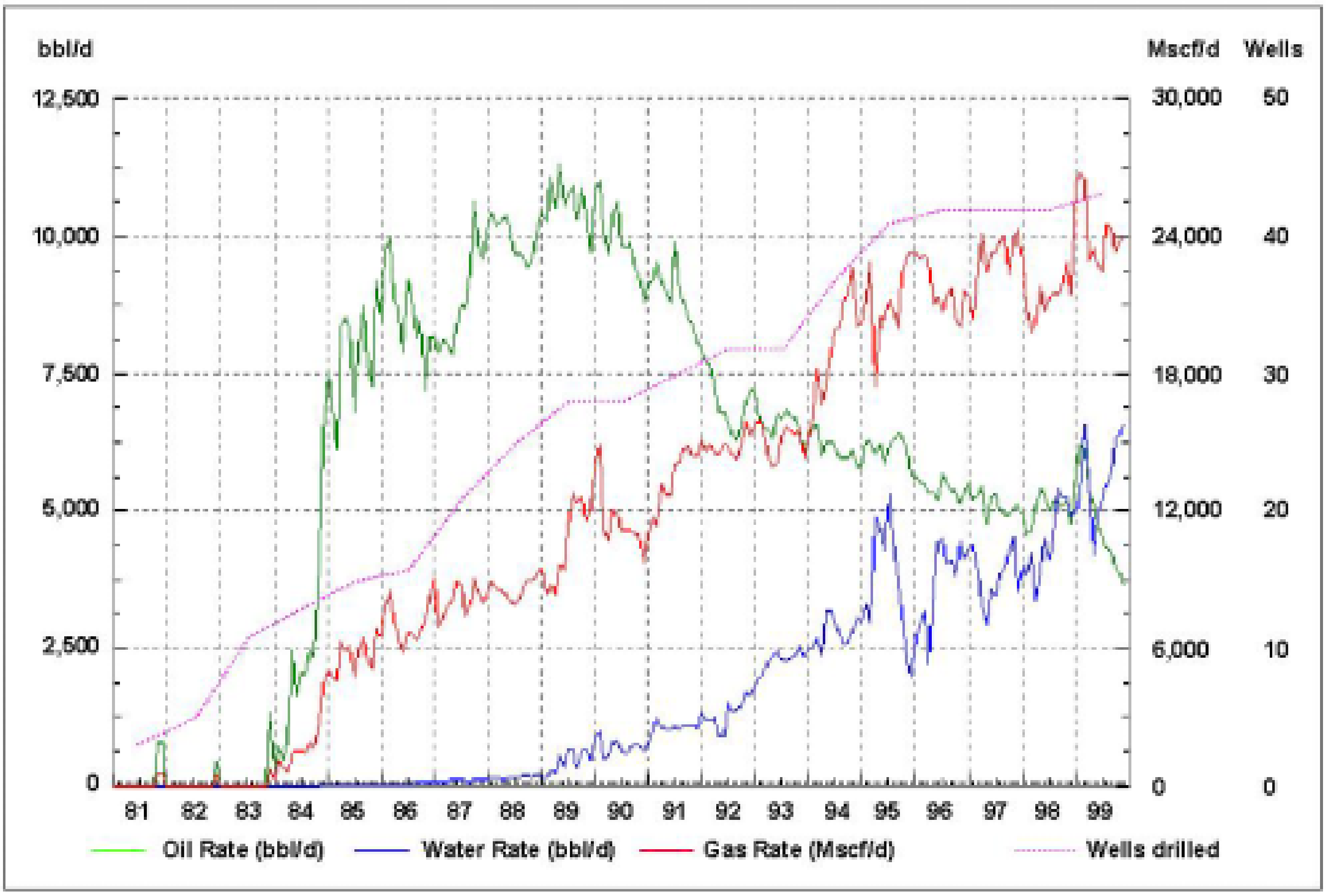

Figure 4: Production versus wells drilled.

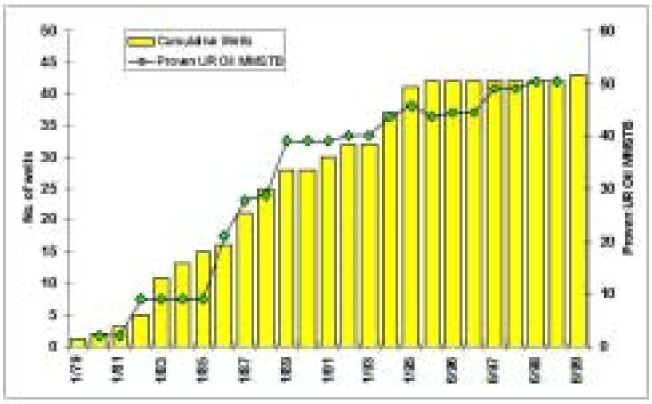

Figure 5: Wells drilled versus oil reserves.

1997 - Drilled the ToeToe-4D well into the same isolated fault block that ToeToe-5A was located in. These two wells define the southern extent of the McKee field.

1997 # - Extended the waterflood to the Central McKee area using the McKee-2A, 4 and 5A wells that had watered out. Refer to Figure 6 for the production history of a typical McKee well (McKee – 2A). Expanded the capacity of the Mangaone fresh water facilities to 21,000 bwpd.

1997 # - Expanded the waterflood to the Pouri area by drilling Pouri-2A and placing it on injection.

1998 # - Completed a catalogue of the water salinities from most wells in the field. This data is useful in the identification of produced water in the wells and helped in the identification of scale recovered from the Tuhua-8 well.

1998 - Returned ToeToe-3A to production following an extended shut down after the well had gassed out. Refer to Figure 7 for details of the well history. There are three possible explanations for the behaviour of this well: 1) a partially sealing back thrust fault located updip from the well allowed a secondary gas cap to develop. This gas cap bled off over time. 2) The gas channelled directly from the gas cap or 3) the aquifer became active as the reservoir pressure declined and the previously expanded gas cap moved back updip. The well is currently producing with increasing water volumes and this appears to favour the active aquifer case. However, the gas oil ratio is also increasing and the lack of updip wells leaves both options concerning the gas cap open to discussion.

1999 – A pressure survey run in well Tuhua-1 indicated cross-flow from the deeper Mangahewa zone to the shallow McKee formation.

1999 - Completed a WOR (Water Oil Ratio) and GOR (Gas Oil Ratio) derivatives study that indicated that many of the wells had watered or gassed out due to channelling rather than by the uniform sweep of water or gas cap expansion.

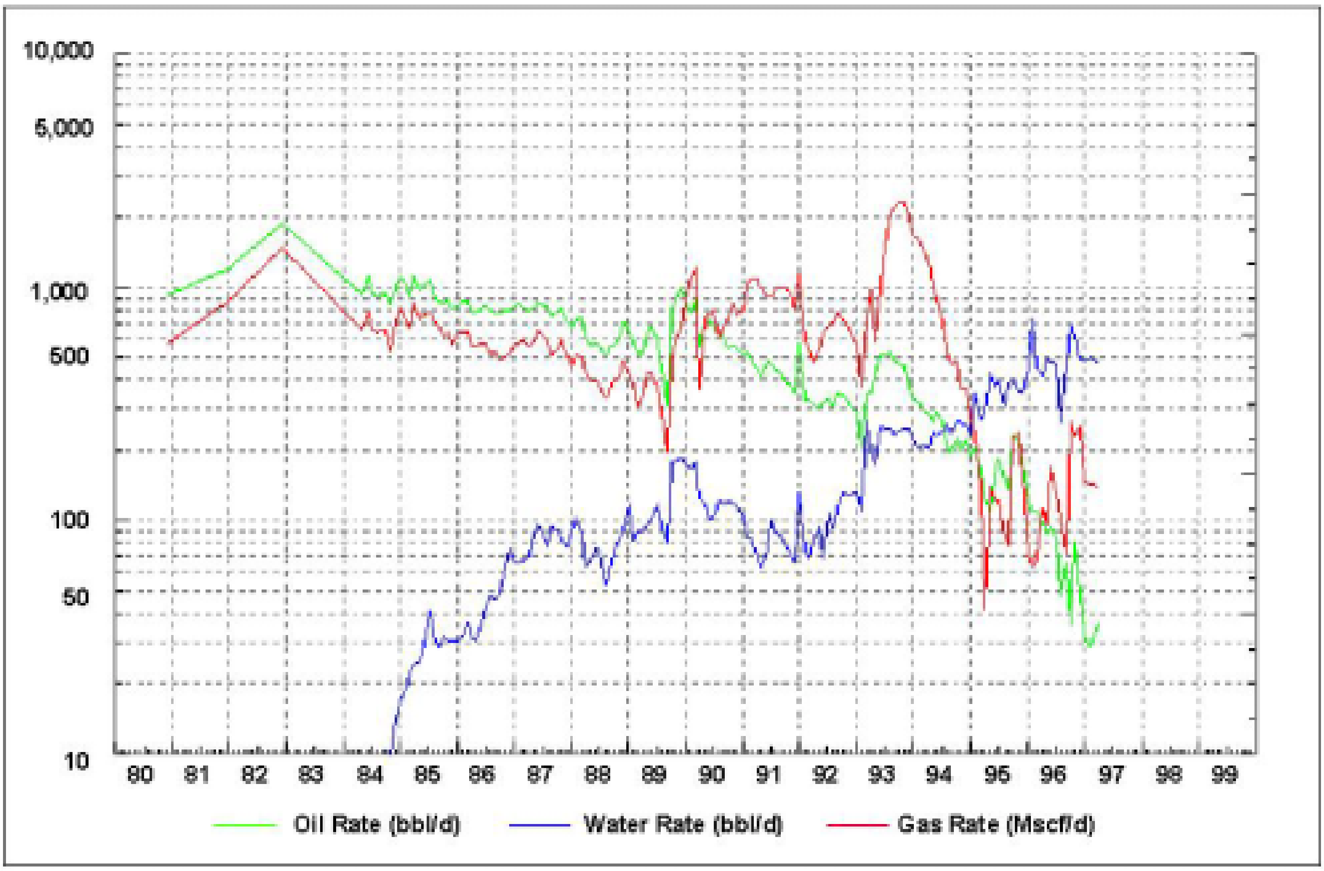

Figure 6: Typical production history of a McKee well.

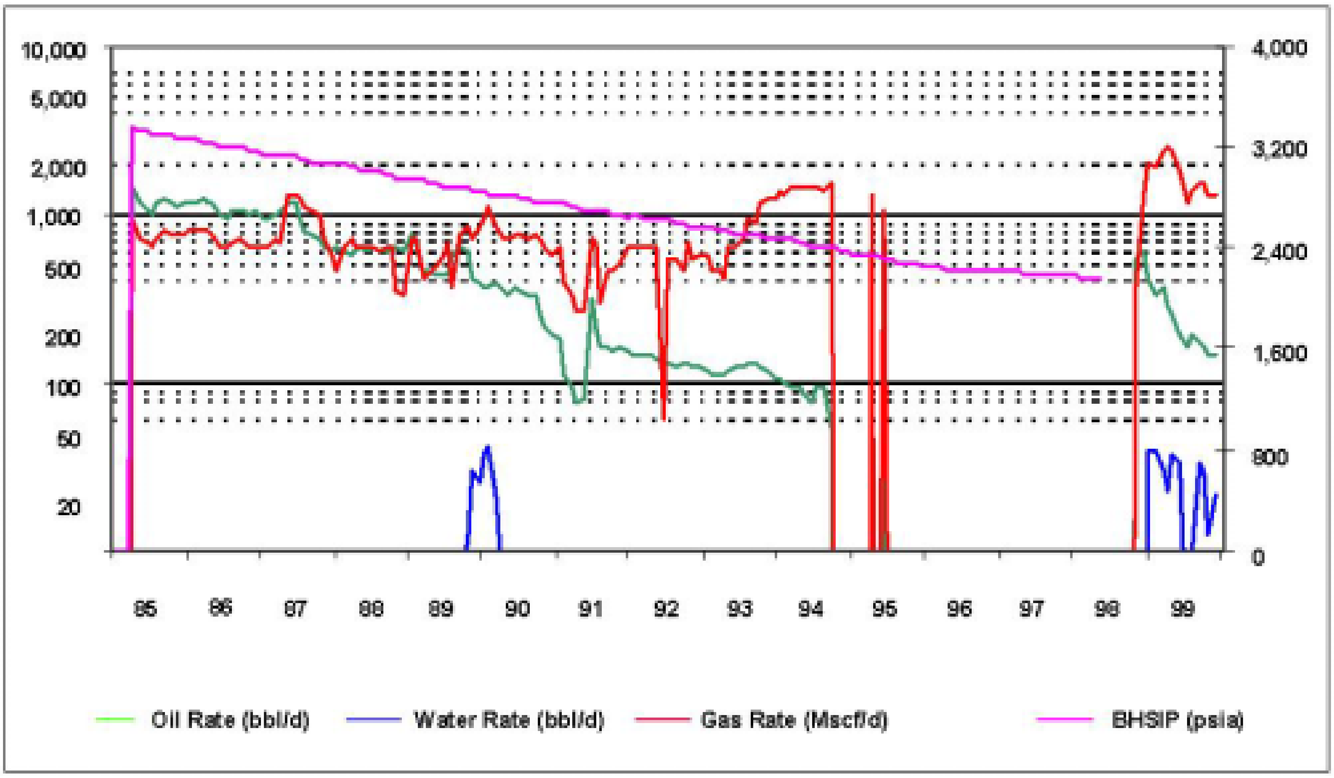

Figure 7: ToeToe-3A production history.

1999 - Sidetracked the ToeToe-6 well to look for: 1) possible production in the shallow Tikorangi formation, 2) locate the top of the McKee reservoir, 3) evaluate the productivity of the Mangahewa formation and 4) intercept the main thrust fault.

1999 - Used coiled tubing to remove scale build up blocking access to the McKee formation in the Tuhua-8 well. The scale composition indicated that it was most likely formed by water from the underlying Mangahewa formation.

Declining bottom hole pressures and interference test results

The initial reservoir pressure measured at the time of discovery was 3415 psia and it has declined to the current level of approximately 2000 psia. There are local pressure variations across the field but it is doubtful that any portion of the field is totally isolated from the other areas. Refer to Figure 8 for a history of the available pressure data in various parts of the field. It is apparent from several interference tests that communication is either along very torturous paths or through partially sealing faults. The pressure data for wells McKee-4, -10 and -12 shown in Figure 9 illustrates that the wells are obviously not in direct communication with the McKee-6A and -8 offset wells. The length of time required for this pressure difference to equalise is not yet known.

The start of continuous waterflood injection resulted in increased pressure differentials across parts of the Central McKee area and several major differences from accepted theory were quickly evident. Refer to Figures 10 for the pressure history of the Pouri area and Figure 11 for results of an interference test between the McKee-14 injector and McKee-9 oil well. Figures 12 and 13 are geological cross-sections between the Pouri and McKee wells respectively. In the Pouri area where the injection well and offset producer are less than 200 m apart there is no apparent communication after two years of injection. Six hours after starting injection into the McKee-14 well, which is 300 m from the McKee-9 producer, McKee-9 showed a rapid pressure increase. The McKee-1 well, which had served as a McKee formation disposal well and eventually as an injector, was found to be in communication with the ToeToe-2D well but the offset McKee-6A well was not in communication with either well. McKee-6A also appears to be isolated from other offset wells in the area. Refer to Figure 14 for details of the wells located in this area.

Pressure and temperature surveys recently identified a major problem involving the McKee-2A, -5A and -14 injection wells and the McKee-9 shut in oil well. As mentioned earlier, the communication between McKee-14 and -9 was clearly established in October of 1999. In January, 2000 following several weeks of being shut in a temperature survey was run in McKee-14. The objective of the test was to determine if expected wax precipitation caused by the injection of cold water was acting as an insulator in the reservoir. The pour point temperature of the McKee crude is 86 degrees F. The temperature measured in McKee-14 was 75 degrees F versus an expected temperature of 175 degrees F. A subsequent interference test in McKee-2A, -5A and -14 confirmed direct communication between all three wells through either natural or induced fractures. Pressure communication between McKee-14 and -9 was not present during the initial injection tests conducted in early 1995 but may have been established during an acid job in October, 1995. Figure 15 shows that McKee-9 watered out much faster than expected and this is attributed to an induced fracture.

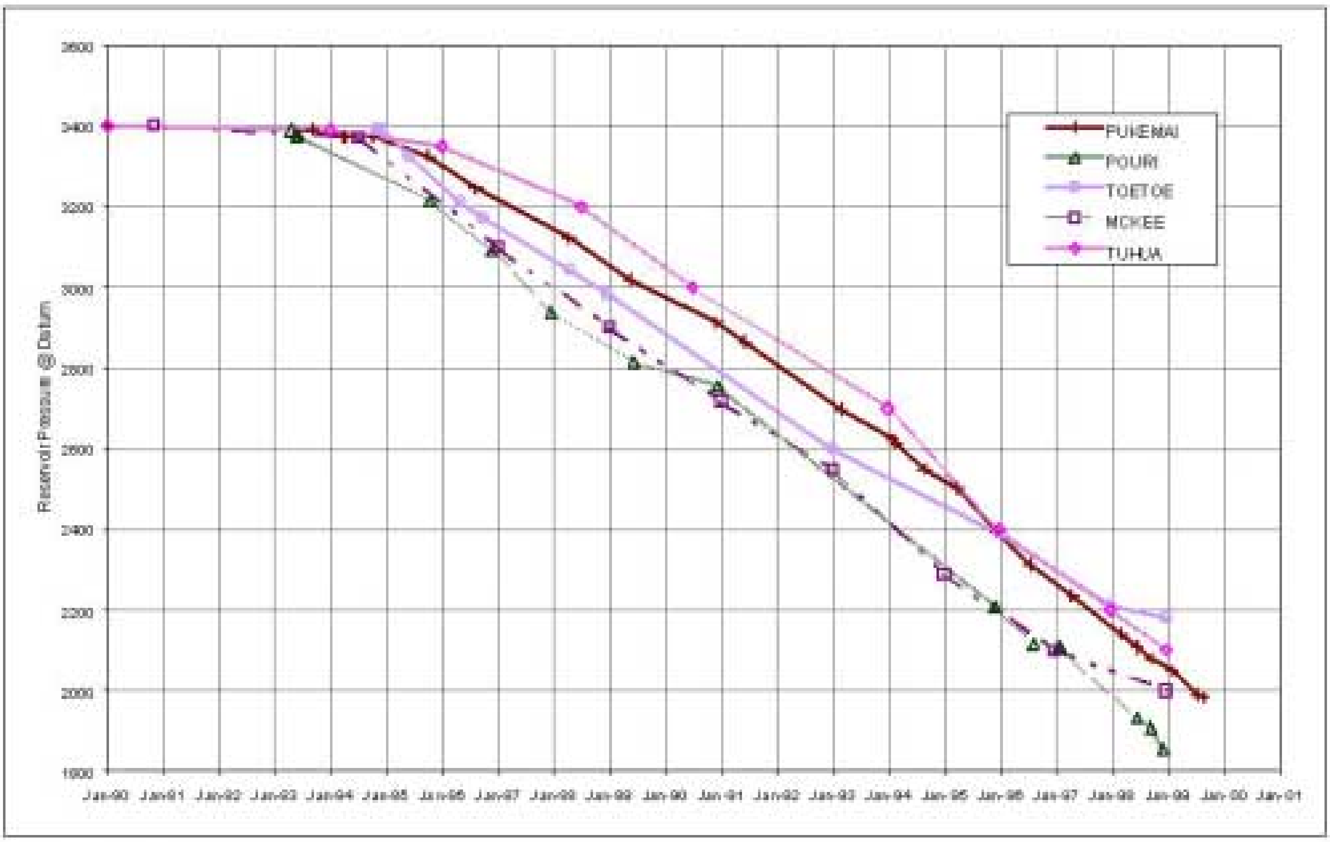

Figure 8: Pressure history.

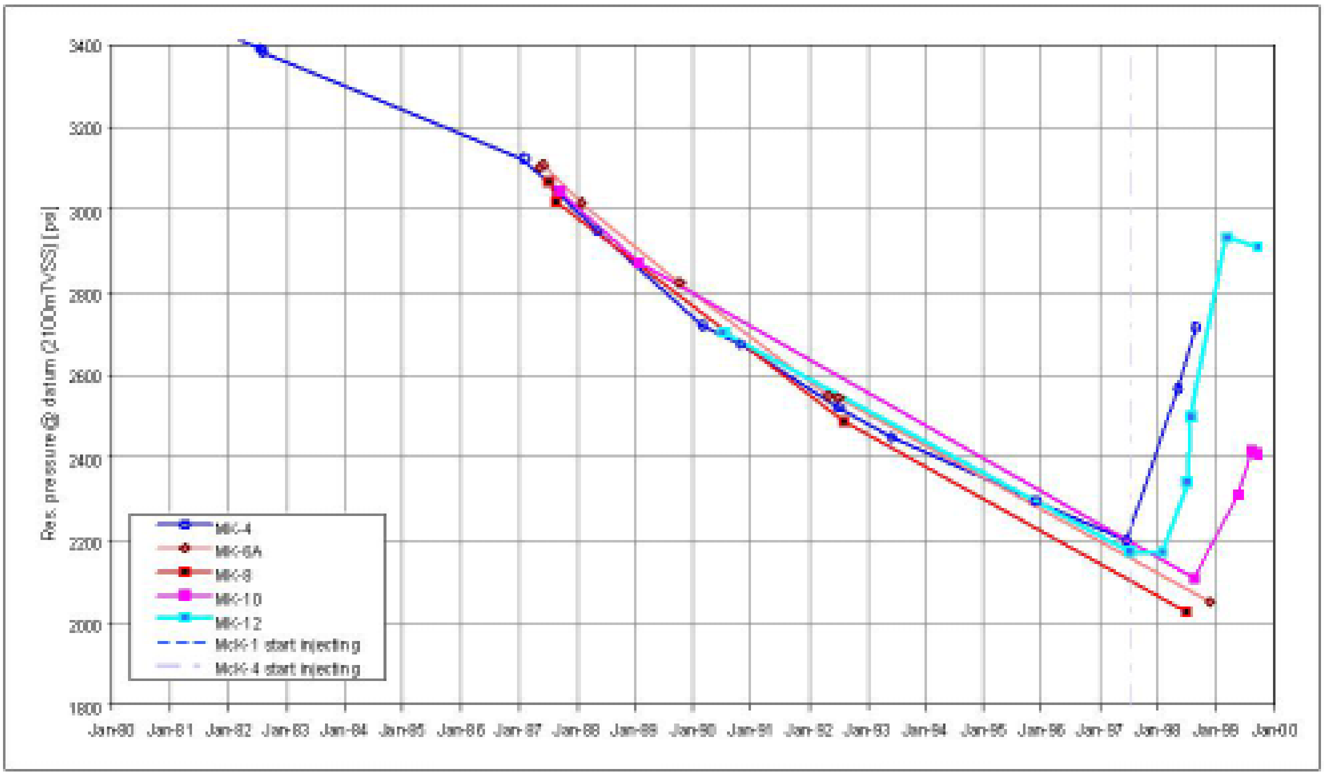

Figure 9: McKee-4, -10 and -12 pressure data.

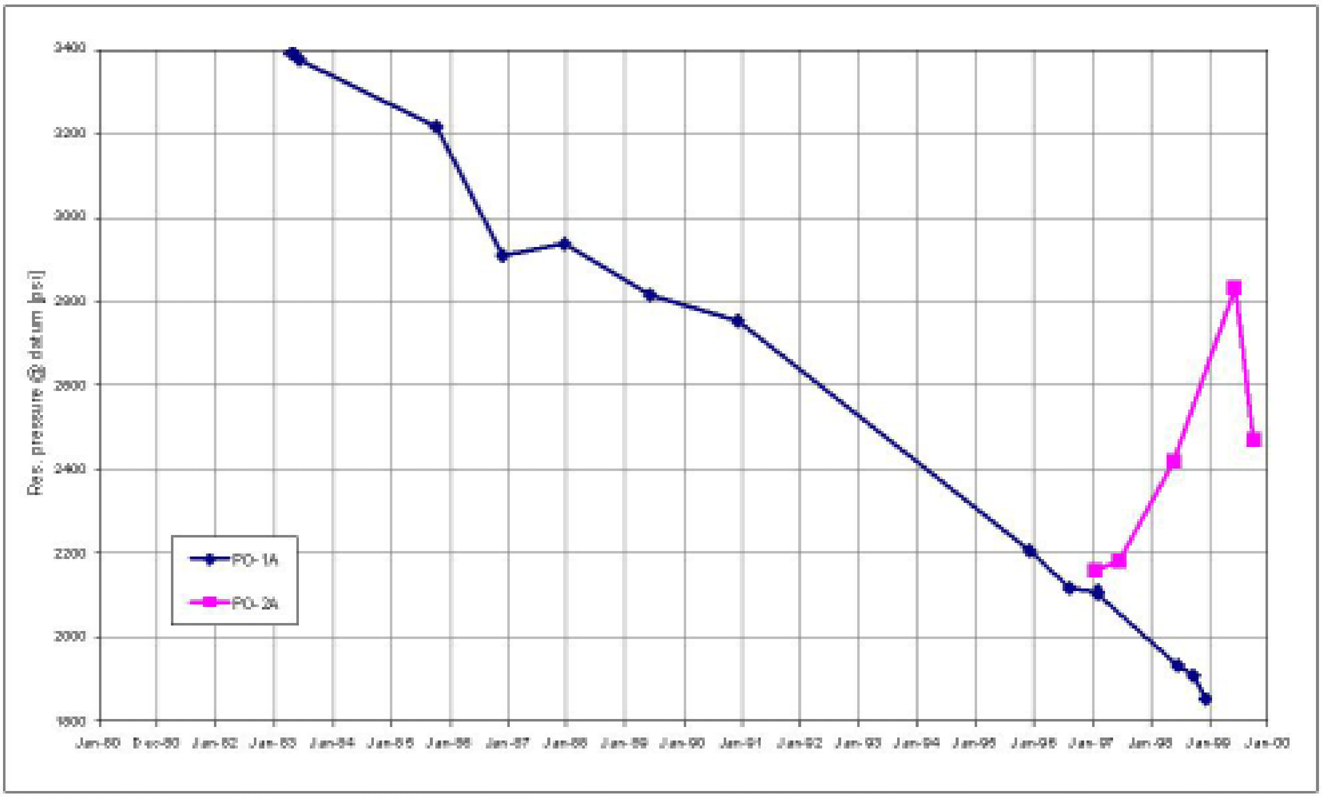

Figure 10: Pouri area pressure history.

Drilling results

The steeply dipping McKee reservoir and the narrow oil column resulted in most wells being aligned parallel to the main thrust fault, with a subsequent lack of updip wells to monitor pressure decline, fluid movements and to define the location of the thrust fault. Newly drilled wells usually resulted in an increase in the number of identified faults in the area. The presence of an aquifer or the waterflood may also have pushed oil past the last producing well. The increasing complexity requires additional wells to be drilled to confirm the presence of "attic or bypassed oil". Drilling,

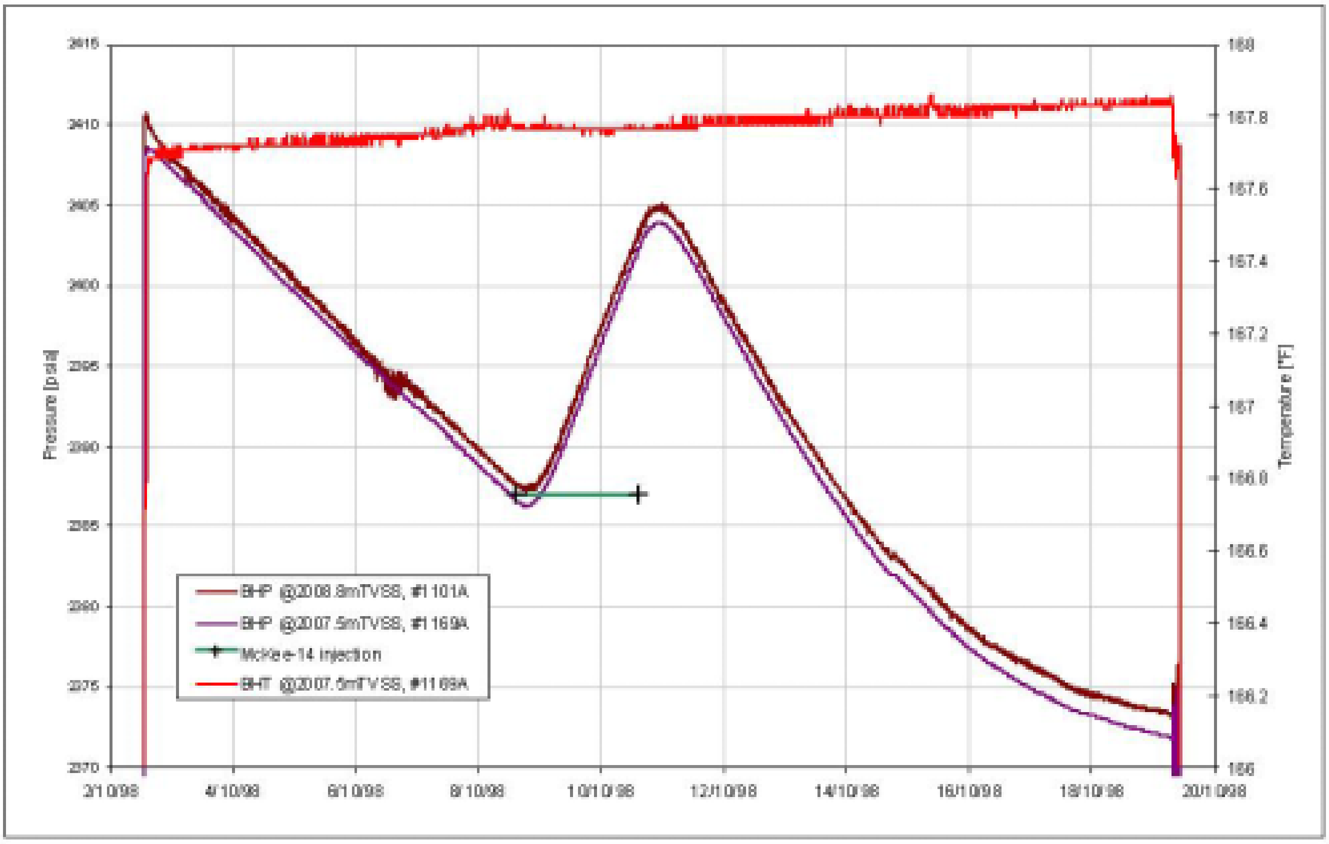

Figure 11: McKee-14 and -9 interference test results

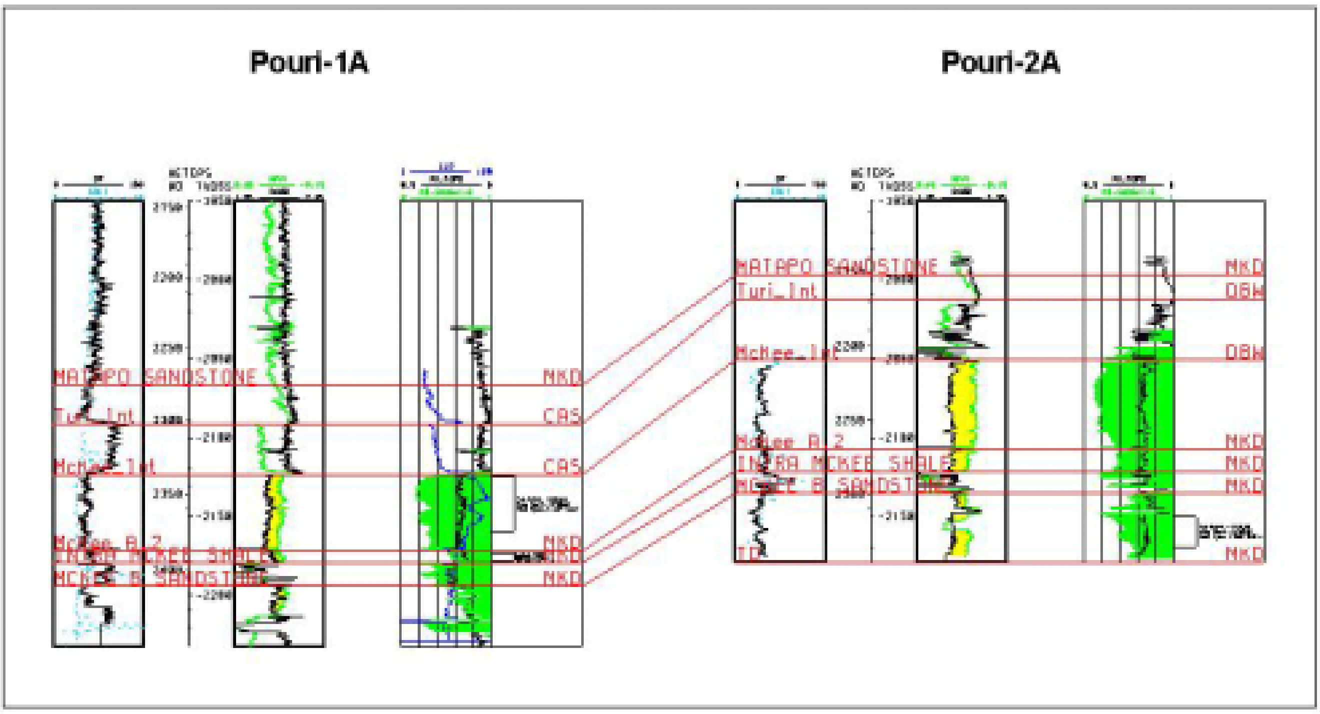

Figure 12: Pouri cross-section.

which is expensive and possibly uneconomic, appears to be the only way to determine the nature of the fluids that may be located updip. Future drilling locations will be based on individual well performance.

The ToeToe-4D well was the fifth well drilled/sidetracked from the same wellbore. The ToeToe-4A well produced significant volumes of oil before being sidetracked. Three of the initial four wellbores were abandoned due to missed geological picks from the seismic, mechanical problems or drilling into downthrown wet fault blocks. These geological/drilling problems help account for the low rate of success when picking the correct location on the first attempt.

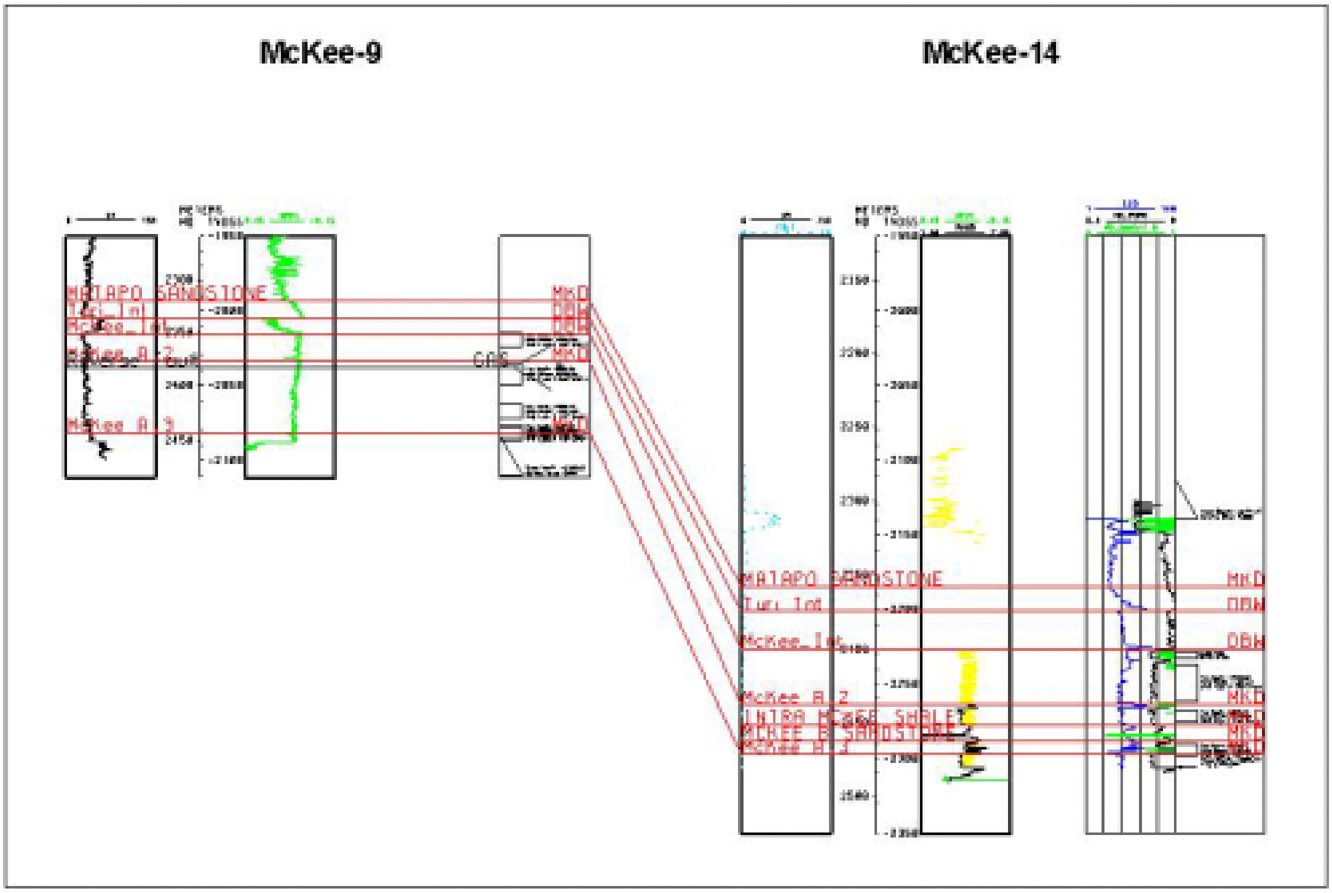

Figure 13: McKee cross-section.

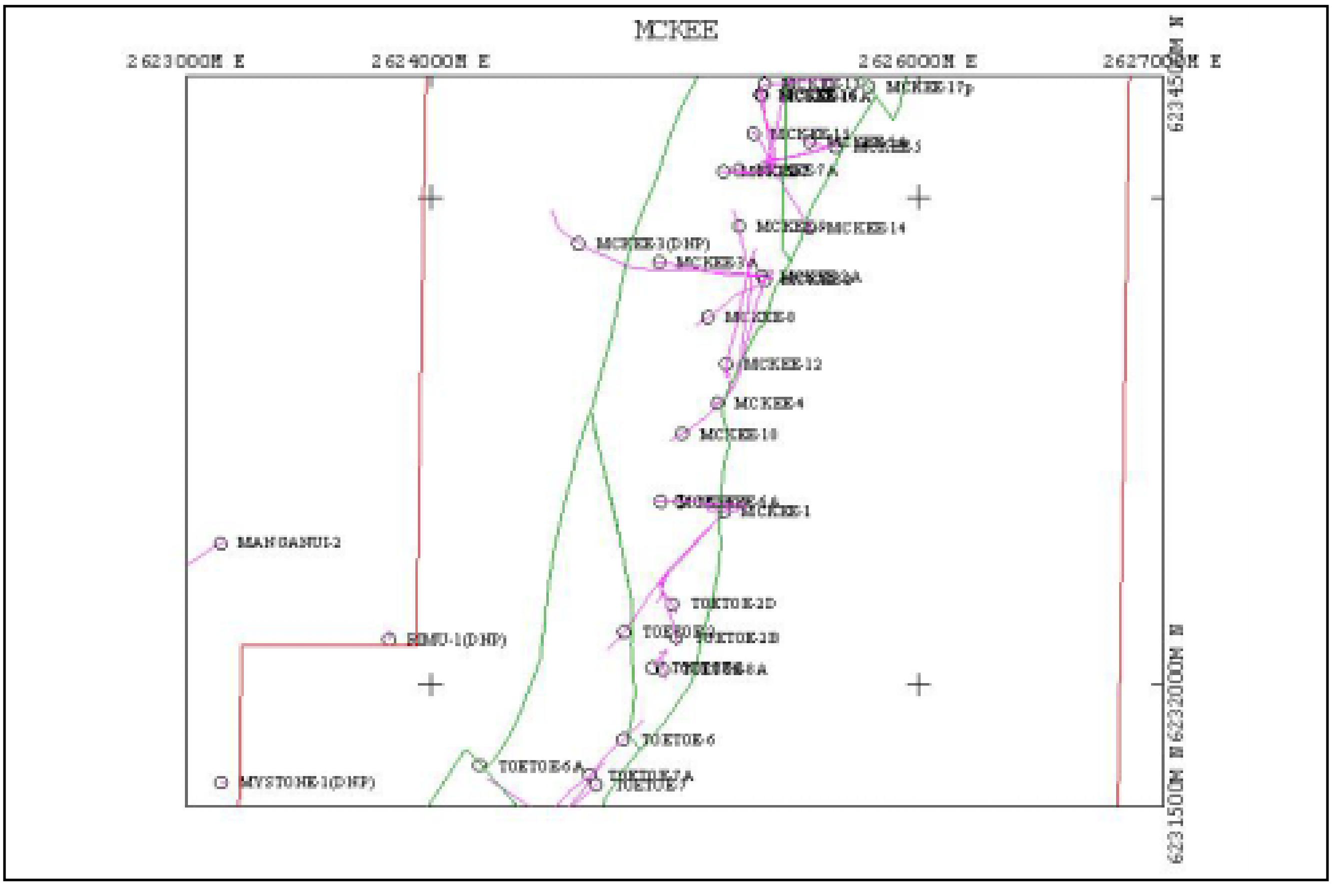

Figure 14: Central McKee location map.

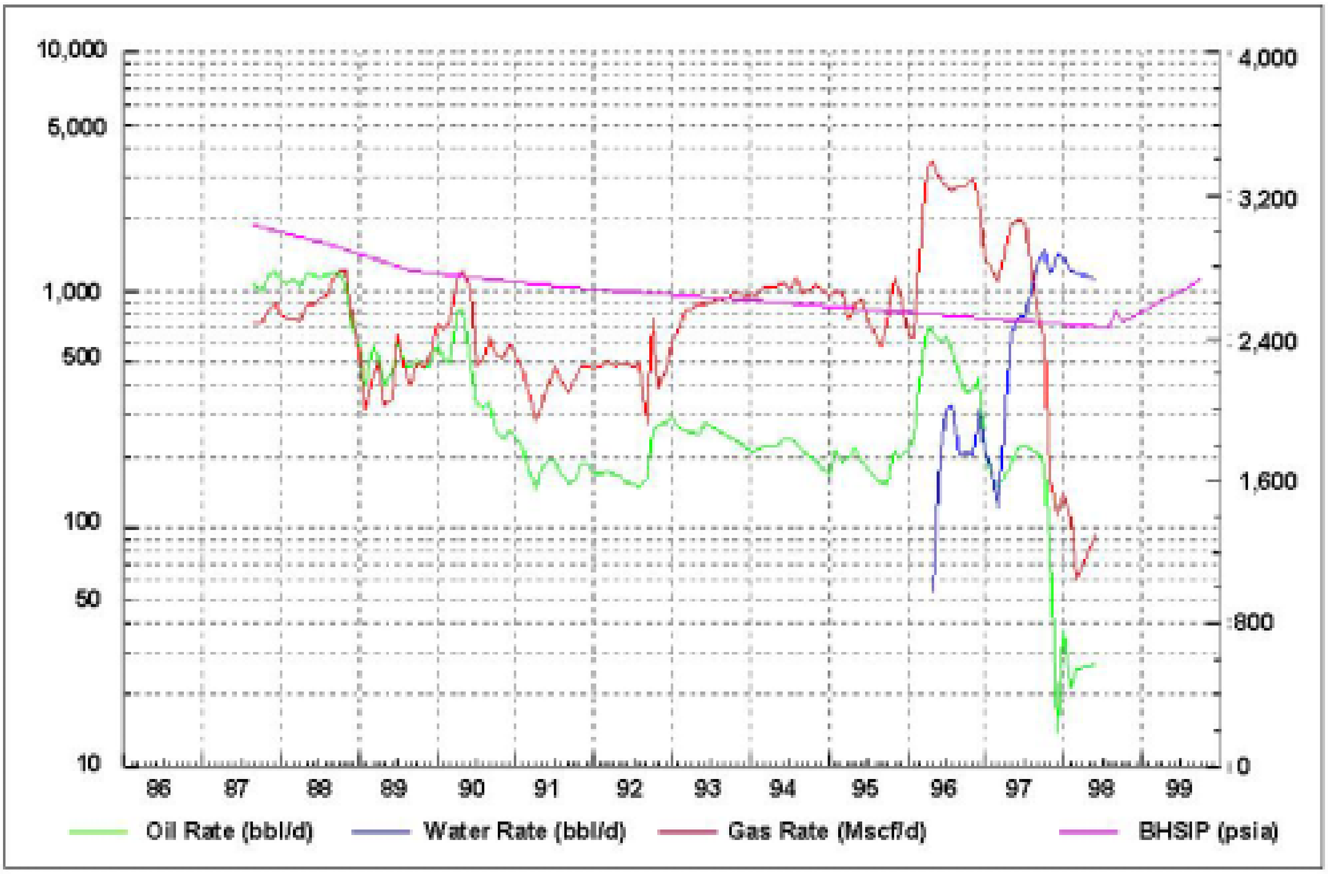

Figure 15: McKee-9 production history.

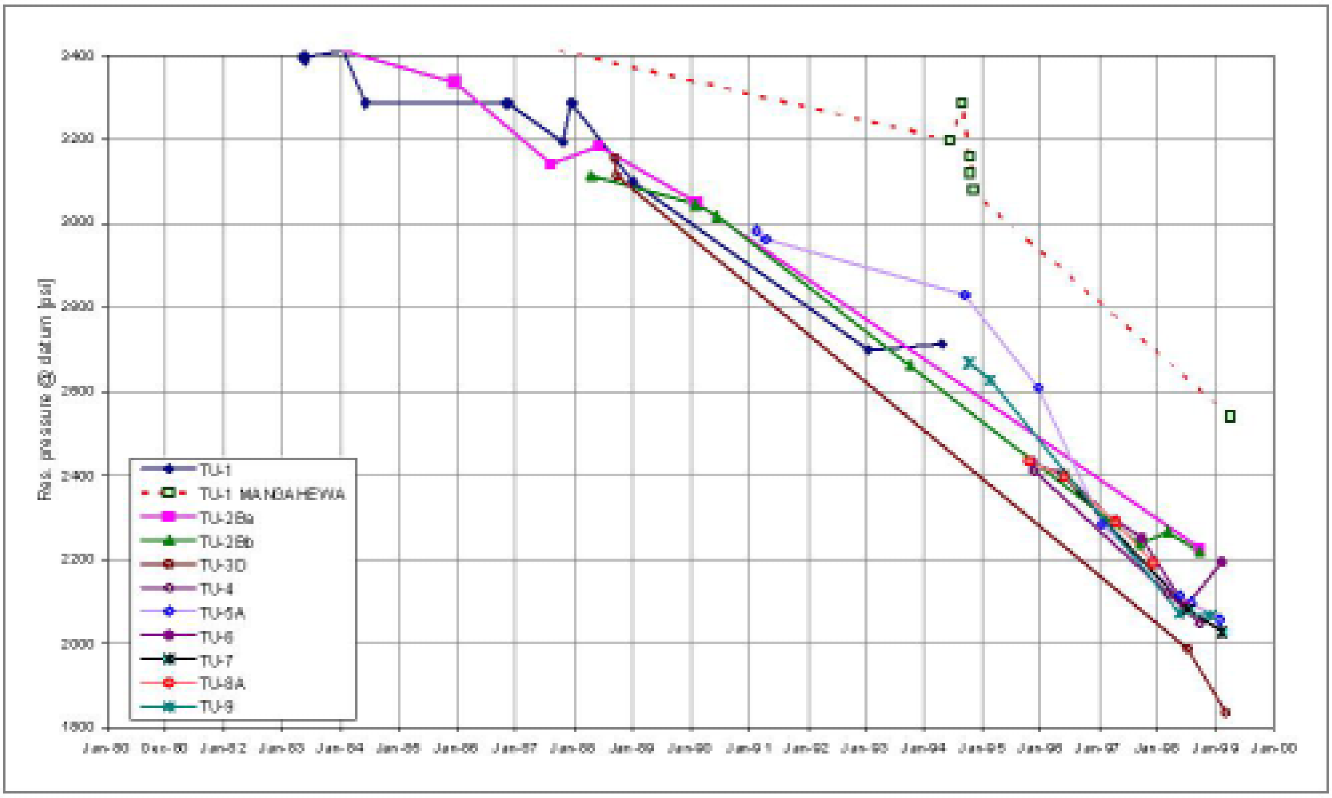

Figure 16: Mangahewa pressure decline.

The ToeToe-6B well, which was recently completed as a gas well, has provided another major "surprise". The well was originally designed to test the productivity of the upper zones, confirm the possibility of structural rollover against the major thrust fault, check the type of fluid in the Mangahewa zone and define the location of the major thrust fault in the ToeToe

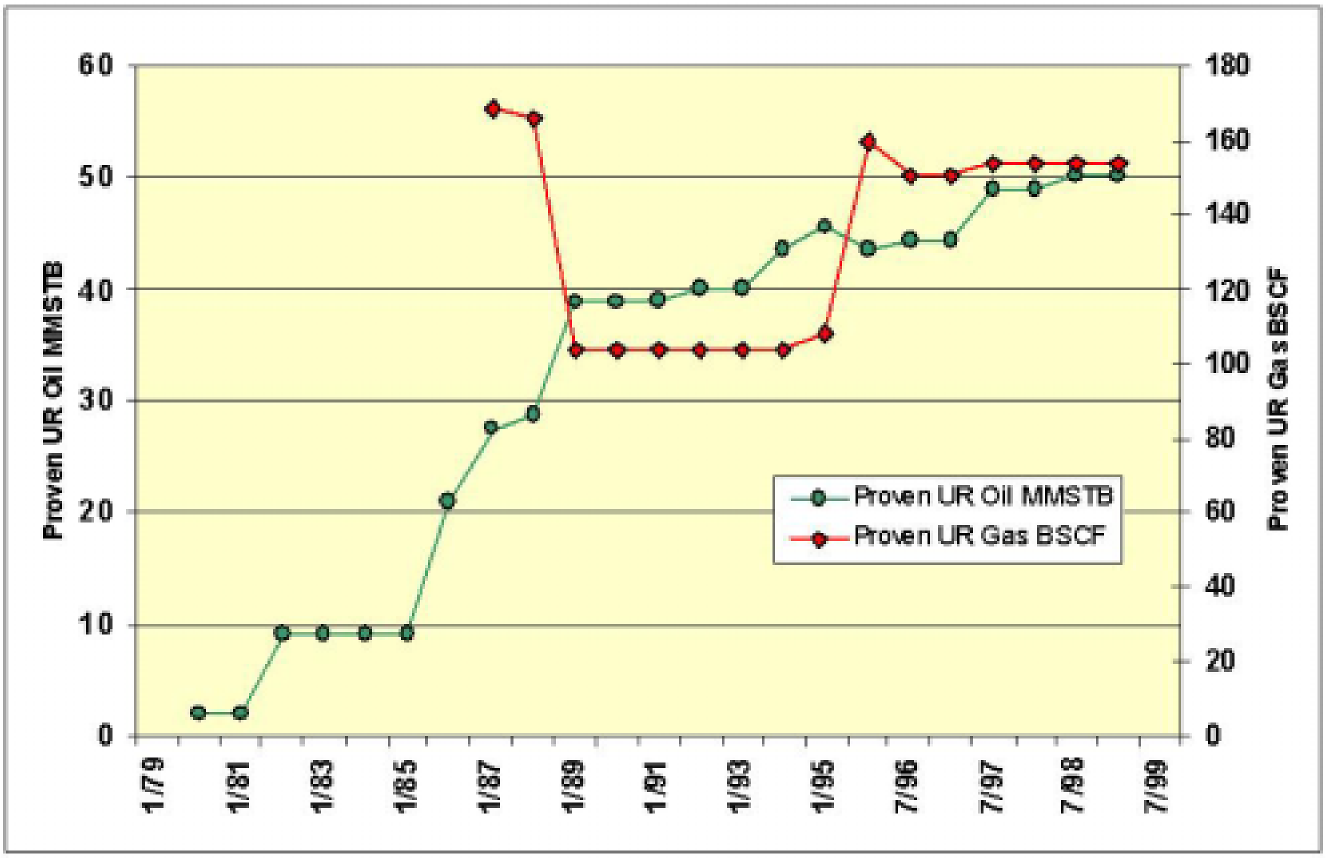

Figure 17: Oil and gas reserves history.

area. The well came in 200 m high to prognosis and was separated from the immediate downdip area by a major fault. The exact location and direction of this fault was defined by the ToeToe-6A well, which was plugged back due to drilling problems, and the ToeToe-6B well.

The pressure data from the McKee formation in ToeToe-6B proves conclusively that this area is in communication with the rest of the field. The upper zones and the Mangahewa Formation did not have any hydrocarbon shows while being drilled and appear wet and tight on the well logs.

All wells drilled into the Mangahewa Formation were either plugged back with cement or wireline plugs and completed in the McKee Formation. Testing of the Mangahewa zone was minimal and pressure data is sparse. Using wireline to pull isolation plugs, the Tuhua-1 well was recently surveyed to obtain pressure data from the Mangahewa Formation. As shown in Figure 16 the pressure has been declining over time and, at least in the Tuhua area, matches the pressure decline in the McKee Formation. Communication appears to be through either existing well bores or along natural or induced fractures. Analysis of the scale from the Tuhua-8 well indicates that the source of the water depositing this scale is from the Mangahewa Formation. Tuhua-8 did not penetrate the Mangahewa Formation.

Reserves history

The calculated amount of oil in place has remained relatively constant considering the large number of wells drilled since initial production. The field has produced in excess of 42 mmbo. Gas reserves have varied but considering the limited number of wells available to define the location and nature of the main thrust fault they have remained surprisingly consistent. Figure 17 shows the historical figures for the oil and gas reserves starting in 1980 through 1999.

There is an ongoing debate among various Engineering staff concerning the results of recent Material Balance calculations. To get a good history match it was necessary to “move” gas from various portions of the field to the Central McKee area. Data from interference tests and currently mapped faults, that apparently separate these portions of the field, do not appear to support the movement of large volumes of gas. However, the same data fails to supply an alternative source for the required gas volumes. The recent data indicating that the Mangahewa Formation may be cross-flowing gas to the McKee, in the Tuhua area, complicates the debate. The debate continues.

Summary

Use of bottom hole pressures and well test data used in isolation can be misleading and result in decisions that require constant updating. Back thrust faults may result in the formation of secondary gas caps and lead to the assumption that an increasing GOR is due to the expansion of the primary gas cap. The presence of a large primary gas cap also dampens the pressure pulses that are required for a successful interference test. Injection of cold water may result in the formation of fractures in areas that were previously confirmed as free from fractures and lead to the rapid watering out of wells. The impact of cold water injection into a reservoir containing waxy crude may result in an insulting layer (tunnel) being formed that allows cold water to move long distances before reaching reservoir temperature. Seismic surveys must take into account all existing data that may impact the design of the survey. The current approach for Field Management planning, as adopted by FCE, is the formation of an Integrated Multi-discipline Team. The team is composed of Engineers, Geoscientists, Operational personnel and Technicians who meet frequently to discuss the available data, review the impact of any new data on the existing plan, request specific data gathering activities and recommend future actions.

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References

WOR and GOR Derivatives. Christine Coppell and David Waghorn, FCE.

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