

Mangahewa Gas Programme

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Abstract

The Mangahewa Gas Programme involves the exploration, appraisal and potential development of gas-condensate reserves trapped in the Mangahewa Structure in northern Taranaki. The structure is a large north-trending inversion anticline and gas is reservoirised in Eocene Mangahewa Formation sandstones at depths of 3300 m and greater, sealed by intraformational shales. Reservoir sandstones have been more deeply buried than at present and hence have low porosity and permeability.

Early wells that penetrate the reservoir formations indicated that the sandstones will not yield hydrocarbons at commercial rates without application of enhanced recovery techniques. The Mangahewa-2 well was spudded at the end of 1996 in a crestal location to test the viability of hydraulic fracturing as a method of recovering hydrocarbons at economic rates. The well penetrated a thick sequence of Mangahewa Formation sandstones, shales and coals below 3300 m TVDSS. The sandstones were "tight" as predicted and gas and condensate were indicated over a gross interval of 840 m.

Provisional hydraulic fracturing designs were finalised before drilling commenced to determine materials and equipment requirements. Mobilisation of fracturing equipment and materials began before drilling had ceased with equipment and materials coming from United States, Brunei and Malaysia. Fracturing expertise was drawn from Canada, Australia and the local workforce. Three intervals were selected for fracturing, which began on 1 May and was concluded within 30 days. Each fracturing job was preceded by a mini-frac to gather data. Initial job designs were modified based on this data.

The three intervals were subjected to short-term testing between June and August before the top two zones were commingled and put on long-term test from September 1997. This testing is likely to last until the end of July 1998 and is intended to demonstrate well productivity and drainage volume.

An appraisal programme, designed to evaluate the field extent and, in the event of continued success, to allow early development and production from the field, is in progress. The initial phase of the programme comprises two appraisal wells, which will be drilled in 1998, and a large-area, sparse-grid 3D seismic survey, which is being acquired in two phases. Future appraisal well locations and seismic acquisition will depend on the results of the current programme.

Introduction

The Mangahewa Gas Programme involves the exploration, appraisal and potential development of the gas resources trapped in the Mangahewa Structure in northern Taranaki (Figure 1). The programme was developed after the successful drilling, hydraulic fracturing and long-term testing of the Mangahewa-2 gas discovery well. This well was the product of a regional in-house study, which was intended to investigate the potential of the Kapuni Group of the onshore Taranaki Basin.

This paper gives details of the operations at the Mangahewa-2 wellsite that led to the long-term commercial flow that is set to continue until August 1998. The results of drilling are reviewed before the hydraulic fracturing operations are discussed in some detail. Sustainable commercial flow rates in short-term testing at Mangahewa-2 led to installation of production testing facilities, which enabled long-term testing to continue without the need to flare large volumes of gas to the atmosphere.

MANGAHEWA FORMATION/MAUI SANDS Gross Depositional Environments

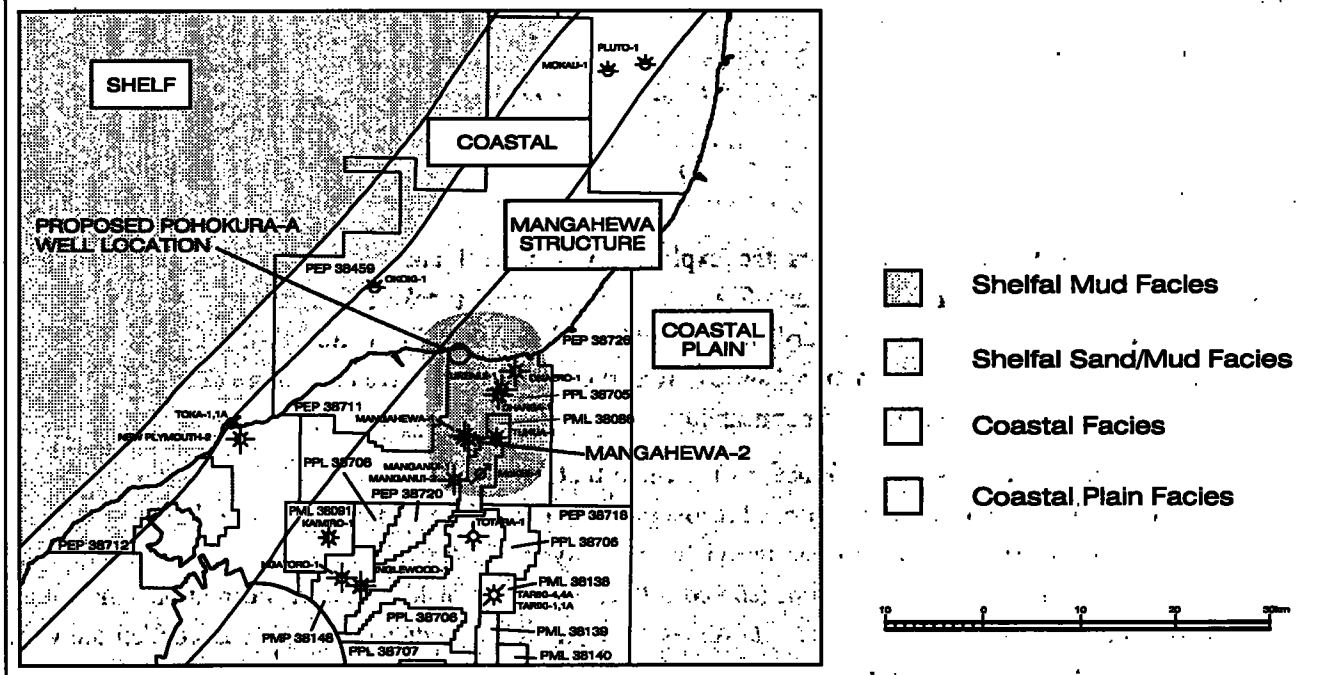


Figure 1. Mangahewa Structure (red) location map.

Following successful testing an appraisal programme was formulated to enable the rapid and cost-effective production establishment of reserves volumes and geographic distribution, which will lead to first commercial gas sales potentially as early as the end of the year 2000. The details and rationale for this appraisal programme are discussed as are the criteria for the selection of seismic survey and well locations.

Mangahewa-2

The Mangahewa-2 exploration well was the product of an internal Petrocorp (now Fletcher Challenge Energy Limited (FCE)) review, entitled the "Deep Gas Project". This study was commissioned in 1994 with the remit to evaluate the deep gas potential within the Kapuni Group of the Taranaki Basin. To date the vast majority of gas and oil production in the Taranaki Basin has come from the Kapuni Group, which is the productive gas-condensate reservoir interval in the Maui and Kapuni fields and the productive oil and gas reservoir in the McKee Field. Much of the Taranaki Basin is underlain by Kapuni Group sedimentary rocks, although, in some areas, these are too deep for current interest for hydrocarbon exploration.

The Deep Gas Study reviewed the hydrocarbon potential of the Kapuni Group and a focus developed on its potential in the onshore area of northern Taranaki. A number of well penetrations had encountered the Kapuni Group, although few of these penetrations were extensive.

Gas shows had been encountered in some of these wells but no commercial production had been established. The principal reasons for this lack of commerciality were:

- 1 Current depth of reservoirs
- 2 Maximum depth of burial of reservoirs
- 3 Deltaic reservoir facies
- 4 Suboptimal drilling and completion practices

Most of the Kapuni Group interval in the northern part of Taranaki lies at current depths in excess of 3 km. The only significant exceptions to this are in the Tarata Thrust Belt, which contains the McKee Thrust, which traps the McKee Oil Field. The majority of reservoir penetrations in the area penetrate Kapuni Group reservoirs in a deltaic environment. Sandstones in this environment have a higher shale content than the relatively clean quartzose sandstones of the laterally equivalent coastal and shallow marine facies Maui C Sands in the Maui Field. As a result the deltaic sandstones have poorer initial reservoir quality, which is exacerbated by Miocene burial to depths about 1 km greater than the present day depths.

The Kapuni Group interval in northern Taranaki comprises "tight" gas reservoirs, ie, low porosity and permeability sandstones. Such tight reservoirs have been the focus of significant attention in the hydrocarbon industry since the early 1970s, particularly in the United

States, where considerable research and technological development has taken place. As a result the United States currently has significant reserves in "tight gas" reservoirs and has developed significant expertise in rendering hydrocarbons in such reservoirs available for commercial production. It was one conclusion of the Deep Gas Study that the deep Kapuni Group sandstone reservoirs should be the subject of these new technologies.

The study also identified the Mangahewa Structure, which is a large 20 km (N-S) by 10 km (E-W) inverted anticline located about 20 km east of New Plymouth (Figure 1). The structure is a simple, low-relief anticline, created by Miocene inversion on a north-trending regional fault to the west of the structure called the Lepperton Fault. The structure comprises in situ Kapuni Group sedimentary rocks, including potential sandstone reservoirs in the Kaimiro, Mangahewa and McKee formations. The in situ structure underlies the overthrust McKee Structure, which thrusts Mangahewa and McKee formations over the in situ reservoirs.

The Mangahewa-2 well was proposed in early 1996 and a site (Mangahewa-A) was selected on Otaroa Road, Tikorangi about 3 km north of the McKee Production Station (Figure 1). The site was chosen because it lies above the crest of the in situ Mangahewa Structure to minimize the risk of geological failure and to penetrate sandstones with maximum gas saturations. The site is close to an existing well, Mangahewa-1, which had been plugged and abandoned with subcommercial gas shows by Shell-BP-Todd in 1961. It is also adjacent to an existing but redundant 4" gas export pipeline (between McKee Production Station and the McKee Mixing Station at Tikorangi), which could be used for gas export in the event of success.

Drilling

The well was spudded with the Parker 188 rig on 15 December 1996 and reached final TD of 4376 m MDBRT (4246 m TVDSS) on 10 February 1997. The rig was released on 25 February 1997 after 72 days on location. The well penetrated the Kapuni Group interval at a depth greater than 3300 m TVDSS and penetrated a gas-bearing interval of approximately 840 m, of which about 65% (546 m) were sandstones of varying qualities. Four cores were taken in the Mangahewa Formation interval, together with an extensive wireline logging programme, including the first use in New Zealand of the NUMAR MRIL-C nuclear magnetic resonance tool. This tool was used to address issues of water saturation and permeability in the tight gas reservoirs.

Geological and petrophysical evaluation of the sandstones penetrated in the Mangahewa Formation confirmed that hydrocarbons were present. Detailed wireline log evaluation, including saturation and permeability interpretation of the MRIL log, were combined with

information derived from core plugs from the 4 cores taken within the sandstones. Detailed core analysis was undertaken to confirm reservoir characteristics. Sandstone reservoir quality was within the expected ranges of porosity (8-12%) and permeability (0.01 to 10 mD). A number of reservoir intervals were identified for perforation and hydraulic fracturing and three were chosen for treatment. The lowest candidate zone was perforated on 25 February 1997 by tubing-conveyed perforating guns whilst the rig was on still on location. The zone flowed but disappointingly on initial test. Rates of less than 0.2 MMSCFD were estimated for the gas flow. A coiled tubing unit was used on 19 March 1997 in an attempt to enhance flow by nitrogen lift but this was ineffective and the well was shut in pending the arrival of hydraulic fracturing equipment.

Hydraulic fracturing

Hydraulic fracturing is a production enhancement technique, now commonly used to stimulate tight and fractured oil and gas reservoirs. Its use is well-established, particularly in the onshore United States, but it has had limited application in New Zealand. Petrocorp used the technique in the Kaimiro-1 well in 1993. The Kaimiro-1 well is located about 20 km southwest of Mangahewa-2. The Kaimiro-1 well was stimulated by hydraulic fracturing but the well never achieved commercial flow rates, although there is some debate over the causes for the lack of commercial flows (Yang *et al* 1996). Shell Todd Oil Services have also used hydraulic fracturing as a stimulation technique in wells in the Mangahewa Formation of the Kapuni Field.

Stated simply the hydraulic fracturing process involves the pumping of fluids at high pressure into a target reservoir perforated interval to exceed the fracture strength of the reservoir and cause an artificial hydraulic fracture to form. Once this fracture has been initiated, a medium, called proppant (usually some kind of medium-grained sand) is pumped into the fracture to prop it open when the pumping is stopped (Figure 2). The placement of proppant in the fractures is assisted by the use of cross-linked gels. These are usually starch-based solutions, which are liquid at the surface but, with time and temperature, form long-chain polymer bonds and thus become like gels just before entry into the formation. Once in the formation these gels "break" back to a liquid state, so that they can be flowed back to surface without disturbing the proppant wedge, trapped in the hydraulic fracture. With continued flow, formation fluids should be drawn into the fracture, through the perforations into the wellbore and thence to surface.

The decision to use hydraulic fracturing as a production enhancement technique on Mangahewa-2 reservoirs was made before the well was spudded. FCE engineers worked in conjunction with hydraulic fracturing experts from Halliburton (the equipment contractor) and Resources Engineering Systems of Cambridge,

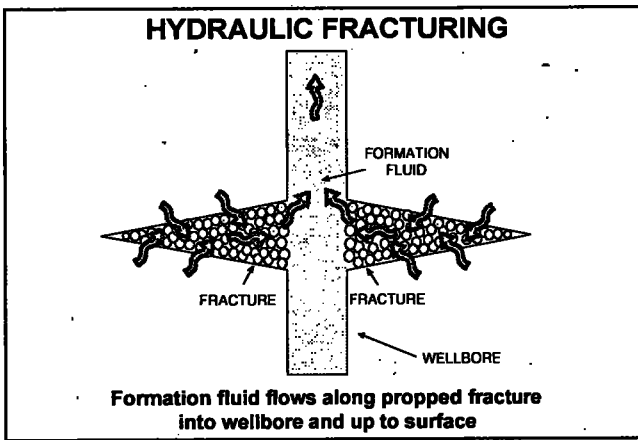


Figure 2.

Massachusetts, the fracturing consultants. Together they modelled the likely hydraulic fracturing requirements for the anticipated reservoirs by computer simulation.

Decisions were made about the type and number of pumping units that would be required, the choice and specifications of proppant and gels and manpower requirements were established.

The final ordering of materials and equipment did not occur until after drilling had been completed and FCE was confident that the hydraulic fracturing was warranted. Orders were placed in mid-February 1997 for 400,000 lb of proppant (a corundum-based artificial sand, called Carbolite was selected). Orders were also made for appropriate volumes of spacer sand (to isolate zones between fracturing operations) and sufficient chemicals to pump the two projected fracturing jobs. This led to a three-month delay before the fracturing operations could occur. This delay had been factored into the programme and the interim period was used for a revision of the computer simulations of fracturing in light of the newly available data from the well. Further, the delay allowed all logistical issues involved in assembling a hydraulic fracturing "spread" in a remote location such as New Zealand to be addressed. Halliburton's equipment came from the United States, Brunei, and Malaysia, whilst the materials came from the USA and Australia.

Hydraulic fracturing is an expensive activity and a decision to limit cost by expedient use of the equipment was taken. The need for pre- and post-frac flows of perforated zones was compromised to avoid having the fracturing equipment and crews on standby. As a consequence there was a strong operational focus driving early use and discharge of the equipment and crews. This focus is understandable in light of the experimental nature of the fracturing operations. The operational plan required hydraulic fracturing equipment and crews to be on location for 31 days.

A target date of 1 May 1998 was set for the start of hydraulic fracturing. All the fracturing equipment was assembled at the site during the last two weeks of April

together with test separators and product storage tanks. Equipment checks delayed the start of operations until 3 May.

Each fracturing job comprises an initial "mini-frac" (sometimes called a "data frac"), during which various pumping tests are conducted to gather information about the reservoir and its likely performance under full fracturing conditions. A small, initial fracture is created at the end of the mini-frac and is packed with a small volume of proppant. Information gathered from the mini-frac is then evaluated in computer simulation and the final programme is revised accordingly. This information review generally takes about 1-2 hours, where historical data is available. At Mangahewa no historical data was available so the review and simulations generally lasted about 24 hours. The final pumping job for each reservoir zone therefore generally occurred 48 hours after the mini-frac for that zone.

The deepest zone (perforated whilst the rig was still on site) underwent a mini-frac on 3 May 1997. The main frac in this zone was conducted on 5 May with 140,000 lbs of proppant pumped. The well was flowed from 8 May to 14 May. The well demonstrated poor post-frac flow performance during this period with peak flow achieved at a rate of 1.57 MMSCFD of gas at a flowing pressure of 600 psia on a 24/64" choke. The zone also produced 36 BCPD and 216 BWPD.

Whilst this flow test was in progress rigorous examination of the results and comparison with original computer simulations led to the view that the remaining proppant could better be distributed between two further fractured zones than one. This would increase the chances of a final commingled flow rate achieving economic thresholds.

Accordingly the second (middle) zone was perforated by wireline-conveyed through-tubing perforating guns on 14 May 1997. This perforated but unfractured zone was then commingled with the lower fractured zone and achieved high initial rates on clean-up. The lower zone was then sanded off (to isolate the lower perforations) on 18 May. The middle zone was subjected to mini-frac treatment on 19 May and again results were incorporated into revision of the main fracturing schedule. The main fracture treatment was pumped successfully on 21 May and the well was flowed briefly on clean-up but no rates were recorded.

The well was cleaned out to below the lowest perforations using the Coiled Tubing unit to enable the top zone to be perforated by wireline-conveyed through-tubing guns on 24 May. Following this perforation the well was allowed to flow from all three zones (the upper zones still in clean-up phase) and an instantaneous flow of about 8 MMSCFD of gas a day was achieved. The well was then shut in to enable three sand plugs to be pumped to isolate the lowest and middle perforated intervals, prior to hydraulic fracturing of the top zone.

The top zone was subjected to mini-frac treatment on 30 May and the main fracture treatment was pumped on 31 May after which the hydraulic fracturing equipment was rigged down and demobilised to Australia.

Testing

The testing programme envisaged a period of short-term testing of each zone followed by longer-term testing to establish commercial viability of each zone. The use of sand plugs to isolate zones prevents the testing of individual zones (except the top zone) and thus commingling of the lower zones is necessary. Testing occurred in reverse order to fracturing.

Short-term testing

Short-term testing of the top zone extended from 1 to 30 June during which flow reached a peak of 3.3 MMSCFD at a flowing pressure of 2750 psia on a 14/64" choke. The well also produced 60 BCPD (45-47° API) and 180 BWPD. The zone was then shut in for a build up during July but failure of down-hole gauges required a further flow and build up from 17-31 July 1997.

The sand covering the middle zone perforations was removed using coiled tubing lift and the upper and middle zones were flowed in a commingled state. This commingled test lasted from 18 August until 13 September 1997 and finally achieved attractive flow rates (Figure-3). The two zones were flowed commingled at three different choke settings and the results for each is summarised in Table 1.

During these tests a total of 0.2 BCF of gas, 2942 BBLs of condensate and 473 BBLs of water were produced. The condensate-gas ratio was 12.60 BBLs/MMSCF and the water-gas ratio was 2.30 BBLs/MMSCF. Gas

Gas	FTHP	Choke	Condensate	Water
MMscfd	psia	inches	BCPD	BWPD
7.4	4930	14/64	82	12
11.4	4750	18/64	140	25
17.5	4450	24/64	230	45

Table 1. Middle and Upper Zones short-term testing. FTHP = flowing tubing head pressure.

composition was dominantly methane with about 3.5% CO₂ and 0.5% N₂. Condensate gravity was 47° API. The gas was flared, condensate trucked to McKee Production Station and water trucked to an approved disposal well.

The well was shut in on 13 September for a build-up, which lasted until 29 September, after which testing equipment was rigged down.

Long-term testing

The success of short-term testing of the two zones led to the decision to put the well on long-term production test. FCE staff worked to a very tight timetable to design, fabricate, install and commission a semi-permanent production facility that would enable the two upper zones to be tested without the requirement to flare gas but rather to pipe it to an end-user. With the help of local contractors facilities were fabricated from redundant and rental equipment and commissioned on 5 December 1997.

The facilities include three separators and two gas heaters (Figure 4). Long-term testing began on 5 December 1997 and continues up to the time of the conference (ie, approximately four months continuous flow). The test results are confidential but the well has flowed consistently at rates of approximately 17 MMSCFD with about 225 BCPD and 36 BWPD. The gas and condensate compositions remain stable and pressure decline has been

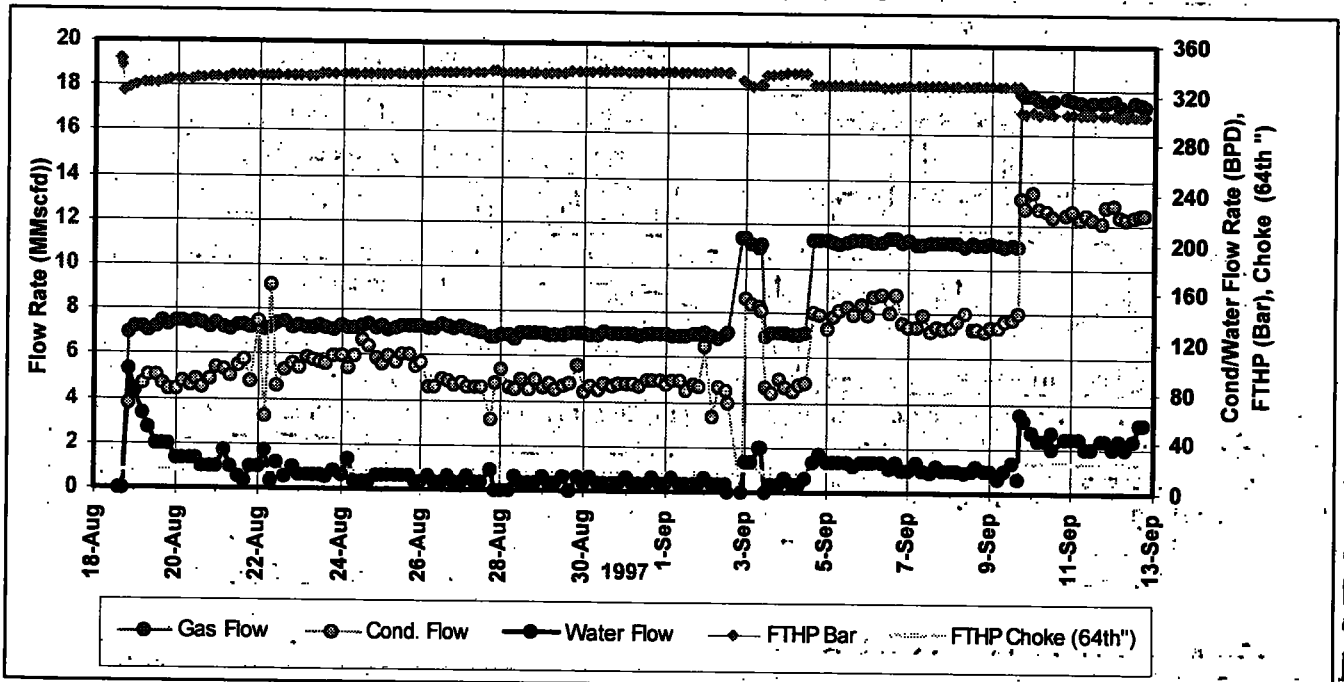


Figure 3. Middle and Upper Zones short-term testing.

slight. The long-term tests are scheduled to continue until at least August 1998:

Appraisal Programme

After the successful conclusion of the short-term testing, decisions were taken to commence an appraisal programme to appraise the Mangahewa-2 discovery and the potential reserves in the Mangahewa Structure.

The appraisal programme was devised with the following objectives:

- Determine the field extent and establish a field core
- Acquire a 3D seismic survey over the structure and define the internal geometry of the Mangahewa Formation interval
- Drill up to eight appraisal/développement wells
- Optimise production enhancement techniques (such as hydraulic fracturing or deviated wells)
- Minimise long-term testing
- Early submission of a Petroleum Mining Permit application

The appraisal programme was devised in conjunction with the obligatory work programmes for the PPL 38705, PEP 38459 and PEP 38711. A new permit, PEP 38726, was applied for under the Acceptable Frontier Offer scheme, to enable the eastward extension of the proposed 3D seismic survey.

3D Seismic Survey

A 3D survey of the Mangahewa Structure was commissioned in November 1997. A scoping design led to the establishment of a "sparse-grid, wide aperture" survey (Bouska 1997), which encompasses a surface area of 322 km² with full-fold coverage over an area of 263 km² (Table 2).

The objectives of the 3D seismic acquisition can be summarised:

- Constrain the geological model for sand and thus reservoir distribution
- Enable a detailed stratigraphic interpretation of the Mangahewa Formation reservoir interval
- Enable seismic attribute data to be tied to well data
- Better and earlier prediction of reserves
- Earlier development decision

The survey was approved in early November and land access permitting began in mid-November.

	Sources	Receivers
Line Spacing	720 m	480 m
No. of Lines	26	39
No. of Shotpoints	8248	-
Receivers/Line	-	300
No. of Receivers	-	10,872

Table 2. 3D seismic survey parameters.

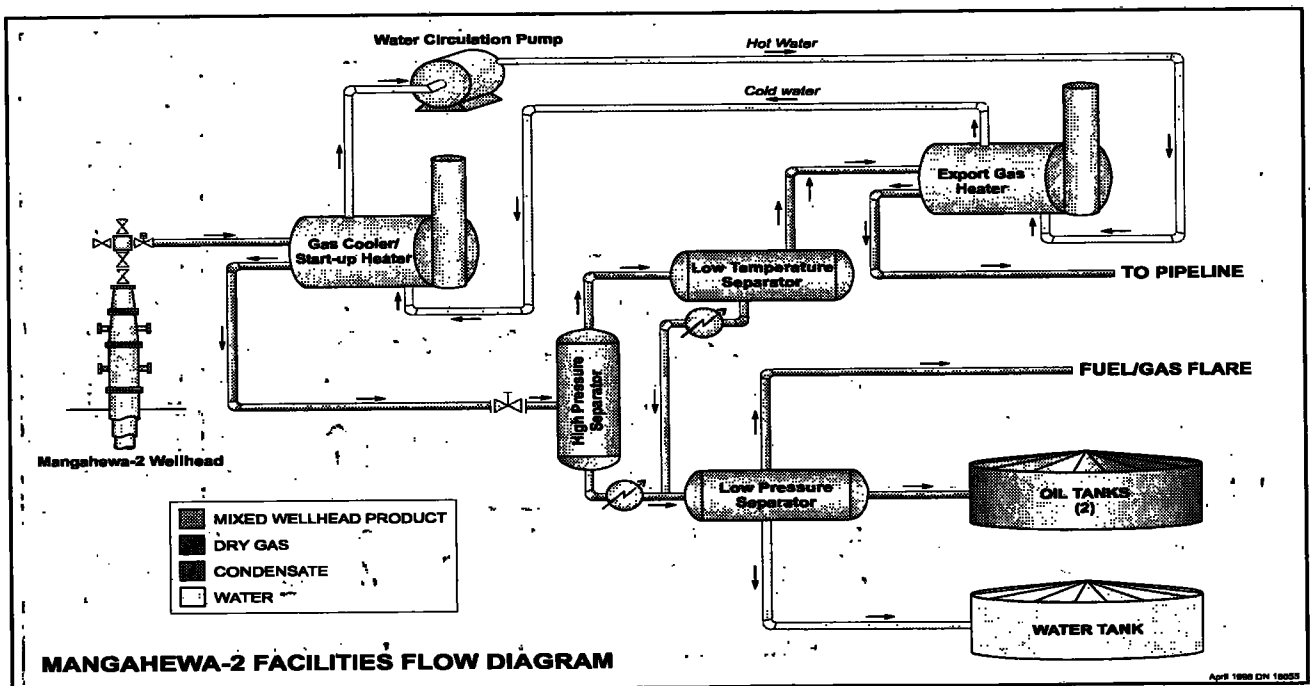


Figure 4. Schematic of Mangahewa-2 test facilities.

Because the width of the survey is 18 km, it is too large to shoot in one pass. The survey was also commissioned rather late in the season, given that ground and weather conditions prevent land access between May and August. Therefore the survey was split into two halves. Although this requires an area of overlap to be shot and recorded twice, the benefit is that half the survey area could be recorded in the 1997-98 season. The western half was chosen to be shot first because topographic and land use conditions are easier in the western area so the survey should be recorded more quickly. The western area is also the likely site of early appraisal wells so early 3D seismic data could be tied with well penetrations from early wells.

Land access permitting for the western area began in late November and was a major exercise, given that 612 properties had to be permitted. Both computer and GIS databases had to be constructed and populated to enable five permitting officers to go out in the field to gain land access.

Surveying began on 13 December 1997 and was completed on 10 March. GPS base stations were set up to avoid the need for theodolite surveying. Four crews were employed in open agricultural areas and two were employed on surveying in the bush. Two bush cutting crews were also necessary to clear access in bush areas and lay ropes for access in steep terrain.

Shot-hole drilling began in late December 1997 and was completed on 24 February with over 3700 holes having been drilled. The majority of shot-holes was drilled to depths of approximately 25 m and loaded with 2 Kg charges.

Recording began on 11 March 1998 and by the time of the conference was 45% complete. Recording began in the southeastern corner of the area with helicopter support to enable cable laying. The recording phase was delayed due to weather downtime, technical problems with recording equipment and vandalism and theft of equipment. These last issues were not anticipated since little vandalism or theft has occurred on recent previous surveys. Nonetheless, following the Greenpeace protest on 16 March 1998, where equipment was removed by Greenpeace protesters, there has been persistent small-scale vandalism to seismic equipment.

At the time of writing with recording of the western half of the 3D survey less than 50% complete, it is too early to assess data quality accurately. However, another feature of this survey is the use of in-field processing so that early processing takes place overnight. Data quality (from single shot records) appears to be moderate-to-good. Stacked data from early shot records should be available before the survey recording is complete. In-field processing will also be used to assist the final processing contractor in developing and optimising his processing stream and it will enable preliminary interpretations to be

made ahead of the final processed data volume being available.

The eastern half of the survey will be acquired between September 1998 and March 1999 so that the final processed whole-survey data volume should be available for interpretation by mid-1999.

Appraisal drilling programme

The appraisal programme envisages the drilling of up to eight appraisal/development wells over the next three years (to end-2000). At least two of these wells will be located and drilled without the benefit of the new 3D seismic data being available to assist in the choice of locations. The purpose of the drilling programme is to establish the size of the hydrocarbon accumulation, to determine the distribution of producible hydrocarbons and validate and modify the current geological model for reservoir distribution. Secondary considerations are the testing and selection of appropriate enhanced recovery techniques, such as hydraulic fracturing, deviated wells or multi-lateral wellbores.

Criteria for the selection of wellsites were developed from the objectives of the appraisal programme and include both surface and subsurface considerations. Wellsite selection is important given that most of the northwestern part of the potential field area lies in good agricultural land. Consideration has been given to the impact on local communities, although given the difficulty in locating sites, those that are selected should, where possible, be available as multiple wellhead sites.

The criteria for wellsite selection are:

- Value of information
- Technical risk/reward trade-offs
- Location of existing seismic lines (until the 3D data becomes available)
- Existing licence and permit work obligations
- Negotiated land access
- Proximity to existing gas pipeline infrastructure.

By applying these criteria 10 wellsites were provisionally identified, from which two were chosen as candidates for drilling during 1998-99. To date consents for two of these sites have been submitted and consent applications for a third site are being prepared. The first of these wells is described in some detail.

Pohokura-A

The Pohokura-A wellsite lies about 1 km due east of the Methanex plant at Motunui. The wellsite lies about 200 m south of the coastline just behind the present-day seacliffs.

The site is sheltered to the north and east by trees and is accessible from the west by paved road and farm track. It is relatively isolated from the sparse and dispersed housing on the coastal plain. The site is favourable as it lies on an existing 2D seismic line and is close to the Motunui plant, requiring only a short flow line in the event of successful hydrocarbon testing. The site is close to sensitive pa and urupa sites of Ngati Rahiri Hapu and extensive consultation has and is still taking place with the hapu to avoid impact on these sites.

The well will be drilled as an S-shaped deviated well such that the Mangahewa Formation reservoir section will be penetrated in vertical hole (to maximise penetration of the flat-lying sandstones). The wellbore will be deviated 500 m north-northeast of the surface location into the offshore area and the well will fulfil a work programme obligation for the offshore permit, PEP 38459. As with Mangahewa-2, an extensive coring and wireline logging programme is planned to maximise information recovery from this appraisal well. Hydraulic fracturing, short-term and long-term testing will be conducted as appropriate.

Summary

The Mangahewa-2 gas-condensate discovery has led to the establishment of an ambitious and comprehensive appraisal programme, including acquisition of one of New Zealand's largest 3D surveys (and certainly its first appraisal 3D survey) together with a large-scale deep well drilling programme. To date the programme has involved some innovative approaches to the rapid and cost-effective exploration and appraisal of this potentially large reserve volume. These include:

- 1 Use of MRIL-C logging tool
- 2 Successful large-scale hydraulic fracturing
- 3 Rapid installation of semi-permanent production testing facilities
- 4 Large-area, sparse grid 3D seismic survey
- 5 In-field processing of 3D data
- 6 Major emphasis on land access and community consultation

Author

Dr John Huckerby joined Petrocorp Exploration Limited in 1995 after working in the North Sea, Eastern Europe and United States for Amoco. He worked in Petrocorp's Offshore Exploration Joint Venture, where he contributed to the drilling of the Awatea-1 well in the offshore Taranaki Basin. Since 1996 he has managed a team responsible for the drilling, fracturing and testing of the Mangahewa-2 discovery well and the formulation and execution of the appraisal and development programme for the Mangahewa gas resource.

The future programme will involve the use of further innovative and cost-effective techniques as they become appropriate. The Mangahewa Gas Programme is a large-scale and ambitious programme to develop the Mangahewa gas reserves for commercial production early in the twenty-first Century to complement the decline in existing New Zealand gas production.

The keys to successful appraisal and development of the Mangahewa gas-condensate reserves are:

- Understanding the hydrocarbon distribution
- Understanding the distribution of producible reservoirs
- Minimising the need for and cost of production enhancement techniques
- Access to latest technology
- Access to land
- Managing the expectations of shareholders, end-users for products, Maori groups and local communities.

Acknowledgments

The Mangahewa Gas Programme grew from the major contributions of a large number of people who participated in the Deep Gas Study and the recommendation, drilling, fracturing and testing of the Mangahewa-2 well. Those people and the current extended Mangahewa Team are thanked for their vision, their commitment and for always going the extra mile. The author thanks Fletcher Challenge Energy for encouragement and support to publish this paper.

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