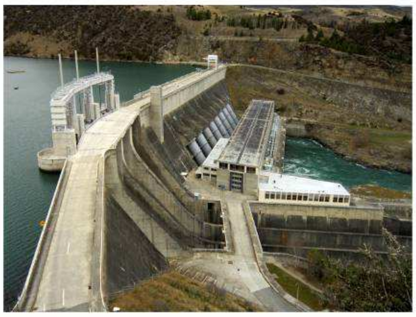
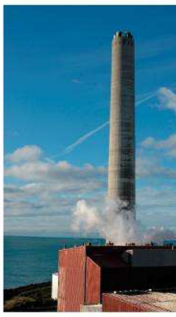
New Zealand's EnergyScape™







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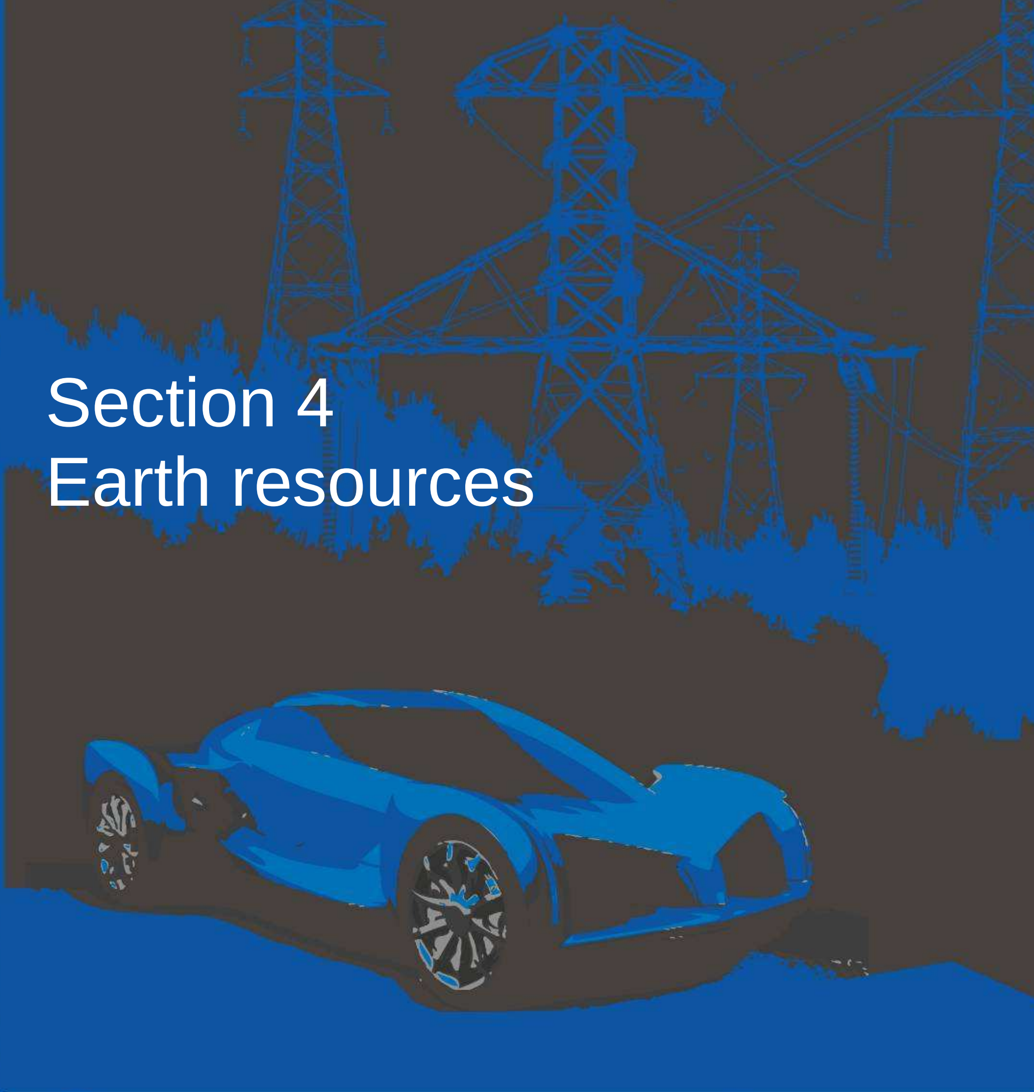
EnergyScape™ Basis Review

July 2010

Section 4
Earth resources



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EnergyScape™ Basis Review

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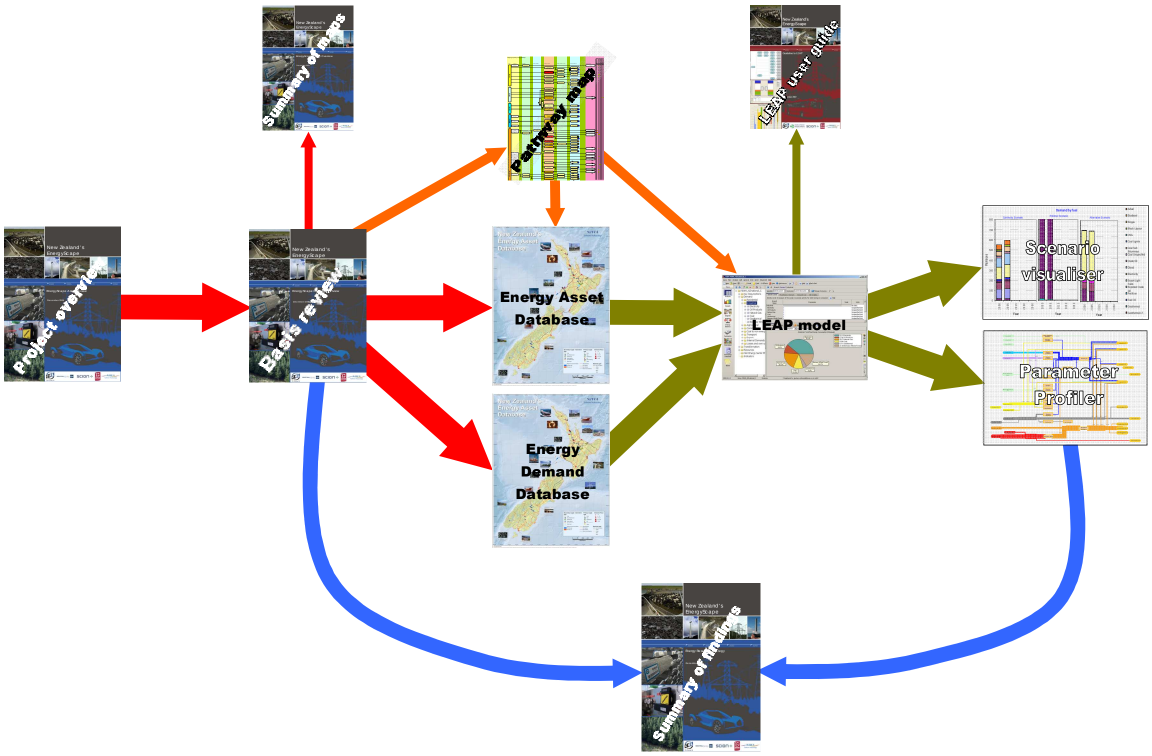
SUMMARY

The EnergyScape project is a collaborative research initiative that seeks to develop tools that can support energy policy development by considering the impact of integrated solutions for the long-term time horizon, at a regional level on a broad range of social parameters. To achieve this aim, the project has developed a series of linked tools (the EnergyScape framework) which can unify economic data, energy data, system assumptions and facilitate improved understanding of the complexities and dependencies of: resource depletion, energy substitution, transmission costs, conversion efficiencies, locality effects, scale, demand controls, environmental impact (on land, water and the atmosphere) and risk.

The linkages between some of the key deliverables of the project are illustrated below:



The “EnergyScape Project Overview” report provides the foundation for the research effort, by outlining the scope, purpose and methodology that would be utilised by the research project. The “EnergyScape Basis Review” documents the status of energy infrastructure and flows for all energy pathways in New Zealand. Data pertaining to the pathways described in the “Basis Review” were captured in an “Energy Asset Database” and an “Energy Demand Database”. These databases provide input to Long Range Energy Alternatives Planning (LEAP) models and subsequent analysis tools.

This "EnergyScape Basis Review" is intended to provide a broad introduction[1] to New Zealand's energy infrastructure. The seven (7) sections of the report cover the full spectrum of the energy system from resources, through generation, distribution, conversion and end-use:

Section 1 – Energy end-use
Section 2 – Renewable resources
Section 3 – Bioenergy resources
Section 4 – Earth resources
Section 5 – Distribution infrastructure
Section 6 – Secondary conversion
Section 7 – Hydrogen options

All energy sectors (e.g. industrial end-use, wind power, coal to liquids) are given separate chapters in the relevant section. Each chapter has been written so that if the reader only has interest for one particular area, an appreciation for how that area contributes to New Zealand's energy portfolio, now and in future can be gained by reading that section in isolation. In addition to describing the current status of public domain knowledge pertaining to energy resources, each chapter also deals with the efficiencies, risks and research applicable to this energy sector. These chapters provide the philosophy for populating the New Zealand energy asset and end-use databases.

Section 4 reviews the latest efforts to quantify our earth resources, and the technologies that support them. The development of these resources is highly dependent upon the national acceptance of risks and opportunities. In the past, New Zealand's economy has prospered from developing exports based on the large Maui gas, oil and condensate field. This section encourages policy makers to recognise the opportunities associated with developing more energy export opportunities, rather than being content to achieve security of supply. Each resource sub-section concludes with detail pertaining to the assumptions used to add resource data to the framework. Significant conclusions drawn from this section include:

New Zealand's energy endowment is sufficient to consider encouraging export opportunities as well as ensuring security of supply.

- Currently recognised geothermal resources have the potential to provide an additional ~1,500 MW of electricity using conventional technology.
- Although some geothermal waste streams must be returned to the reservoir, there is substantial opportunity to recover both low and high grade heat, for industrial and domestic applications, from these currently under utilised resources.
- New Zealand's gas endowment has provided the basis for an economic boom and development of a highly skilled industry. By world standards, New Zealand is still under explored (based on historic discovery rate and underlying geologic formation), and prospects for future natural gas (and oil) potential are promising. The opportunities to utilise any future discovery are highly dependent upon the scale and location of a discovery.
- Recent surveys scanning for methane hydrates have supported speculation that New Zealand has prime methane hydrate resources, with potential reserves an order of

[1] Capable of being read by the interested public i.e. those with some familiarity with energy system concepts.

magnitude greater than the Maui field. The immaturity of methane hydrate extraction technology leaves this opportunity as promising but speculative.

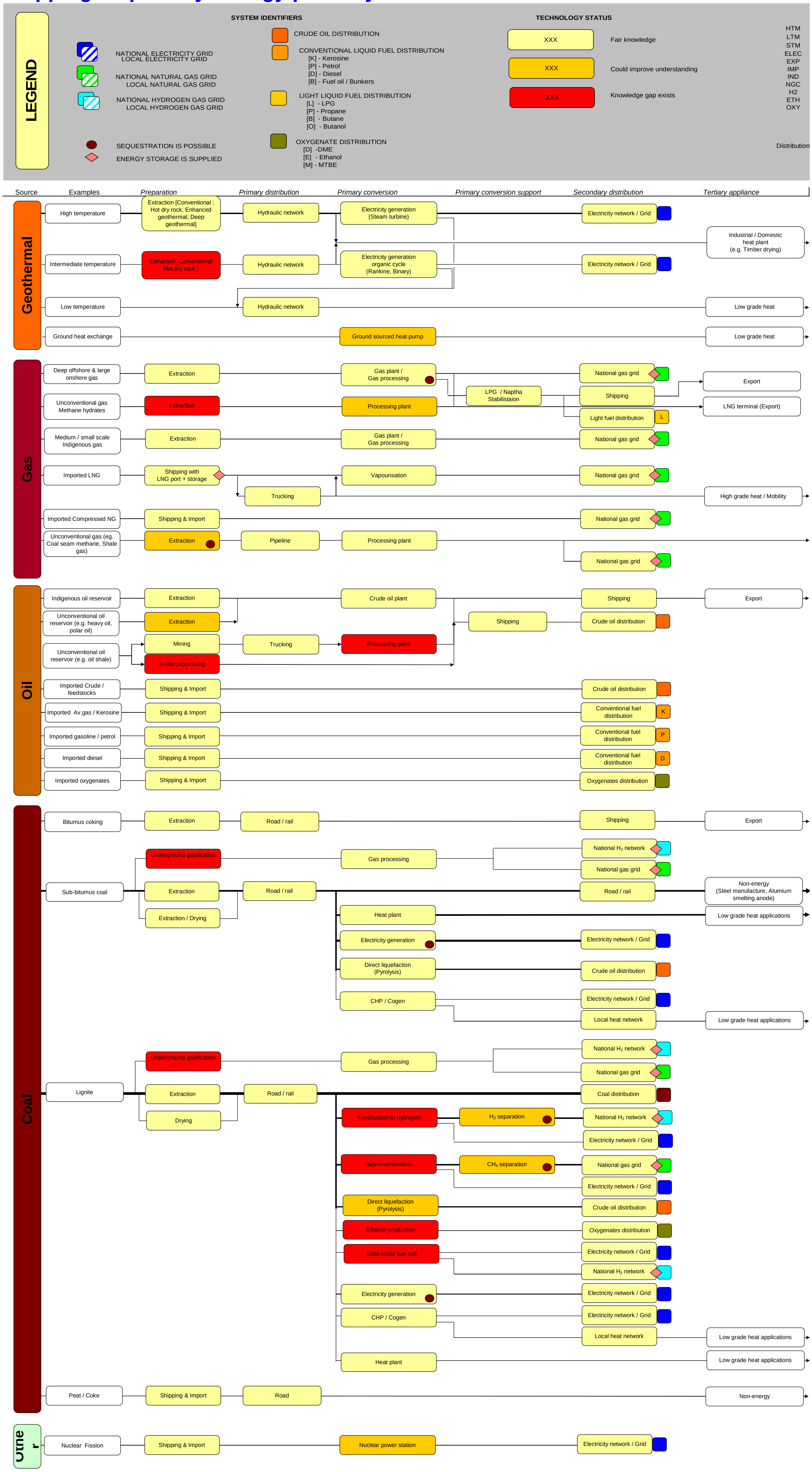
- The recent development of the Tui and Maari fields has dramatically reversed the national trend towards increased dependence on the international oil market. Unfortunately this reserve is only likely to temporarily (<5 years) offset the national need for petroleum net imports. Technological advances (e.g. deep water oil extraction) in the last few decades have opened up many more difficult to produce oil resources for commercial exploitation. Development of difficult and unconventional petroleum resources in New Zealand is however likely to be impeded by international competition for drilling rigs, capital and supporting resources.

Given the proven discoveries ... and encouraging geological similarities with Bass Strait in Australia, it is difficult to believe that significant extra deposits will not be located

- Uncertainty in the future oil price represents a significant risk to New Zealand's economy.
- New Zealand has large coal resources on a per capita basis. Increased use of this resource is currently being regulated due to concern with associated greenhouse gas impact. Gasification and carbon sequestration technologies may reduce the carbon intensity of this fuel to a level that is acceptable. Considering that this is New Zealand's cheapest fuel on an energy yield basis, there is certainly incentive to advance these technologies.

Section 4
Earth resources

Mapping of 'primary' energy pathways



4. EARTH RESOURCES

New Zealand holds the enviable position of being in control of its own indigenous coal, oil and gas reserves (both conventional and unconventional), and has significant geothermal resources. Because of the tectonic plate activity (subduction) occurring at relatively shallow depths below New Zealand's land mass, there is an abundant resource of geothermal energy within easy reach. Early indigenous settlers took advantage of the heat and hot water resources that were expressed at the surface of rock formations in the Taupo area, and this resource has featured prominently in the country's history ever since. Substantial government effort saw this resource industrialised from the 1950s onwards, playing an important role in generating electricity for the early national electricity network, and supplying heat to one of New Zealand's largest industrial sites at Kawerau. Heat and electricity from this resource still play a major role in the country's primary industry activities.

To date, significant oil and gas (O&G) activity in New Zealand has been restricted to Taranaki and, hence, the province is an obvious source of local data for the EnergyScape project. After 30 years of development and the installation of billions of dollars of infrastructure, onshore and near-shore Taranaki is now a mature oil province, with a highly skilled oil and gas service industry. All other regions of New Zealand have barely been explored for oil and gas, particularly offshore. Given New Zealand's geological history it is therefore likely that further large and small scale finds of oil and gas will be made, and even within the Taranaki region further prolific finds are possible. New Zealand also has a great future potential for unconventional oil and gas resources, in particular methane hydrates and coal bed methane. Technology for utilising these unconventional resources is developing swiftly around the world, and these developments hold great promise for New Zealand.

On a per capita basis New Zealand has a large endowment of coal, in both the North and the South Island. New Zealand coals are generally of low rank, but high grade coking (steel) coal is mined on the West Coast. Comparatively little (cf. international use) coal is used in New Zealand for electricity generation and industrial applications. This is largely a legacy of New Zealand's outstanding alternative electricity generation sources – hydro, geothermal and wind as well as the previously plentiful and cheap supply of Maui gas. Coals of higher rank are increasingly considered as a valuable export commodity. By far the largest proportion of coal in New Zealand is lignite coal in the lower part of the South Island. This low grade brown coal has received renewed attention over the last few years as a potential feedstock for the manufacture of transport fuels or basic chemicals like methanol. The utilisation of all grades of coal, but lignites in particular, leads to the emission of large quantities of greenhouse emissions for each unit of energy delivered. Expansion of coal utilisation is therefore controversial, and may incur substantial costs under a carbon tax or emission trading scheme.

The development of nuclear electricity generation facilities is controversial, not only in New Zealand but also around the world. Opposition to military and civil nuclear technology has a long history in New Zealand and has to be considered as part of New Zealand's identity and selfconception. Considering that New Zealand has no viable nuclear fuel resources, nor regions suitable for the safe disposal of nuclear waste, this technology is not a natural fit.

Integrating relatively large scale nuclear generation units into our existing electricity system would be difficult, requiring the availability of a sizable spinning reserve. Furthermore earthquake proofing a nuclear facility would add additional cost to the already substantial capital investments required, while government would be required to carry indemnity insurance cover for such a facility. This further confirms that New Zealand is neither technically nor economically well positioned for adopting nuclear electricity generation. Considering New Zealand's renewable and fossil alternatives, the development of nuclear energy in this country can be considered very unlikely.

How we used to obtain coal!

Source: Te Ara Encyclopedia.

Section 4.1
Geothermal

4.1 GEOTHERMAL RESOURCES

4.1.1 General introduction

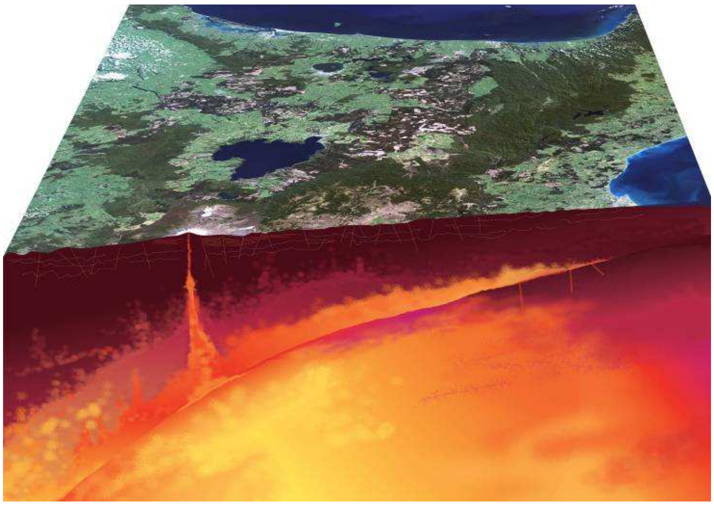
New Zealand is located along the "ring of fire", a chain of subduction zones and associated volcanoes at the margins of the Pacific Ocean, and generally has a high rate of sub-surface ground-temperature increase – that is, a steep thermal gradient leading towards the hot and molten rocks at the base of the Earth's crust. This can be increased by hydrothermal convection cells which naturally draw heat from depth through buoyancy forces and recirculation. For instance, parts of the Taupo Volcanic Zone (TVZ) have gradients of over 250°C/km, whilst the world's average gradient is 30°C/km.

Geothermal resources can be characterised by:

- 16.1 PJ/y annual electricity generation
- 9.6 PJ/y annual direct heat use
- Enormous potential for deeper-mined resources
- Immaturity in the existing drilling and resource-extraction technologies
- Significant potential for future renewable electricity and heat generation

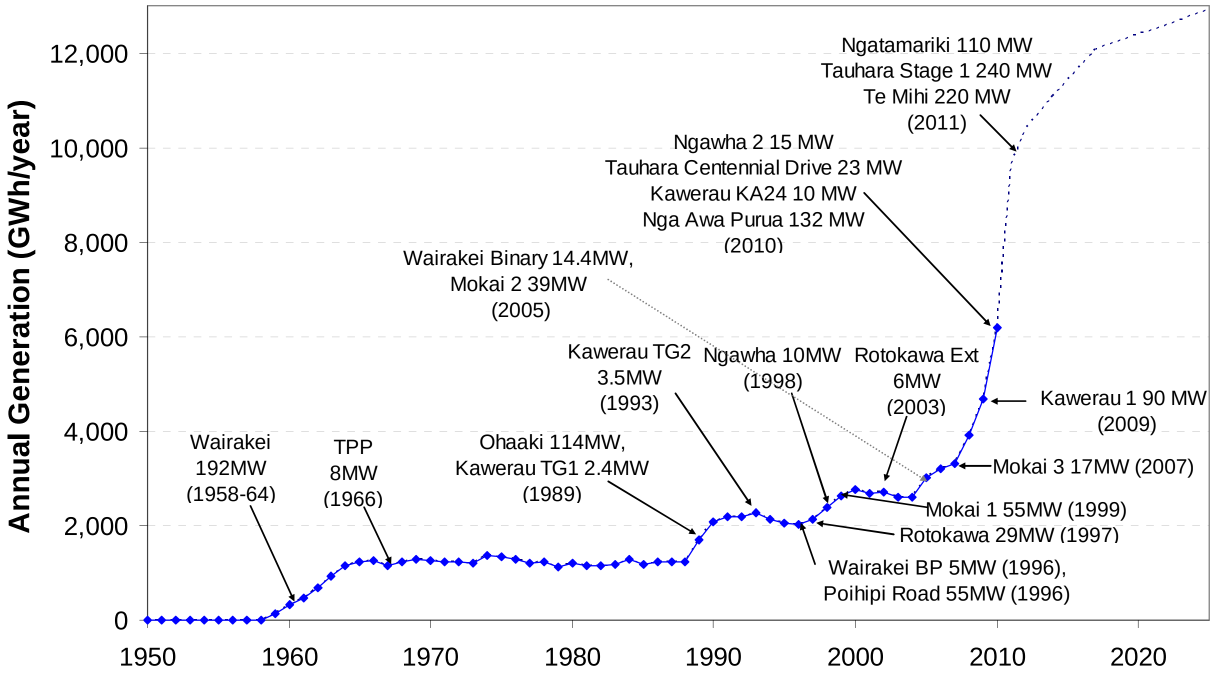
New Zealand was the first country in the world to exploit water-dominated, high-temperature geothermal systems for large scale electricity generation and for industrial-scale direct use applications. Between the 1950s and 1980s, the government invested heavily in identifying and developing New Zealand's high-temperature resources. Up to the present, developments included drilling over 500 wells in 18 fields and construction of over 700 megawatts (MW) of electricity generation, and a significant geothermal industrial supply at Kawerau. Geothermal generation was initiated in 1958 and continues to be an important component of New Zealand's energy mix. After the discovery of the Maui gas field, geothermal electricity development stalled, since it was considered more risky than thermal electricity generation based on gas, although combined direct use continued/s to experience steady growth, especially in high temperature fields.

Figure 4.1.1: Cross-section showing the Pacific Plate under the North Island and generation of molten rock rising to feed volcanoes.



Geothermal energy is renewable, requires no external fuel and, because it is not dependent on climatic factors, can play an important role in providing a secure supply of energy. Currently, geothermal energy provides 113.3 PJ (17.2%) of primary energy and 24.4 PJ (4.89%) of consumer energy, annually. Direct use of geothermal heat (largely at Kawerau for the preheating of steam in the paper mill) uses some 5.2 PJ/year.

Figure 4.1.2 – Geothermal generation uptake in New Zealand



Source: Adapted from Harvey et. al.(2010)

Interest in geothermal electricity generation was renewed during the 1990s. This was stimulated by:

- Interest by electricity supply companies in investing in medium scale generation projects.
- Persistent marketing efforts by Ormat - a manufacturer of binary cycle technology.
- Increased demand and concern over Maui depletion.

There was further and ongoing stimulation from around 2003 due to:

- The recognition that remaining gas reserves in the Maui gas field were low, and gas prices rose.
- Increase in coal prices.
- Uncertainties in hydro capacity, due to occasional dry years (associated with El Nino weather patterns).
- The requirements to reduce CO_2 emissions to meet Kyoto commitments.

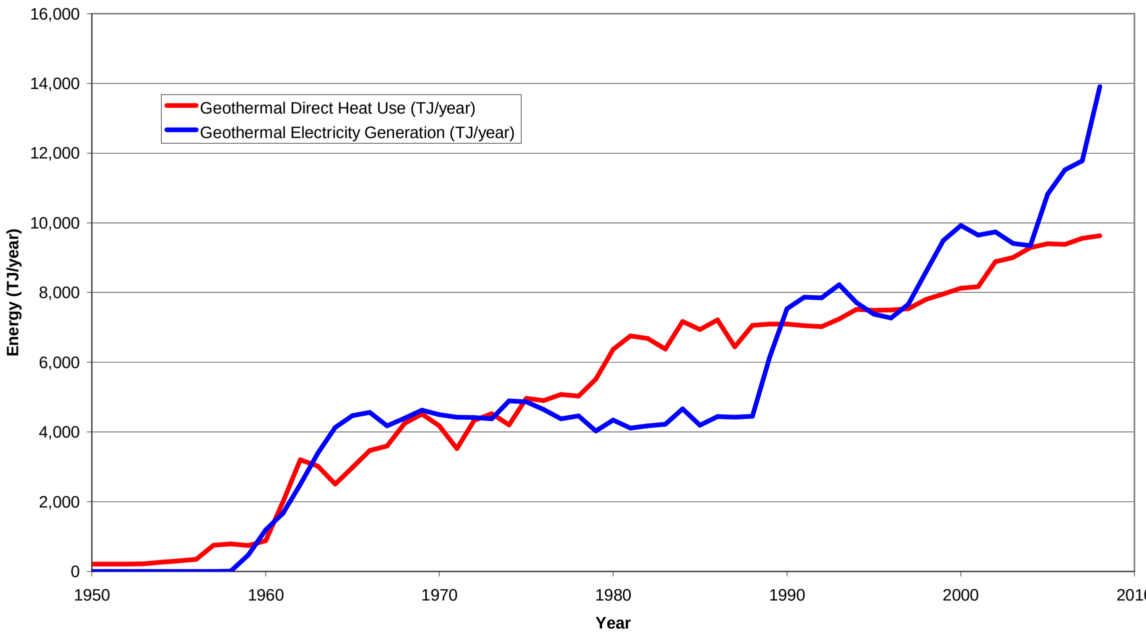
With geothermal generation now recognised as a significant, but under-developed, renewable resource, the 2008 Statement of Opportunities (Electricity Commission, 2008) identified that planned installations of geothermal plants will raise the current electrical generation capacity from just over 700 MW to 1,120 MW by 2016. The New Zealand Geothermal Association further predicted that it should be possible to generate 1,500 MW of electricity from known consentable geothermal fields [Harvey (2007), White (2007)].

Direct use of geothermal resources is receiving increasing attention because:

- Geothermal heat is cost effective with other fuels when heat demand has sufficient scale and is local to the resource.
- Direct use of so called waste-heat from high-temperature geothermal electricity plants can be utilised in a cascaded range of applications if silica deposition is controlled (Figure 4.1.14).
- Direct use of lower-temperature resources for greenhouses, domestic heating and bathing etc is now an established use, and there is growing awareness of the opportunities.

In practice, there has been fairly steady growth of direct heat use over the last 50 years in New Zealand, with the following graph showing that this use is of a similar order to electricity generation (until recently). There is opportunity for further expansion of direct heat use outside traditionally considered geothermal areas when the natural thermal gradient present in any part of the country is taken into account.

Figure 4.1.3 – Growth of direct heat use compared with electricity generation



Source: White (2009)

Ultimately the use of ground-source heat pump systems falls under the category of geothermal energy. The potential for this technology is large and 'clean', as it enhances the use of 'clean' electricity. These take advantage of any resource (water or soil) with thermal inertia such that the temperature is not subject to the same extremes as air. All towns or cities are located by the ocean, rivers or above ground water aquifers which can be used as an energy source and sink. For example, an estimated 275,000 residents in Sweden (population 9 million) use ground-source heat pumps for space-heating. The energy acquired in this manner equates to 7,900 GWh (28.4 PJ/year). There are also over 600 large-scale operations for factories and apartment buildings which account for 2,100 GWh/y (7.5 PJ/year) [Lund (2005)]. White et al. (2008) provides a New Zealand perspective of ground-source heat pump opportunities.

4.1.1.1 Pathways

The use of geothermal heat ranges from traditional (Māori) direct-use applications, such as cooking, heating and bathing, to high-value industrial heat and electricity generation. Some specific uses include:

- Electricity generation
- Heat for industrial processes
- Low grade heat for
  - Domestic and commercial hot water and space heating .
  - Domestic and commercial thermal pool heating.
  - Prawn farming and glasshouse heating.
- Tourism - Recreational and scenic attractions

Using high-temperature geothermal resources for electricity generation is a commercially attractive proposition. On a world scale, New Zealand ranks in the top ten geothermal electricity producers [Geothermal Resources Council (2005)]. Currently, electricity generation from geothermal has an installed capacity of just over 700 MW.

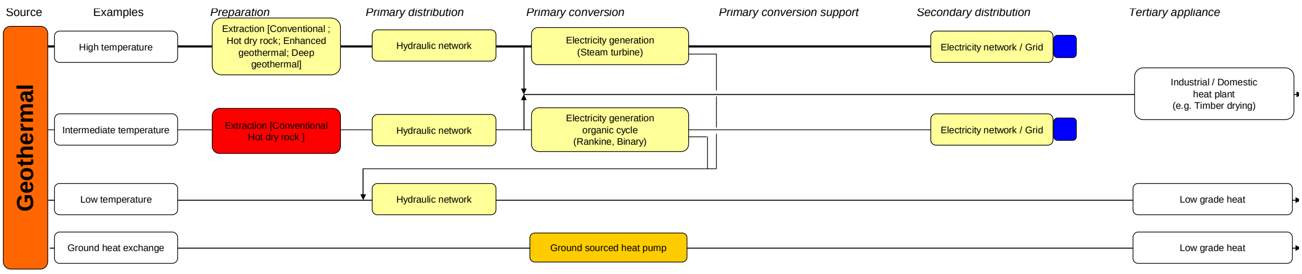
When the Wairakei geothermal system was developed in the 1950s, all waste geothermal fluid was discharged directly into the Waikato River with no reinjection. As a result, the fluid features in the Wairakei Thermal Valley failed within a few years, while at the same time there was an expansion of the steam features at Karapiti - Craters of the Moon.

Although technology and best practice have moved on, features are still altered. It is important to remember the adverse effects of geothermal development, at a time when there is more pressure to develop at the expense of features.

The direct use of surface geothermal resources has grown during the 20th Century for bathing, tourism and small-scale heating projects. Industrial-scale direct use at Kawerau is the primary application of geothermal energy at Kawerau, with waste heat being used for electricity generation. At the same time geothermal waste heat utilisation from electricity generation has been used in a small way for process heat for timber processing, pool heating, greenhouse heating and aquaculture. Direct geothermal heating and geothermal waste heat utilisation both have large scope for further expansion.

Utilisation of geothermal resources can adversely affect nearby surface features, such as geysers and hot pools. It is, therefore, necessary to balance competing interests, and manage the resource sustainably. Environment Waikato has recently developed the geothermal sections of its Waikato Regional Policy Statement and Waikato Regional Plan [Waikato Regional Council (2008)], a leading, and internationally praised set of policy documents regulating the sustainable management of geothermal resources and competing interests.

Figure 4.1.4 - Geothermal energy pathways



A full view of the pathway is presented in the Pathway Overview Map at the start of this document.

The utilisation pathway is strongly affected by the quality of the geothermal resource, which can be characterised by one of the following three categories:

1. High-temperature geothermal resources, suitable for conventional electricity generation, direct use (industrial steam) and cascade applications.
2. Intermediate-temperature geothermal resources, suitable for binary (Organic Rankine or Kalina cycle) electricity generation and direct use (some industrial processes, greenhouses, bathing, domestic heating).
3. Low-temperature geothermal resources suitable for greenhouses, bathing, domestic heating as well as domestic-scale ground-source heat pumps.

The pathways described in Figure 4.1.4 show six different geothermal extraction systems, three types of electricity generation and various direct use options. The six extraction systems are:

4. Conventional (hydraulic pressure) extraction
5. Hot, dry rock extraction
6. Deep geothermal extraction
7. Enhanced geothermal extraction
8. Surface geothermal
9. Ground heat exchange

The main electricity generation technologies and direct use systems will be discussed in the technologies section below.

4.1.1.2 Myth busting

Several myths have adversely impacted the development of geothermal assets in New Zealand. These beliefs include:

- Geothermal developments inevitably result in subsidence and loss of surface features.
- Geothermal energy will only ever provide a small fraction of space heating requirements.
- Geothermal electricity generation cannot be sustained over many years.
- Geothermal is a mature technology.
- Geothermal generation is emissions free.

These issues are considered below.

The early exploitation of New Zealand geothermal systems resulted in some surface subsidence close to the wells, and loss of several significant geysers and hot springs, due to pressure decrease in shallow aquifers (at 300 – 500 m depth). The subsidence under Taupo town was believed to be caused by extraction. Although the subsidence here is much lower than the more than 15 metres experienced in parts of Wairakei, the infrastructure such as houses and roads is much denser and more prone to damage from subsidence. Extraction at Ohaaki has also led to the loss of several highly-valued geothermal springs including the renowned Ohaaki Ngawha, and subsidence that has led to inundation of low-lying farmland, wetlands, and infrastructure such as roads. The geysers of Rotorua were depleted in their activity by multiple small domestic users of geothermal fluids, and since pressures have been restored as a result of government intervention and well closures, only some of the geysers have recovered so far. Subsequent designs of geothermal electricity plants exploit resources from much greater depths (deeper than 2 km in many cases), and / or re-inject much of the used fluids to maintain reservoir pressures. These system changes result in far less impact on surface features and considerably reduce any risk of subsidence.

The fact that geothermal energy has only ever played a minor role in space heating in New Zealand is primarily attributed to the historically very low cost of electricity in this country. It is likely that this situation will change as new technologies (e.g. ground-source heat pumps) become more available (as demonstrated in other countries e.g. Sweden) and the cost of fossil fuels and electricity increases.

For many years, it was considered that the long-term use of a geothermal resource would ultimately result in rapid depletion of the resource. Wairakei electricity station has now been operating for over 50 years and still has a similar (in fact higher) level of output as at the time it was commissioned. This was achieved through a combination of careful resource management, higher-efficiency steam separation, along with deeper drilling and condensate reinjection. It is very difficult to predict the decline rates of individual geothermal fields, as they depend on a great number of factors that vary greatly from field to field, however with controlled rates of extraction the resource can be used for many human lifespans.

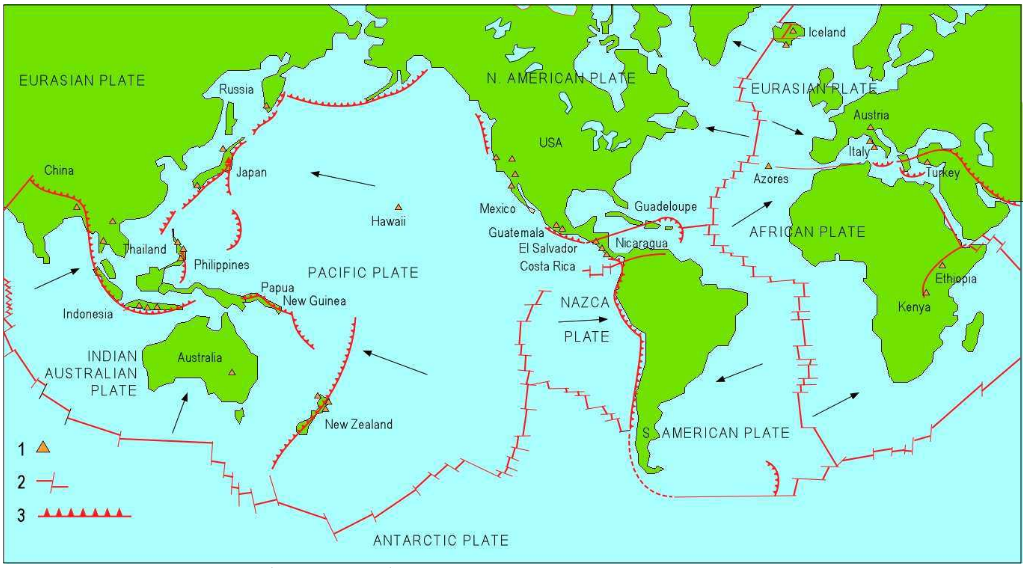
New Zealanders have been familiar with geothermal developments for half a century now and many think that geothermal technology is mature. This is not the case - current exploitation of geothermal resources in New Zealand is limited to less than 3 km depth, while temperatures continue to increase with increasing depth, which increases resource potential and efficiency. Research on deep geothermal resources, applications and the environmental issues is needed in order to expand geothermal electricity generation in New Zealand. For example, the development of new binary (Organic Rankine and Kalina cycle) technologies for lower temperature generation over recent years are enabling us to better utilise our existing resources.

It needs to be remarked that geothermal electricity generation may result in carbon dioxide emissions into the atmosphere and discharge of minerals from the aquifers into surface waters. The extent of emissions and discharges depends on the aquifers, the environmental regulations in place and the technologies applied. Carbon dioxide emissions are reservoir dependent – emissions from some fields (e.g. Ngawha) are high, whilst many fields (e.g. Wairakei) are low. In general, modern production and generation technologies incorporating reinjection, means that geothermal electricity generation has lower greenhouse gas (GHG) emissions than thermal generation.

4.1.2 Introduction to the resource

New Zealand is recognised for the quality of its geothermal endowment (see Figure 4.1.5). The Taupo Volcanic Zone (TVZ) is particularly well recognised, with more than 20 active hydrothermal systems.

Figure 4.1.5: World pattern of plates, oceanic ridges, oceanic trenches, subduction zones, and geothermal fields



LEGEND: Arrows show the direction of movement of the plates towards the subduction zones.

(1) Geothermal fields producing electricity
(2) Mid-oceanic ridges crossed by transform faults (long transversal fractures)
(3) Subduction zones, where the subducting plate bends downwards and melts in the asthenosphere

Source: International Geothermal Association

Geothermal fields are commonly located from geophysical surveys. Field capacities are determined by drilling and flow-testing.

The three levels of geothermal resources considered here are:

- High-temperature resources suitable for cost-effective electricity generation or for industrial heat supply. Traditionally, this has included resources with reservoir temperatures above 200 °C.
- Intermediate-temperature resources with temperatures less than 200 °C, but above 100 °C, suitable for electricity generation using binary technologies and for industrial and domestic heat supply.
- Low-temperature resources with reservoir temperatures below 100° for direct use and, only very rarely, used for electricity generation. With the ever-increasing costs of fossil fuels however, their use for electricity generation may increase.

High-temperature fields can be further divided into two types: dry-steam fields and water-dominated fields. All high-temperature geothermal fields developed in New Zealand are water-dominated, but, in places, steam zones have developed which have the potential to provide steam at relatively shallow depths.

Extraction of steam from dry-steam fields simply involves drilling wells into the resource and passing the steam through a turbine. For water-dominated fields, a reduced pressure flash is used to maximise steam yield prior to separating the water from the steam and then passing the steam through a turbine. The waste-water from the separator can either be utilised for further electricity generation or a range of direct uses. Alternatively, it may be re-injected into the reservoir or discharged to the environment.

Conventional steam-turbines operate most efficiently at higher temperatures and pressures than usually provided by geothermal resources. Many resources are below the threshold temperature for conventional steam-turbine electricity generation. More recent improvements in turbine design have enabled lower pressures (and lower temperatures) to be used with relatively good efficiencies.

4.1.2.1 High-temperature resources

High-temperature resources are classified as those having reservoir resource temperatures of greater than 200°C[2]. The most complete estimates of high-temperature resources considered by Lawless (2002) and SKM (2002) is provided in Table 4.1.6. The method for estimating the electricity potential involved:

- Assuming 30 year field life.
- Defining the boundaries of the exploitable resource area, based on geophysical surveys (i.e. resistivity maps) and / or borehole data around discovered fields.
- Estimating the resource thickness and a range of resource temperatures, based on drill-hole information and account for recent (>340°C) borehole information.
- Undertaking stored heat calculations using porosity and heat recovery factors, based on the understood geology, assuming a lower exploitable temperature limit of 180°C.
- Steam turbine efficiencies based on 2002 technologies.

Table 4.1.6 - Potential New Zealand geothermal generation

Field	Resource area (km²)			Depth to reservoir (m)	Mean temperature (℃) [4]			Electrical generating capacity (MW)		
	Min	mode	max		Min	mode	Max	10TH	median	90TH
Atiamuri	0	0	5	800	190	220	240	1	6	18
Horohoro	0	0	5	500	180	200	240	1	5	15
Kawerau	25	35	40	400	260	270	280	350	450	570
Ketetahi	10	12	30	800	230	240	260	70	100	150
Mangakino	0	8	10	800	200	230	250	20	47	70
Mokai	5	6	16	700	260	280	290	95	140	220
Ngatamariki	8	10	12	400	250	260	270	90	120	160
Ngawha	10	18	25	400	220	240	260	50	75	120
Ohaaki	6	10	12	400	260	270	280	100	130	170
Orakei-Korako	8	10	12	400	240	250	260	90	110	135
Reporoa	0	9	12	700	220	230	240	20	42	65
Rotokawa	12	18	20	500	260	280	290	230	300	400
Rotoma	4	5	6	500	220	240	245	28	35	46
Rotorua[1]	2	4	8	500	220	240	250	25	35	55
Tauhara	7	15	35	500	240	260	270	200	320	500
Te Kopia	6	10	12	500	230	240	250	75	96	120
Tikitere-Taheke[2]	15	35	40	500	220	240	260	160	240	350
Tokaanu	10	20	30	800	250	260	270	130	200	300
Waimangu	9	12	30	400	250	260	270	180	280	420
Waiotapu[3]	15	20	30	500	260	275	280	250	340	450
Wairakei	15	20	30	350	250	255	265	380	510	670
Means and totals		277		540		250		2500	3600	5000

NOTES:
1. Excludes Lake Rotorua
2. Excludes Lake Rotoiti
3. Includes Waikite
4. Mean temperature through accessible reservoir thickness and area. For developed fields, before exploitation

[2] 220°C was the optimal temperature for conventional steam-turbines in the 1950s. Now 200°C is considered optimal.

Based on experience / judgement and consideration of a 200°C lower exploitable temperature limit and modern turbine efficiency (and potential for as-yet-undiscovered resources), it is estimated that the high-temperature exploitable resource, using conventional technology, is nearly 2,800 MWe.

It may be argued that a geothermal development is only sustainable when surface features, as well as the resource at depth, are preserved. The total generating capacity that would result from this approach can be estimated by considering a 300 year field life using natural heat flow as the lower limit on extraction rate. For the Waikato region, the total “enduring” generating capacity is considered to be about 420 MWe (SKM, 2002).

4.1.2.2 Intermediate-temperature resources

Intermediate-temperature geothermal resources range from 200°C down to 100°C. These resources have, historically, been below the threshold-temperature for conventional steam-turbine electricity generation. However, with the development of binary plants, these resources can now be harnessed for electricity generation.

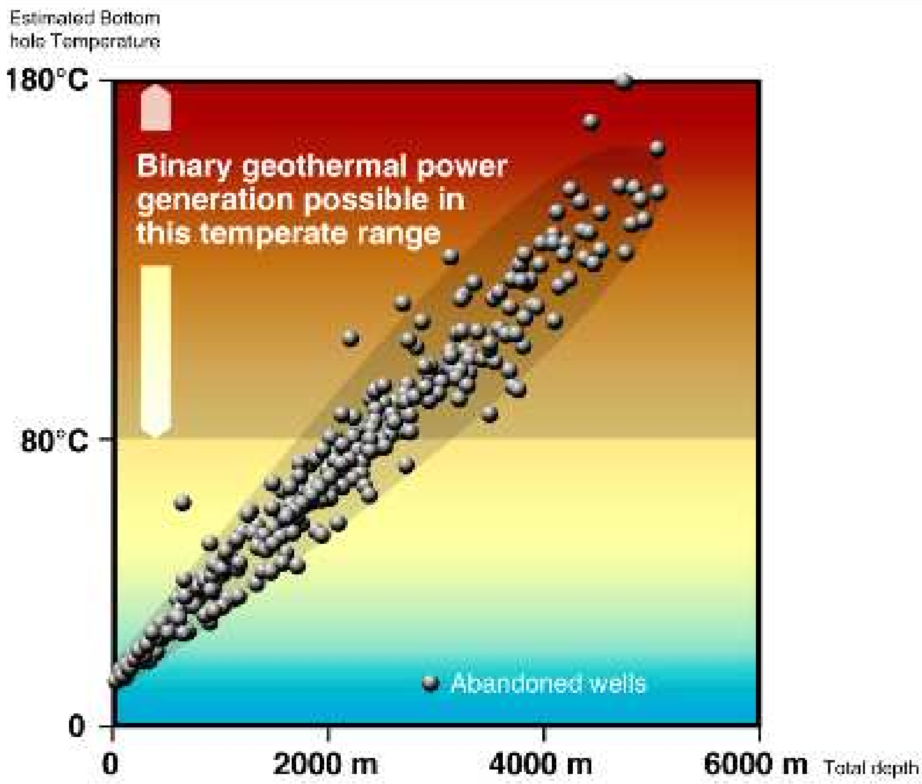
Because of the perceived value of the high-temperature resources for conventional electricity generation, these intermediate-temperature resources have received limited attention to date. Little is known of their extent or their true potential for a range of applications, which could include electricity generation and lower-temperature direct uses.

Indications of the potential resource capacity can be made, based on the observation that adding a binary plant to a conventional high-temperature plant can increase production by between 10 and 15%. Based on this, the total intermediate resource from known fields is estimated to be around 900 MW (including electricity generation for extraction from 200°C to 180°C).

Recently, GNS Science Ltd has been appraising the potential of using abandoned oil and gas wells as a source of heat exchange for intermediate-temperature steam, and have identified several abandoned wells which could be used to generated electricity - see below.

Whether the wells themselves are used or not may be of little relevance. What these wells show is that there is a natural thermal gradient of about 30^{o}C/km in the sedimentary basins drilled in New Zealand. Target temperatures for heat applications or electricity generation can be reached at known depths. Now more careful consideration is needed of the extent of these resources and the detail of the temperature gradients. Wider assessments are needed of gradients across the country, possibly by less direct methods than well drilling.

Figure 4.1.7 – Intermediate-temperature opportunities in abandoned oil and gas wells



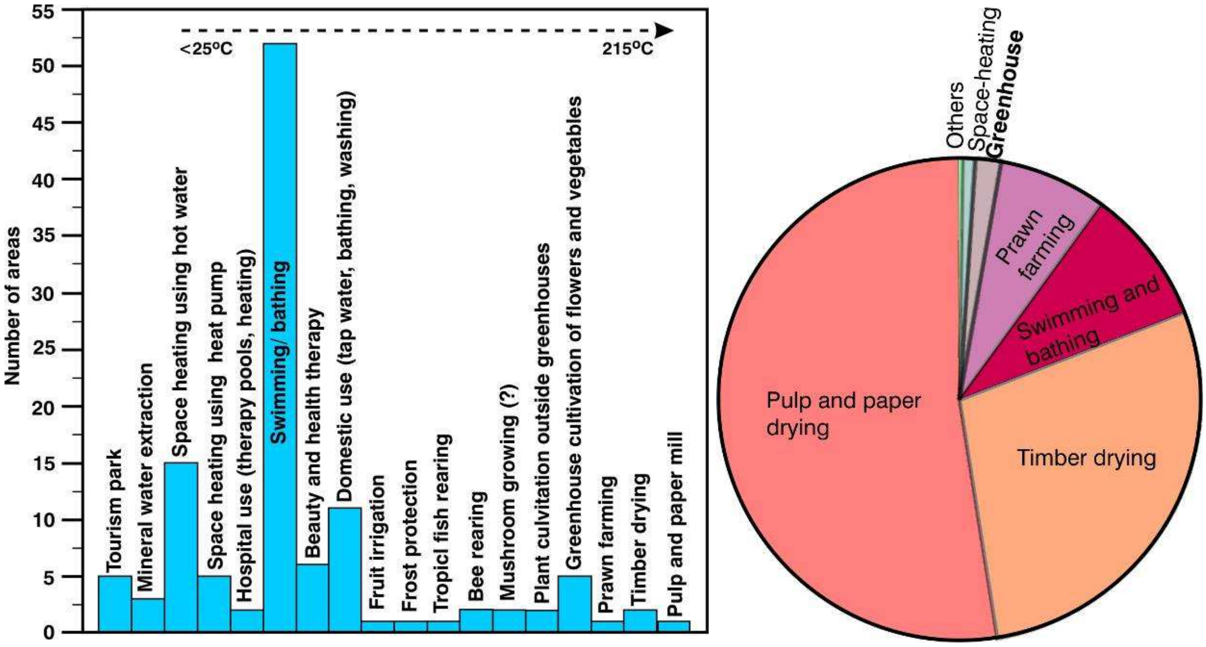
4.1.2.3 Low-temperature resources

Low-temperature geothermal resources are classified as those resources with temperatures less than 125°C. It also includes geothermal resources whose separation water temperature (also called 'waste-water') is around or below 130°C. Very little of this resource is used for electricity generation. The primary use of this resource is for direct-use applications such as water and space heating.

White (2007) estimated that proven, low-temperature resources exceed 10,000 MW, of which we currently use less than 5%. It should be noted that a significant portion of separation water from geothermal power stations is re-injected into the source reservoir so as to maintain reservoir pressures. The original 1950s development at Wairakei is an example of the waste of low-temperature resource. The original consents for this development allowed the discharge of waste geothermal fluid into the Waikato River. More recent geothermal developments have stricter environmental constraints and use a combination of mechanical draft cooling towers allowing recirculated cooled condensate to drive condenser vacuum, and re-injection of the separation water.

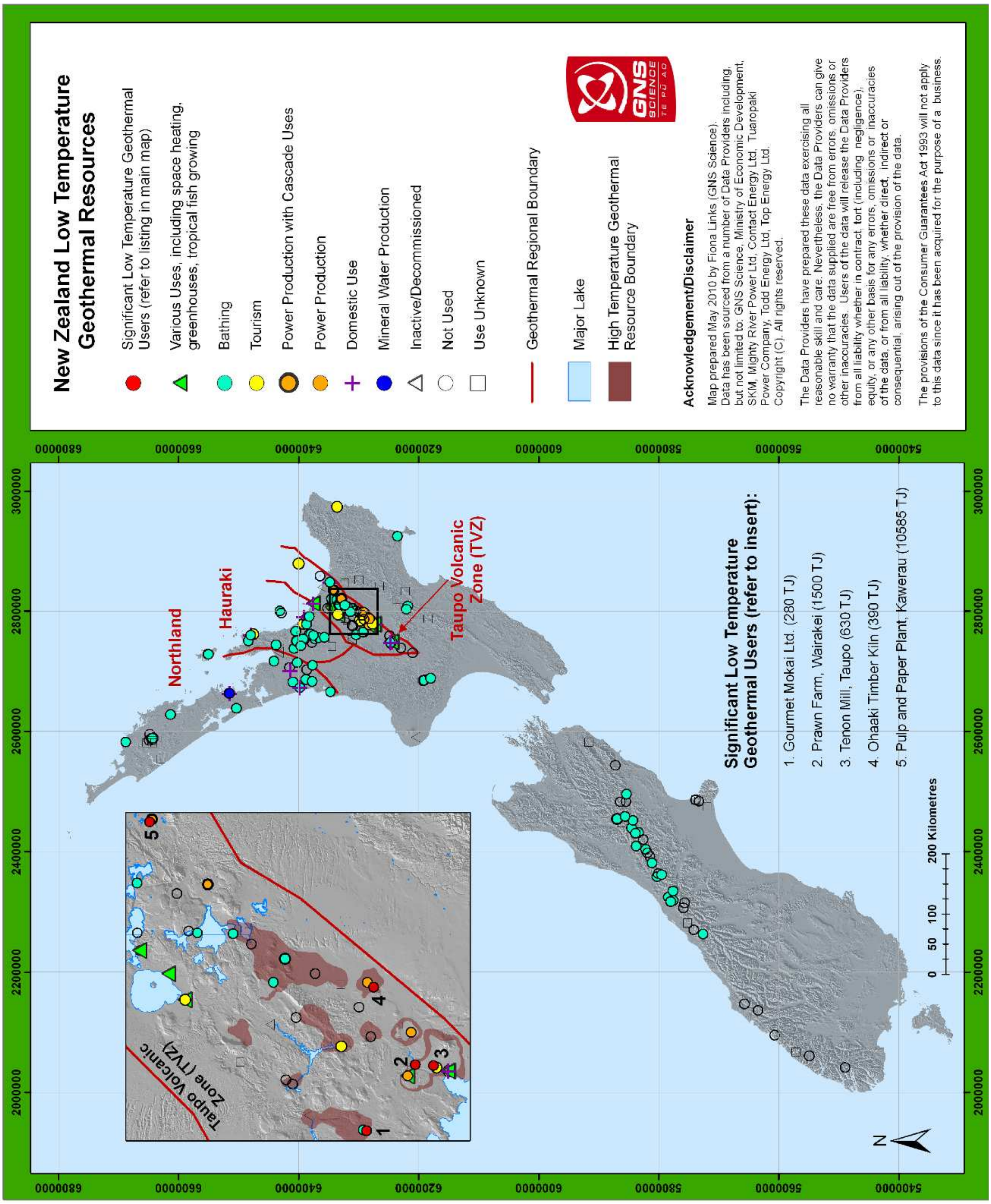
New Zealand's current use of direct geothermal heat was reviewed by NZGA (2009). This review identified that nearly 94% of direct-use occurs within the Rotorua-Taupo Geothermal Region, with 55% attributed to operations at Kawerau. The results are summarised in Figure 4.1.8 below:

Figure 4.1.8 – Direct geothermal energy use in New Zealand



Other likely locations for deriving low-temperature geothermal resources are signalled in the log of geothermal utilisation in New Zealand by Thain, Reyes, Hunt (2006). It should be noted that less than one-third of all New Zealand thermal springs and geothermal areas have undergone any development. Consequently, there is still much opportunity for harnessing of geothermal energy and also the development of ground-source geothermal heat (via home or industrial heat pumps).

Figure 4.1.9 - Log of New Zealand's geothermal resources



There is considerable potential for access to low-temperature resources with ground-source heat pump systems. Akin to solar, this is a universal resource where the utilisation is only limited by access to capital.

4.1.3 Barriers and limitations

High and intermediate temperature geothermal developments are currently some of the most promising opportunities in New Zealand; this can be attributed to:

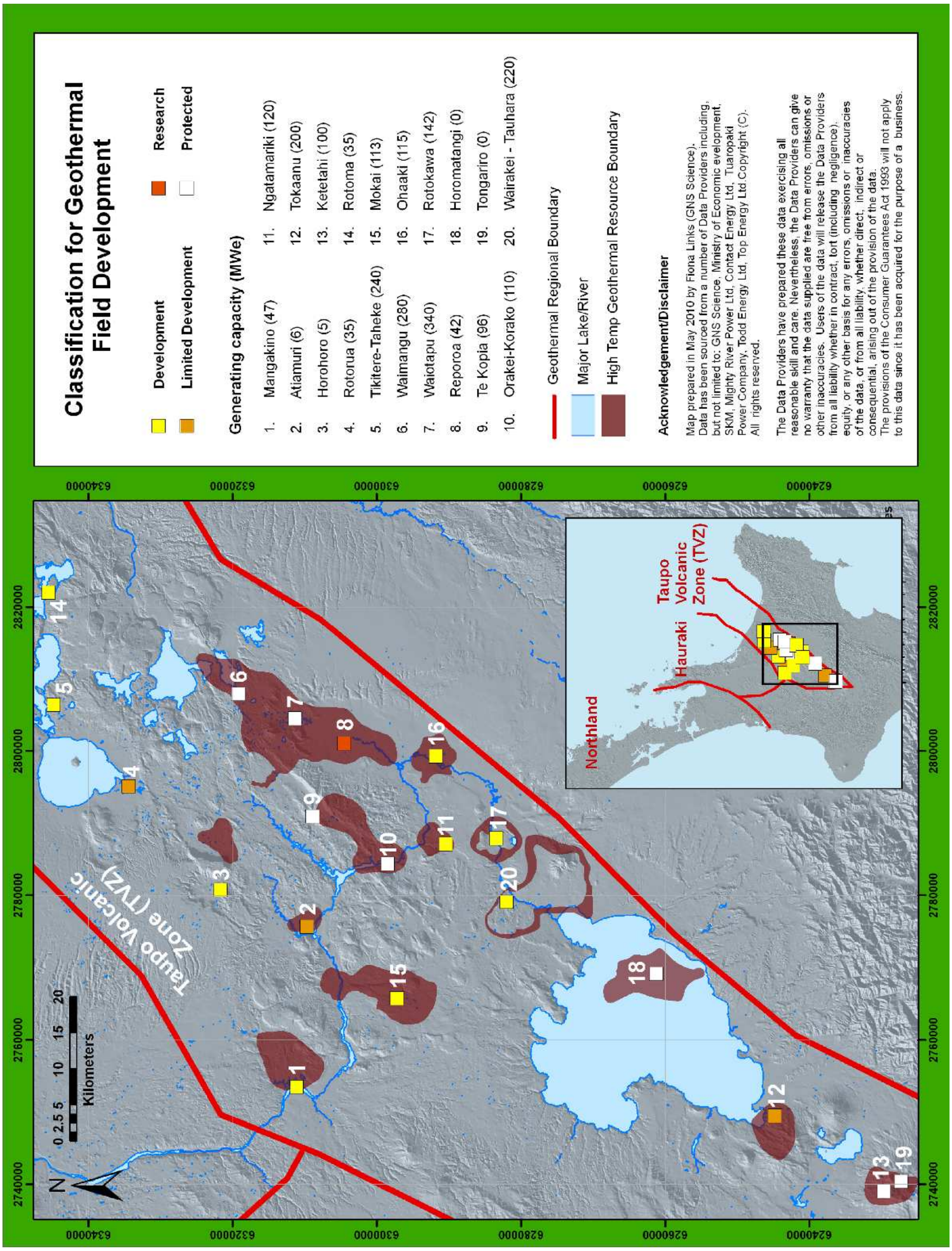
- Tightening of electricity supply market – hence higher electricity prices.
- Operating costs of thermal generation increasing – gas and coal prices increasing, and likelihood of a carbon charge being introduced.
- Increased clarity regarding development considerations pertaining to the Resource Management Act (RMA).

The early stages of geothermal resource development, such as exploration and drilling deep production wells, are considered high (financial) risk, as it is not possible to accurately predict the electricity potential of a geothermal field until the actual wells have been drilled and tested. The revenue stream from operation is however quite dependable since geothermal is predominantly used as a cheap base-load resource. For steam-dominated resources, some form of load-following may be possible, but this has seldom been adopted in New Zealand (Poihipi is the exception here). There may be an upper limit of base-load beyond which it may not be practical or cost-effective to develop further.

Because high temperature geothermal developments have the potential to modify hydraulic structures and surface features, it is appropriate to scientifically evaluate prospective impacts in the context of economic and cultural value. The Resource Management Act (RMA) supported by regional plans is the primary mechanism for managing the risks, benefits and disadvantages of geothermal resource development. Since this is a complex task with many competing interests, the mechanism can be viewed as too rigorous or time consuming by development proponents.

In order to reduce RMA hurdles and clarify which fields need protection, Environment Waikato has classified large geothermal systems as either: Development, Limited Development, Research, or Protected - as identified in Figure 4.1.10. The classification was based on the application of the precautionary principle to the management of regional geothermal resources where scientific uncertainty represents a threat of serious or irreversible effects. Understanding of field risks and development potential is expected to reduce management conflicts associated with development of these fields.

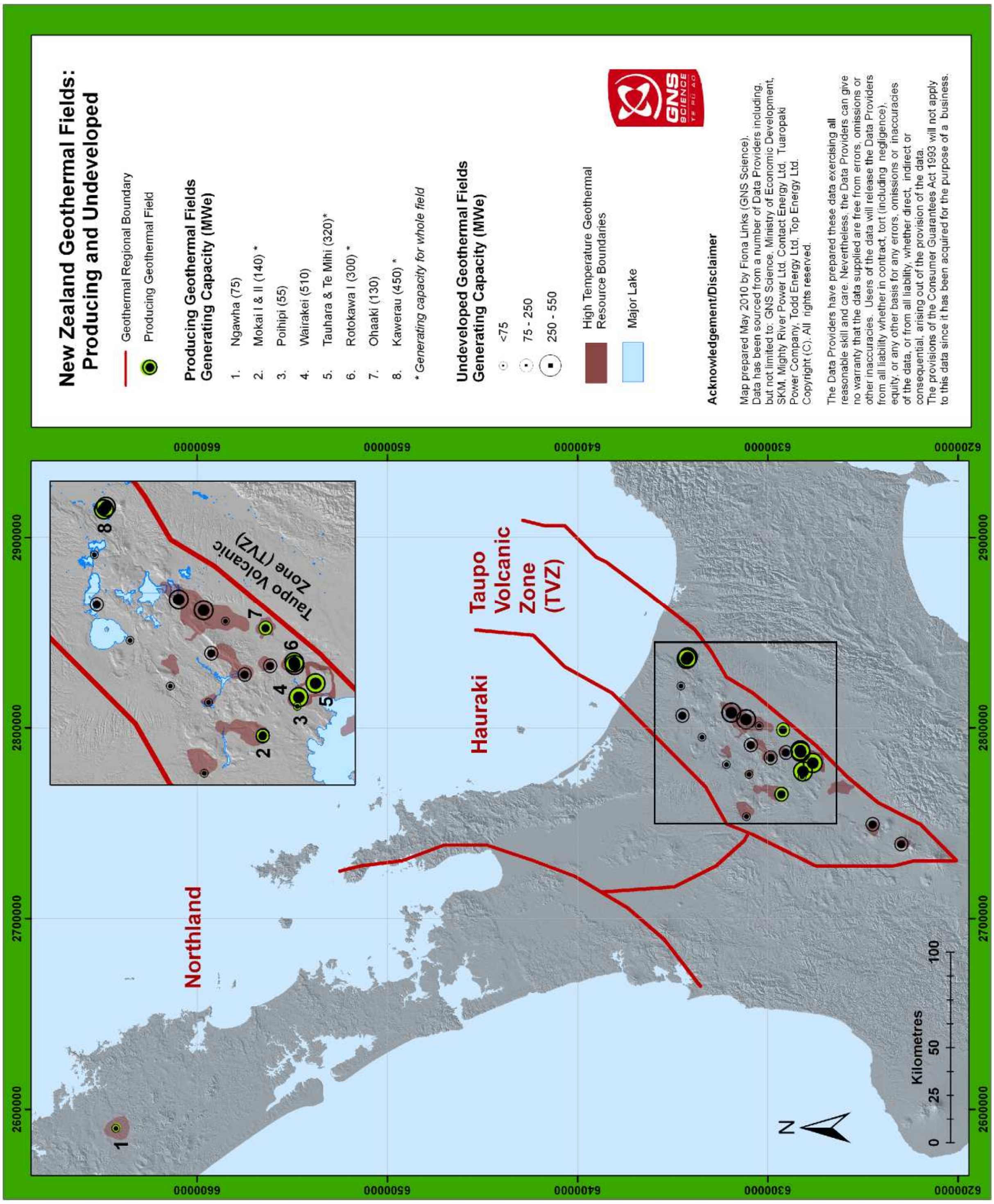
Figure 4.1.10 - Development classification of geothermal fields



Land and resource easement access rights significantly limit the number of companies that can engage in geothermal development. Virtually all easements are held by Contact Energy and Mighty River Power, whilst landowners above resources tend to compete amongst each other for meagre resource access agreements.

The potentially realisable geothermal electricity generation can be defined, based on the Lawless (2002) estimate (see Table 4.1.6), with those fields not open to development being excluded.

Figure 4.1.11 – Realisable geothermal electricity generation



Direct use of lower-temperature geothermal resources seems to only be limited by the identification of suitably located (or relocated) low grade heat demand. Growing awareness regarding the success of prawn farming, hot house production and residential heating are likely to increase the utilisation of this resource.

4.1.4 Introduction to conversion technology

For each grade of geothermal resource, different technology pathways are appropriate. Each pathway will have its own extraction systems and conversions systems.

4.1.4.1 High-temperature resource – Extraction system

Five extraction systems are relevant to high-temperature resources, namely:

1. Conventional (hydraulic pressure) extraction
2. Enhanced geothermal extraction
3. Hot dry rock extraction
4. Surface geothermal
5. Deep geothermal extraction

The status of the first four of these extraction systems were reviewed by PB Power (2007) and are shown in Table 4.1.13**.**

Figure 4.1.12 – Visualisation of the Nga Awa Purua power station

Table 4.1.13 – Status of geothermal extraction systems

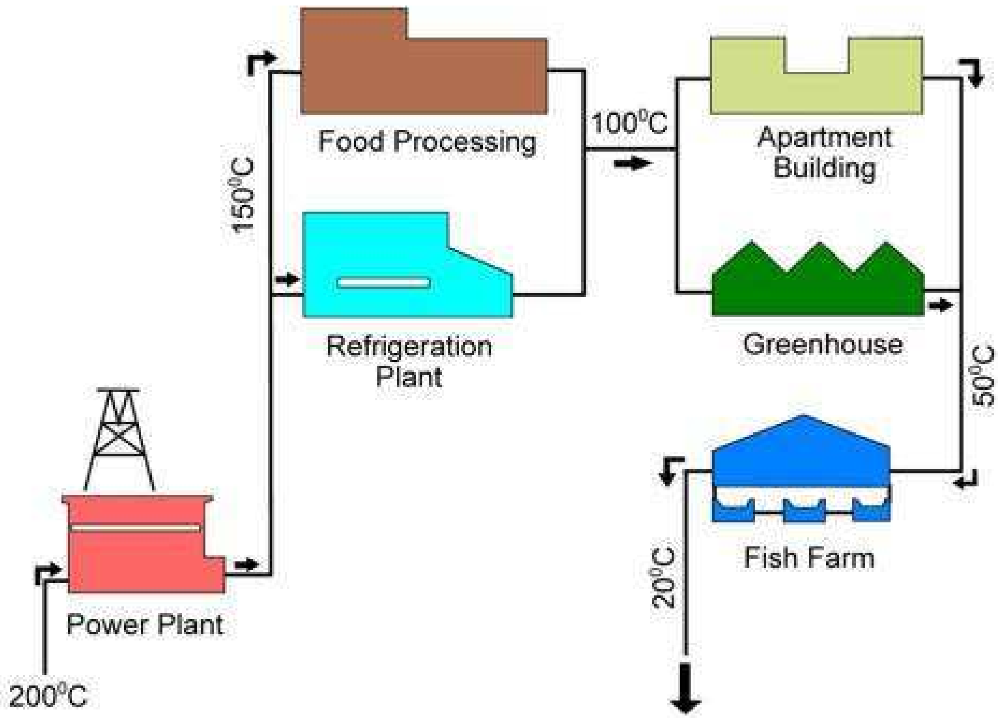
		Conventional	Enhanced	Hot dry rock	Surface
Technology maturity		High	Low High-cost of hydraulic fracturing has discouraged technology development	Low Has had long R&D time. New technologies are required for high pressure resources e.g. Australia	High
Cost data	Capital Costs	Surface equipment:1000 US$/kW for 110 MW plant to 3000 US$/kW for 5 MW Steam-field and drilling very variable and project related		Surface Equipment:1400 US$/kW for 55 MW; 2400 US$/kW for 15 MW If very high pressure (Cooper Basin) Add 15 - 20% Drilling:1.3 - 1.5 MUS$ per km (> 2 times oil and gas costs)	
	Operating & Maint.	Typical O & M costs for thermal electricity plants, with some additions for steam / brine quality monitoring and silica / NCG etc… treatment		No relevant information available	
Performance data	T > 125 °C	Conversion efficiency ranges from less than 10% (binary low-temperature) up to 17% for triple-flash and high-potential resource.		16% conversion efficiency for a 240°C resource. (Ranges from 11 - 22% between 150 - 350°C)	
Implementation	< 2 years	Steam field and electricity generation Plant engineering, construction and commissioning		Small demonstration electricity plant (like 1.5 MW Ormat at Soultz)	
	2 - 5 years	Sub soil investigations Exploratory and production drillings		Steam-field and electricity plant	
	> 5 year			Sub-soil investigations, Drilling Stimulations	
Trend in NZ	< 5 years	Continued progress with Kawerau, NAP, Wairakei projects			
	> 5 years	Mighty River Power to develop projects for more than 400 MW		NZ geology not optimum for HDR development Needs more Investigation	
Major Equipment	Suppliers	Toshiba Ansaldo Mitsubishi Fuji Ormat GE Alstom		Ormat Siemens Mitsubishi Fuji Conoco Schlumberger	

4.1.4.2 High-temperature resource – conversion system

Currently, all extracted high-temperature geothermal steam is used to generate electricity using conventional steam turbines. The outlet temperatures and pressures achieved are based on cost, efficiency and avoidance of silica deposition.

Appreciable savings can be achieved by adopting integrated systems that offer a higher utilisation factor (for example, binary cycle or combining space-heating and cooling) or cascade systems, where the plants are connected in series, each utilising the waste-water from the preceding plant. An extensive example is illustrated in Figure 4.1.14.

Figure 4.1.14 - Cascading use of geothermal resources



Source: International Geothermal Association (Italy)

The status of electricity generation systems was reviewed by PB Power (2007) and is shown in Table 4.1.15.

Table 4.1.15 – Status of electricity production systems

		Steam turbine	Organic Rankine Cycle	Kalina cycle
Technology maturity		High Triple-flash applications to develop where possible	High Standard converting modules Efficiency at low-temperature not optimized	Low Growing fast Many planned projects
Cost data	Capital Costs	Turbine /generator prices vary between 700 US$/kW (very large units of more than 100 MW) and 1200 US$/kW (small units of less than 10 MW)	ORC units range from 1500 US$/kW (temperature range 150 to 200℃) to 2500 US$/kW for low-temperature applications Combined cycle 2000 to 2750 US$/kW	2200 US$/kW to 3000 US$/kW for units ranging from 110 - 200℃
	Operating & Maint.	Typical turbine/generator O & M costs for thermal electricity plants.	From 0.4 US$c/kWh for 25 MW plant to 0.9 US$c/kWh for 5 MW unit	From 0.4 US$c/kWh for 25 MW plant to 0.9 US$c/kWh for 5 MW unit (anticipated)
Performance data	T>125 ℃	Turbine isentropic efficiencies between 0.8 and 0.85	Conversion efficiency between 7.5% (low temp. below 125 ℃) to 15% (200 ℃ or more)	Conversion efficiency increased by 20 - 40% compared to ORC for temperatures below 125℃. Efficiency up to 17% for higher temperatures.
Implementation	<2years	Engineering, manufacturing and installation of electricity train	Ormat modular units manufactured and installed in less than 12 months	Typical Kalina plant engineered and constructed in 18 months
	2to5yrs			
	>5years			
Trend in NZ	<5years	Fuji Mitsubishi to continue progress	Ngawha project in progress	No reported project
	>5years	Good perspectives with big projects of more than 100 MW in portfolio	Must adapt commercial approach in NZ, especially if competition rises	Kalina to show operation feed back in Europe and US first
Major Equipment	Suppliers	Toshiba Ansaldo Mitsubishi Fuji Ormat GE Alstom	Ormat (world leader) Turboden	Recurrent resources Siemens

NOTE: Conversion efficiencies are from extracted-thermal to generated-electrical power.

4.1.4.3 Intermediate temperature resource – extraction system

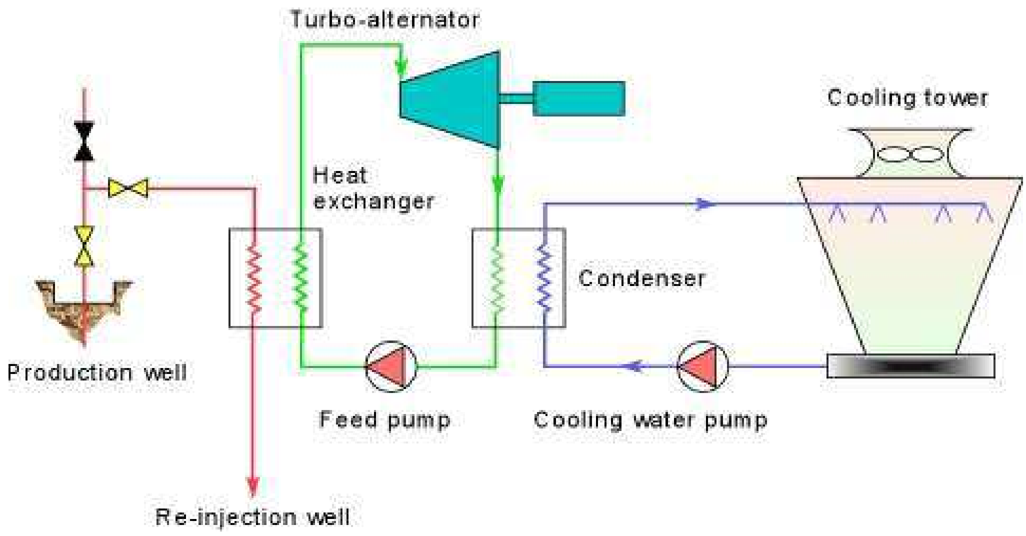
All of the extraction systems that are relevant to high-temperature resources are equally applicable to intermediate-temperature resource extraction. Since there is less energy in intermediate-temperature resources, only more innovative extraction systems are likely to be cost-effective.

4.1.4.4 Intermediate temperature resource – conversion system

In recent years, the development of binary (Organic Rankine and Kalina cycle) electricity generation systems have lowered the minimum economic extraction temperature significantly. The binary electricity plant passes geothermal water through heat exchangers to heat and vaporize a low-boiling-point organic fluid (such as pentane), which is then fed into a turbine to generate electricity (see Figure 4.1.16). Most modern geothermal power station developments use two cycles to recover energy in two stages from the incoming steam feed - especially for high temperature geothermal fields. The high-pressure steam is first fed into the steam-turbine and, upon exit as a lower-temperature water vapour, is fed into the binary unit. Lower temperature geothermal fluids can directly be fed into a binary plant. It is now possible to utilise fluids down to base temperatures as low as 100°C and, as turbine efficiencies have improved, greater utilisation of binary power plants has enabled greater utilisation of resources to lower temperatures.

Figure 4.1.16: Sketch of a geothermal binary power plant

(Flow of geothermal fluid is in red. Secondary fluid in green. Cooling water in blue)



Source: International Geothermal Association

Some direct-use geothermal applications (e.g. wood drying) are economically viable uses of intermediate-temperature resources. These are discussed below.

4.1.4.5 Low-temperature resource – extraction system

Since there is less thermodynamic potential in low-temperature resources, only simple, cost-effective extraction systems are appropriate. These are:

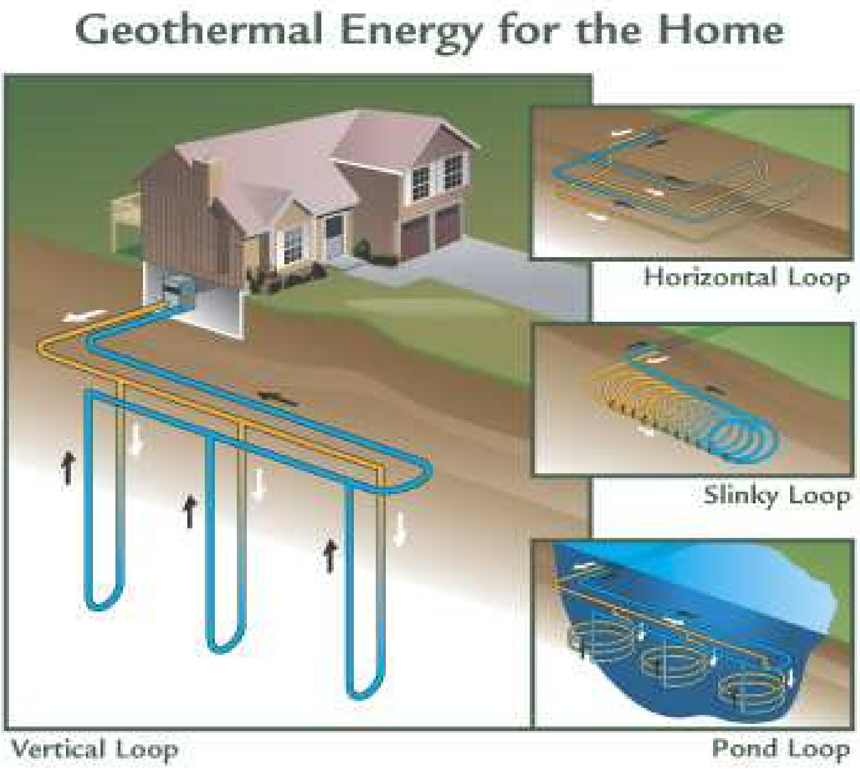
1. Conventional (hydraulic pressure) extraction
2. Ground heat exchange

The conventional extraction system was considered under high-temperature resource extraction and does not need any further review. Ground-source heat pumps, on the other hand, are still relatively unknown in New Zealand.

Ground-source heat pumps are not restricted to application within “geothermal” areas, as they are capable of harnessing the vast amounts of low-temperature thermal energy within the ground. This technology is now being used for domestic and industrial applications in America, Canada, Iceland, France, Sweden, Germany, Switzerland, Austria, Turkey, China and Japan. The technology operates in a similar way to a conventional heat pump – where heat is extracted from the lower-temperature ground outside a house and is pumped, at a higher temperature, inside to heat the interior space within the house. The ground is, effectively, acting as the “chiller box” in this scenario, but contains such vast quantities of heat that it will not suffer from any appreciable reduction in temperature from the action of the heat extraction pump. Only a relatively small amount of additional electricity is required for operation of the pump to circulate refrigerant fluid through the system. The vapour in the cycle can transfer up to four times the energy that it takes to circulate the refrigerant fluid and operate heat dispersion fans. A ground-source heat pump can be used for heating and cooling and can, thus, compensate for seasonal temperature variations. Various configurations for a domestic-scale, ground-source heat pump installation are shown in Figure 4.1.17.

Although a heat pump system (for heating and cooling) has been operating at the Rural Bank and Finance Corporation building in Hamilton for many years, this technology is only starting to become common use in New Zealand.

Figure 4.1.17 – Schematic of ground-sourced heat exchange



Source:www.daviddarling.info

4.1.4.6 Low-temperature resource – conversion system

There are numerous ways to use low-temperature geothermal resources. Worldwide, direct geothermal energy use is equivalent to 12,000 MW of electricity generation, most of which is for warm water, either directly or via ground-source heat pumps.

The three common intermediate / low-temperature direct use systems are:

- Process steam
- Hot water
- Ground loop

The status of these direct-use systems was reviewed by PB Power (2007). Table 4.1.18, below, summarises the conversion technologies covered in this report, highlighting status and trend of technologies, costs and implementation figures, and potential development or introduction of technology to New Zealand.

Table 4.1.18 - Status of direct use

		Process steam	Hot water	Ground loop
Technology maturity		Medium Limitations due to location of geothermal resource	Medium Heat exchange technology is mature Industrial (hybrid) technologies to develop	Medium Heat pump technology is mature Ground loop systems maturing
Cost data	Capital Costs	No typical cost details available Project related Direct-use particularly interesting when coupled with electricity production	No typical cost details available Project related Direct-use particularly interesting when coupled with electricity production (cascading of uses) For district heating, coupling with boiler for 100% coverage necessary	50 US$/m² for private housing No precise figures for bigger operations (industrial or office buildings / factor of scale will apply)
	O&M	Low for the geothermal loop side	Low for the geothermal loop side	Anticipated
Performance data	T>125 °C	Project related No typical value available	Project related No typical value available	N/A
	Low-T	Project related No typical value available	Project related No typical value available	Related to heat pump Coefficient of Performance.
Implementation	<2years	Less than 12 months for add-on to existing generating units	Less than 12 months for add-on to existing generating units	Less than 3 months (private housing) to 24 months (big building operations)
	2-5years	If new site, sub soil investigations Exploratory and production drillings	If new site, sub-soil investigations Exploratory and production drillings	
	>5years			
Trend in NZ	<5years	Paper mill and wood processing until now. Other applications to investigate	Actual limitation to Kawerau combined operations. Many other possibilities	Very low activity until now. Can develop rapidly.
	>5years			Prices for ground loop systems can reduce fast and boost implementation
Major Equipment	Suppliers	Typical BOP equipment suppliers	Typical heat exchanger manufacturers	For heat pumps: - Econar, Geoexchange (USA) - Viessmann, Dimplex (Germany) For ground loop tubing: - Egetherm, Gerodur (Germany)

NOTES: 1. Conversion efficiencies are from extracted thermal to generated electrical power.

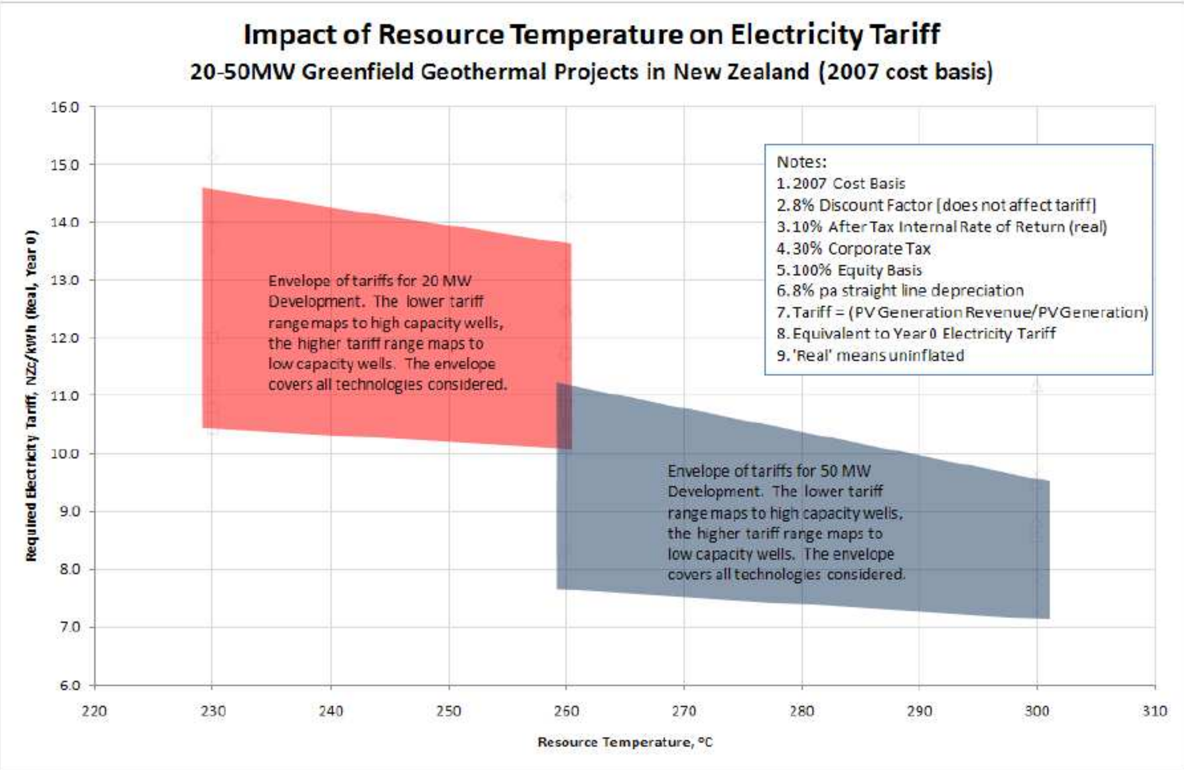
4.1.5 Asset characterisation

The geothermal assets in the EnergyScape framework are characterised with both an extraction facility and a processing facility. For the 'continuity scenario' the assets were characterised with the following basis:

- The growth potential in geothermal electricity generation to 2013 is based on published projections of the various power companies and reports from the New Zealand Geothermal Association. Growth beyond 2013 is speculative and awaits the outcome of current research both in New Zealand and internationally.
- Two years have been allowed for exploration, three years for consenting, and two years for designing, installing and commissioning a power station. Replacement wells are required during the life of the power station. Power station life is assumed to be 25 years, but the resource is renewable.
- Geothermal electricity generation is capital intensive since costs of drilling wells may exceed $5 million per well.
- Risk profile is considered to be low (this earns a rating of 3 stars, out of a total of five stars, for all phases within the rating scheme of the LEAP project).
- Areal footprint is considered minimal.

Barnett and Quinlivan (2009) have undertaken an in-depth assessment of the cost of geothermal electricity generation which related electricity tariff to resource temperature – See Figure 4.1.19.

Figure 4.1.19 – Costs of geothermal developments in New Zealand



Geothermal direct use:

- The growth potential for geothermal direct-use is based on published projections and reports from the New Zealand Geothermal Association.
- One year has been allowed for consenting and one year designing, installing and commissioning the heat extraction equipment.
- Risk profile is considered to be very low (this earns a rating of 0 stars, out of a total of five stars, for all phases within the rating scheme of the LEAP project).
- Areal footprint is considered minimal.
- The Kawerau pulp and paper plant uses a high temperature resource, whilst low temperature resource users include: The Prawn Park, Wairakei Resort Hotel, Wairakei Terraces, Ngawha timber mills, Ohaaki timber mills.

4.1.6 Research status

The worldwide acceptance that geothermal energy is a renewable, low-carbon-emission resource is encouraging higher levels of research into its greater degree of utilisation. Recent announcements include:

- Late in 2007, the US Congress approved US$70 million of annual research and development spending. There has also been significant renewed interest in the extraction of geothermal energy using Enhanced Geothermal Systems (EGS) as detailed in an extensive Massachusetts Institute of Technology report [MIT (2006)].
- In Australia, the projected expenditure for hot rock / EGS research over the next two years will exceed A$700 million. The Australian Government (December 2007) announced one-for-one subsidies of up to $50 million for geothermal research and development.
- The New Zealand government (late 2007 onwards) has allocated $2 million per year for high-temperature geothermal research, and a further $800,000 per year for direct-use applications.

During the 1990s, geothermal energy was considered a mature technology, but this has changed due to new extraction, generation and direct-use technologies being developed. Exploitation of geothermal resources in New Zealand is currently limited to less than 3 km depth, though temperatures and potential resource gains continue to increase with increasing depth. If geothermal electricity generation is to rapidly expand in New Zealand, more research into the areas of deep geothermal drilling and mitigation of environmental issues is needed.

Table 4.1.20 – Research status

(Green highlight indicates 'Fair knowledge', Amber indicates 'Could improve', Red indicates 'Knowledge gap exists')

	International	New Zealand	Comment
Deep resource identification	International Continental Drilling Programme via GNS	GNS, UoA, SKM	Government funding needed to support high-risk deep-drilling.
National thermal gradient map	Many international examples		Careful collation of all thermal gradient material needed, not just for deep geothermal – may also be applicable to relatively shallow direct use
Location of buried geothermal resources, which currently have no surface expressions	Strong links with international research for Magneto-Telluric and seismic surveying technologies	GNS, UoA, SKM	GlassEarth claims to have found several systems
Better identification of the boundaries between active geothermal fields	Strong links with international geophysical research	GNS	Approx. $1 million geo-physical / geo-chemical studies could clarify boundary situation between protected and potentially developable tier 1 /2 fields, such as Reporoa & Rotoma.
Environmental impact evaluation (surface features / subsidence etc.)	Strong links internationally	GNS, UoA	
Sustainability (corrosion, scaling, modelling)	Good links internationally	GNS, UoA, IRL	Optimal development of resources to ensure we maximise utilisation
Characteristics of surface soils and waters for heat pump applications	Technology has been developed	PB Power	Local data is needed for designers
Greater direct utilisation of geothermal resources	Stronger links required	GNS, SKM	Rather than convert the energy to electricity, greater use for process-heat for timber, dairy processing, etc., should be encouraged
Raised awareness and direct utilisation of waste heat from electricity generation	Stronger links required	Energy for Industry Demand, Response, Strata Energy, PB Power	Only a small proportion of waste-heat is currently utilised.
Raised awareness of direct-use of lower-temperature geothermal resources, which are not hot enough for electricity generation	Stronger links required	GNS, PB Power	Traditional low-cost of electricity has discouraged interest and investment in utilisation

4.1.7 Summary

4.1.7.1 Geothermal electricity generation

It is recognised that, during the 1980s, geothermal electricity generation had been overlooked by power companies, instead favouring generation using natural gas from the Maui gas field. In the next decade, electricity generation from geothermal resources is considered to be New Zealand's most viable, secure, renewable energy resource. The belated recognition of this potential will likely witness a significant increase in geothermal generation of electricity from the present 700 MW to 1,080 MW by 2012. A further 600 MW may be yielded using conventional extraction techniques and 2,500 MW if deep extraction is supported.

By exploiting the resources to greater depths (deeper than 3,000 meters), the heat potential could further increase geothermal electricity generation beyond 3000 MW. However, exploiting to such depths is high-risk. Greater research investment is required into technologies to locate and exploit our geothermal resources to greater depths and thereby reduce development risk.

If the hot, dry-rock and enhanced-permeability research that is currently being undertaken overseas is successful, then these technologies can significantly increase the geothermal resources economically exploitable in New Zealand. This research is cost-intensive, but it is important that New Zealand remains involved with these new developments to enable their use when ready.

New Zealand is in the top ten of world geothermal electricity production. New Zealand geothermal expertise is highly regarded, worldwide, although there is an acknowledged shortfall of new professionals entering this speciality.

4.1.7.2 Direct use

The current direct-use of geothermal energy in New Zealand could be around 10,000 MW, yet we currently only utilise around 5% of its potential. There is much benefit to be gained from greater utilisation of integrated heat systems. Rapid growth of such systems is essential to reducing our reliance on fossil fuel resources. Growth in direct-use utilisation can be achieved by:

- Increased public awareness of the technologies and benefits
- Increased research and mapping.

Section 4.2
Conventional oil

4.2 CONVENTIONAL OIL RESOURCES

4.2.1 General introduction

New Zealand has had a long association with indigenous oil production. Oil exploration in New Zealand started early in colonial times, and our first oil was produced from the Moturoa field (in New Plymouth) in 1866 – not long after the world's first well was drilled in Pennsylvania.

New Zealand's conventional oil resources can be characterised by:

- 1,105PJ of remaining proven plus probable indigenous oil reserves
- Principal reserve is located in the Maari-Manaia oil field
- 254 PJ of energy from oil was consumed in 2006
- This was 51% of the total energy consumed from all energy resources
- It was mainly used within the transport sector

Relative to some oil-producing nations, our endowment discovered so far is relatively modest, but there has been enough production to support underlying economic prosperity. New Zealand has reason to be optimistic about its oil future, since it has vast, relatively unexplored, offshore territories within which there remains huge potential for world-class oil fields to be found.

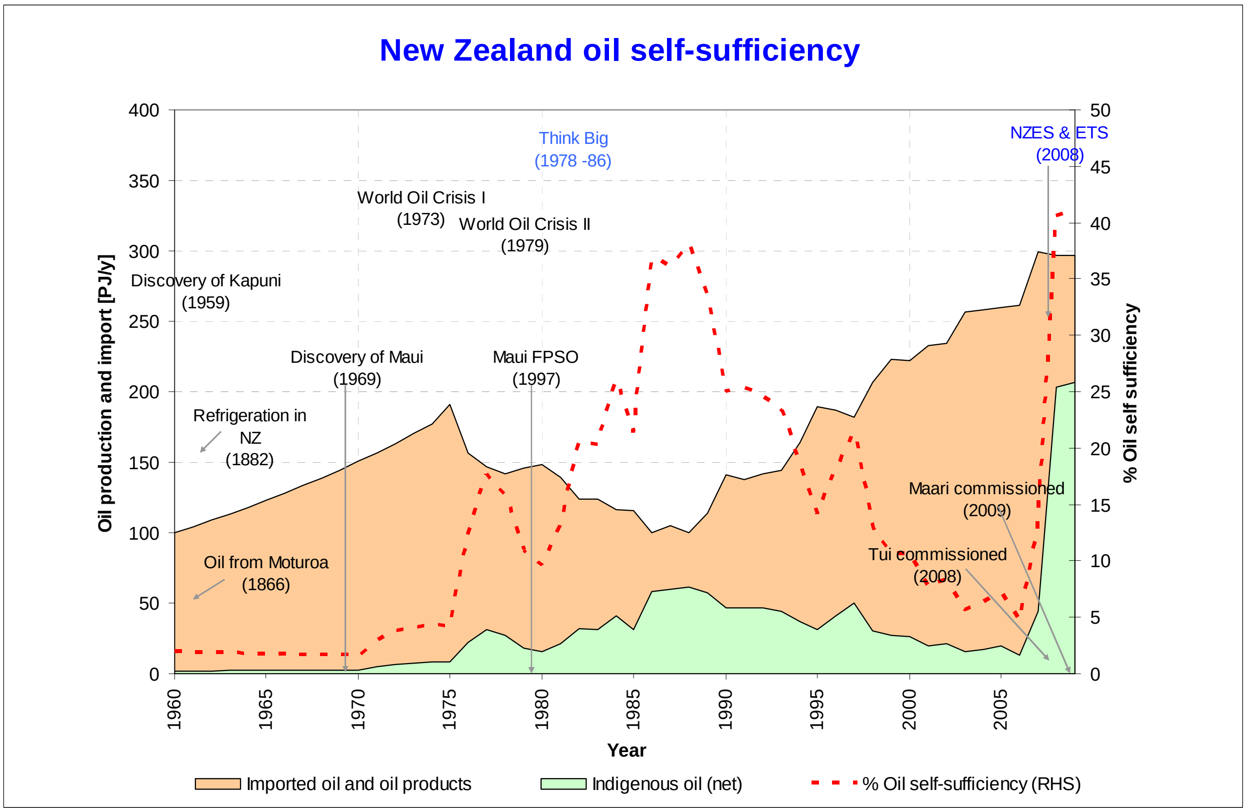
New Zealand has never been self-sufficient in oil production. After the nadir of "carless days", following the first oil shock of the 1970s aggressive exploration and development brought the McKee, Waihapa, Kaimiro and Ngatoro fields on-stream (see Figure 4.2.2). For a short period in the 1980s, New Zealand achieved nearly 50% net self-sufficiency in oil. Subsequently, self-sufficiency has declined steadily to less than 17% by 2005. This downward trend was remarkably reversed over subsequent years by Pohokura, Tui, Maari (formerly Moki) and Kupe field development (see Figure 4.2.1).

New Zealand has good reason to be optimistic about its oil future … there remains huge potential for world-class oil fields to be found.

Record annual oil and condensate production from New Zealand fields was attained in 1997 (see Figure 4.2.2) at about 21.5 mmbbl (121 PJ/year). This high-volume was attained as total Maui oil and condensate output rose to 16.6 million barrels, following the onset of production of oil from the Maui B platform. In 2006, sixteen fields produced a total annual production of 6.8 mmbbl (38.9 PJ) of oil and condensate, the main suppliers being Maui (56%), Kapuni (9%) and McKee (6%).

Total oil production for the 2007 calendar year was 14.8 mmbbls [MED (2008a)]. However, the Tui field was only producing for half of the year. Higher production volumes have since been achieved from full year production and in addition the Maari field has come on stream. Liquids are also being produced from Kupe.

Figure 4.2.1 - New Zealand's self-sufficiency in liquid petroleum production



Source: Data to 2007 is sourced from MED, 2008. The projections are approximate and depend upon the amount and timing of off-take from Pohokura, Tui, Maari and Kupe.

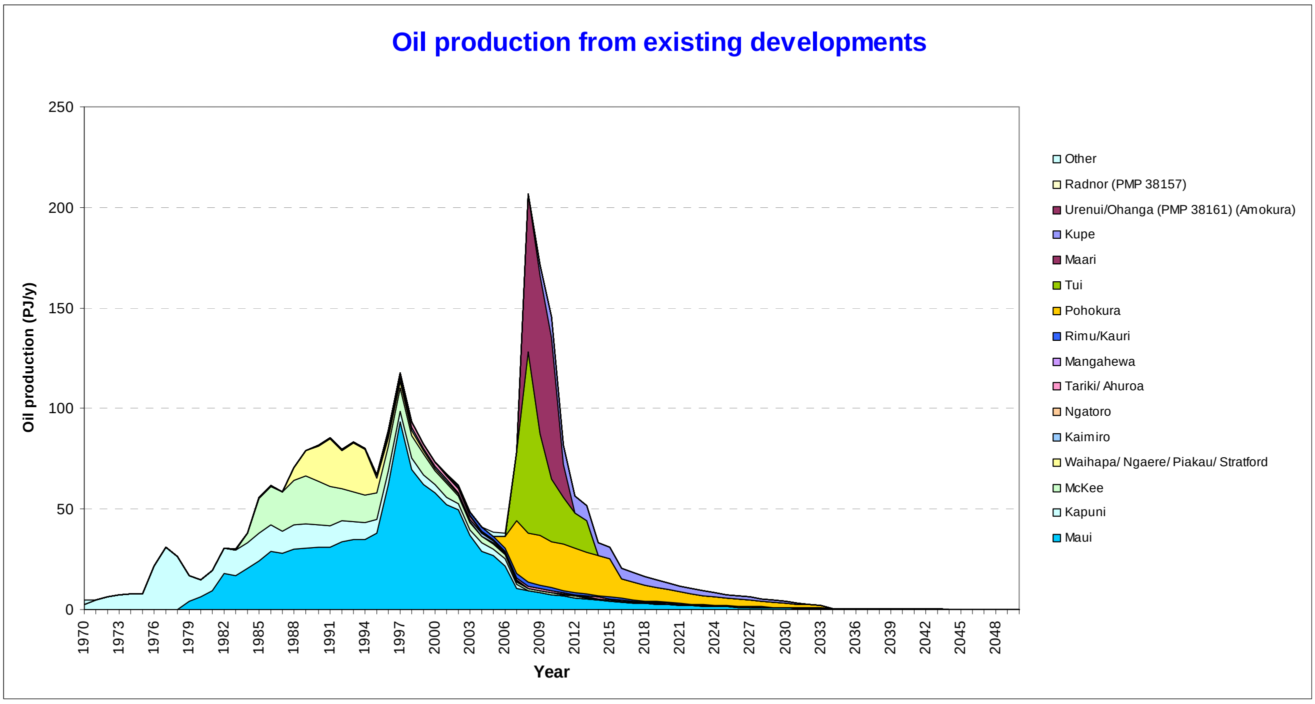
A new New Zealand record annual peak of about 28 mmbbl (156 PJ/year) is expected in 2008, once the Maari, Tui and Pohokura fields are all producing [Petroleum News.net (2007)]. Anticipated daily production rates are 8,200 barrels of condensate from Pohokura, 50,000 barrels of oil (101 PJ/year peak) from Tui, and 35,000 barrels of oil (71 PJ/year) from Maari. In addition, Kupe is expected to produce 4,650 barrels of oil and condensate / day once it comes on-stream, probably in 2009. This combined increase in local production could mean a $2 billion turnaround in the external accounts, providing global oil prices remain at, or close to, current levels[3].

It has been reported that the relatively high initial rates of flow from these fields will lead to New Zealand being about 60% self-sufficient in oil production in 2008 [Petroleum News.net (2007)]. This may be optimistic, and pre-supposes that all fields are producing simultaneously at maximum rates. Indeed, the apparent quadrupling of local production will be short-lived, due to the anticipated sharp decline in flow rates in ensuing years, particularly from the Tui Field. Nevertheless, the initial flow rates from Tui are the most prolific of any oil field in New Zealand.

In 2006, oil consumption was 254 PJ, and accounted for 51% of total consumer energy. Domestic transport accounted for 86% of total oil consumption. Total crude oil imported was 208 PJ, and total oil products imported was 93.6 PJ. New Zealand exported 33.5 PJ of petroleum liquids, and 4.3 PJ of petroleum products.

[3] Extract from Trans Tasman newsletter, week beginning 26 June 2006

Figure 4.2.2 - New Zealand's liquid petroleum production by field



Source: Data to 2007 is sourced from MED, 2008. The projections are approximate and depend upon the amount and timing of off-take from Pohokura, Tui, Maari and Kupe.

4.2.1.1 Investment in exploration and production

From 2000 to the end of 2007, the total annual expenditure for oil and gas exploration has generally been between $100 – 200 million. Production expenditure was similarly around $150 million per annum from 2000 to 2004, but in 2005 and 2006 it rose to over $550 million annually, and in 2007 was $1,350 million, as new offshore platforms were built [MED (2008b)].

The Taranaki oil and gas industry is a billion-dollar-plus earner and significant export contributor to the New Zealand economy. The oil and gas sector generates 17% of the gross domestic product (GDP) of the Taranaki region [BERL (2007)]. In the year to March 2006, the Taranaki oil and gas sector employed 817 full-time equivalent positions (FTEs) and generated $741 million. This slightly exceeded the contribution of the dairy sector to the Taranaki economy ($732 million). Nationally, the sector generated $827 million, or about 0.5% of national GDP. The 2006 Census recorded 1,607 people as working in the New Zealand oil and gas industry [PEPANZ (2008)]. The full impact of the Taranaki-based petroleum sector is much broader than this, given that many other industries or service companies depend on it. The "spin-off" value of petroleum amounts to a total of $1 billion to the Taranaki economy and employment of almost 3,000 FTEs. Similarly, petroleum contributed $1.6 billion to the New Zealand economy and employed over 8,600 FTEs. The Government has received nearly $1 billion in petroleum production royalties and energy resource levies in the period 2000 to 2006. If the Maui gas field was discovered today, it would have a total worth in the order of $59 billion (at $7.9/GJ and US$90/bbl).

4.2.1.2 Quality of the resource

New Zealand crudes are noted for their low-sulphur content and, hence, are highly desirable as a refinery feedstock. New Zealand crudes tend to be quite waxy. This characteristic has required heated oil field container tanks and the addition of pour point depressants to some crude oils prior to pumping through cross-country pipelines.

Table 4.2.3 - Energy densities (Gross / LHV) of New Zealand oil resources

	kg/m^3	MJ/kg
Kaimiro Crude	794	46.37
Kapuni Condensate	766	46.75
Mangahewa	806	49.83
Maui Condensate	739	47.12
McKee Crude	832	45.83
Ngatoro Crude	854	37.05
Pohokura Crude	777	46.56
Tariki-Ahuroa	794	46.37
Tui Crude	813	47.60
Waihapa Crude	886	44.80
General Product LPG	536	49.51

Source: June 2009 Energy Data File

4.2.1.3 Pathways

Indigenous oil is sourced from a reservoir via a wellhead. The wellhead can either be located onshore or on an offshore production platform. Modern directional drilling techniques have meant that oil reservoirs up to 20 km offshore[4] can be recovered by onshore wellheads. The hydrocarbon fluids recovered at the wellhead are often saturated with water and arrive at the surface in multiple phases (gas and liquids). The recovered fluids are transported with gathering flow-lines to primary separation units.

Primary separation units undertake initial separation of oil, water and gas phases (and sometimes solids). Further oil / water separation is achieved through settling in storage systems. Storage in onshore facilities is usually undertaken in carbon steel, non-pressure tanks, which may be heated or insulated as necessary. Offshore facilities use a Floating Production, Storage and Offloading vessel (FPSO) or Gravity-Base Structure (GBS) for storage.

Product refinement is achieved by further separation of gas, water, condensate and Liquefied Petroleum Gas (LPG), via settling and distillation, prior to Reid Vapour Pressure (RVP) stabilisation (which adjusts the volatility of a hydrocarbon liquid through the addition of additives).

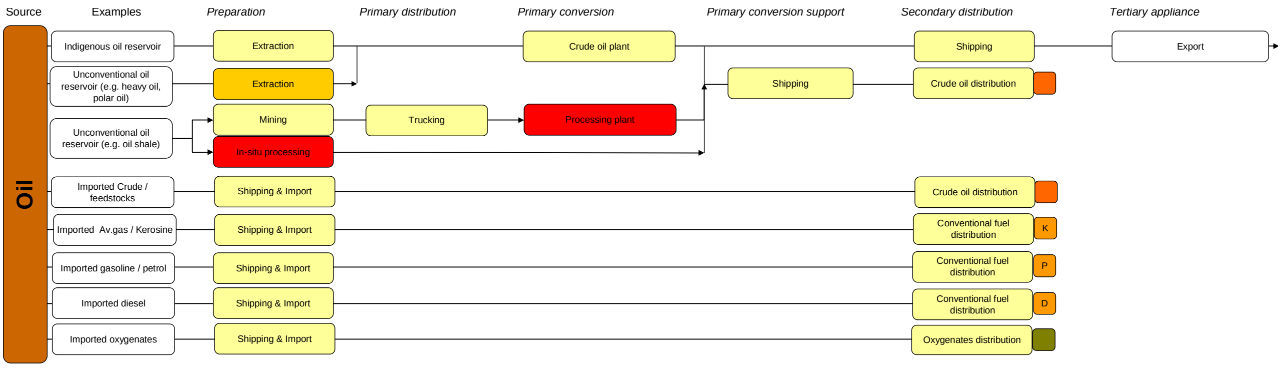
[4] 20 km is at the extreme end. The Manaia well was 7.95 km.

The crude oil product is then distributed for export or distributed to a domestic refinery by either pipeline or road tanker.

The refining process is too complex to characterise here, but involves storage, further product separation and upgrading. Ultimately, the refinery products are stored, blended with other products for market, and then distributed by pipelines and road tankers to distribution company depots.

The primary end-use of oil products is transport. Air transport generally requires Jetfuel or Avgas, although some diesel is used. Heavy-freight generally requires diesel. Domestic vehicles are predominately petrol, although diesel is increasingly becoming popular. Ships generally use bunker fuels and fuel oils.

Figure 4.2.4 – Oil production and utilisation pathways



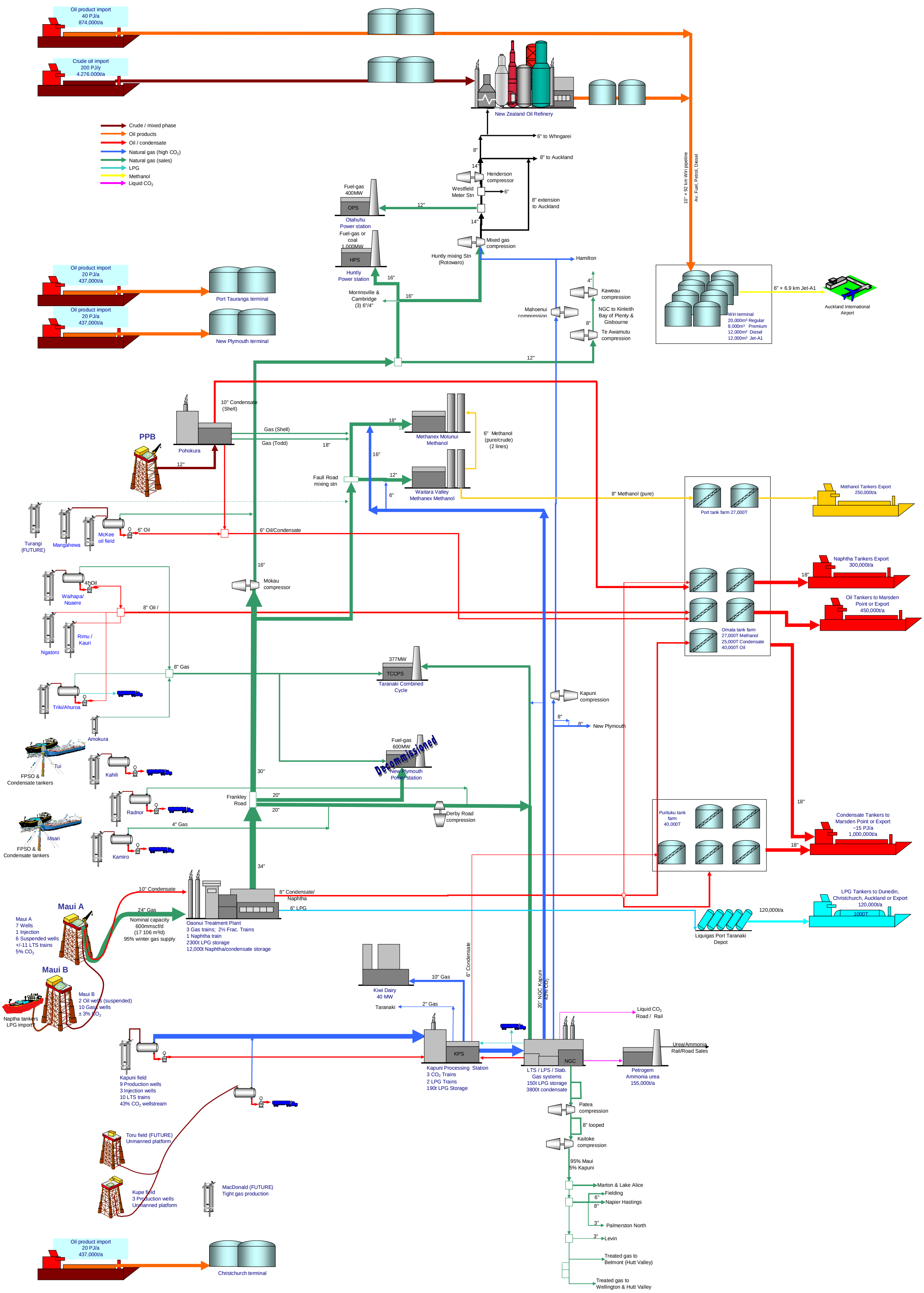
A full view of the pathway is presented in the Pathway Overview Map at the start of this document.

The pathways for condensate are similar to oil, except that, in addition to being of value as a refinery feedstock, some naphtha and middle distillates are of greater value as a petro-chemical feedstock. Enhanced naphtha is a “narrow cut” component of Maui condensate separated at the Maui Production Station gas processing plant and, currently, exported.

Liquefied Petroleum Gas (LPG) is becoming increasingly important product for use in heating and cooking in areas where reticulated gas is not available, and is also an important transport fuel for custom converted light vehicles. The LPG pathway is similar to oil except that it must be transported and stored in either pressurised or refrigerated equipment. LPG, which is a mixture of propane and butane, is fractionated from condensate and is stored as a liquid in pressurised bullets, both in the gas processing plants at Port Taranaki and at LPG terminals around the country. Local transportation of LPG between the gas plants and LPG terminals is mainly by pipeline and coastal tanker, but road and rail tankers are also used.

During the peak of Maui production, New Zealand was an LPG exporter. As production from this field declined, so did our export capacity. New Zealand is now predominantly an LPG importer - mainly from Australia. With the completion of the Kupe development and a potential expansion of LPG extraction activities at the Pohukura field, it is expected that New Zealand will once more become a net exporter of LPG, albeit at a rather modest scale.

Figure 4.2.5 – Schematic of New Zealand oil and gas assets

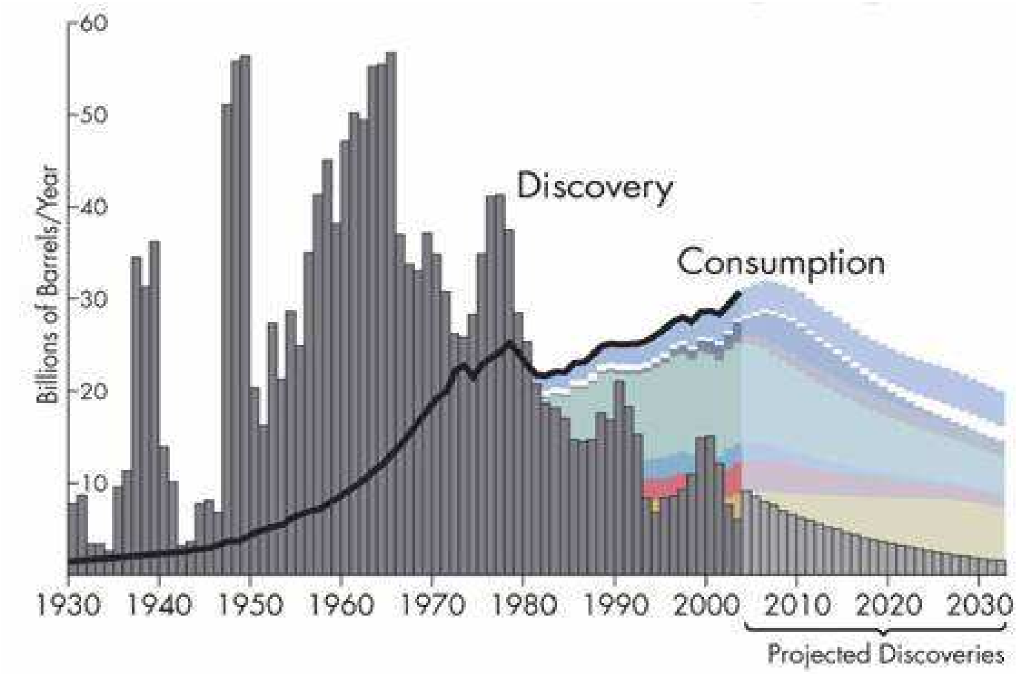


An A3 version of this figure is provided in Appendix A.

4.2.1.4 Myth busting

The most pervasive myth associated with oil production, both internationally and domestically, is the belief that oil, particularly cheap oil, will last forever. Since the economic function of most western societies is tightly linked to this resource, there is a great deal of interest in forecasts of future oil production potential. The concept known as “peak oil” identifies that the issue of greatest concern is not when the resource will be depleted (i.e. all used up), rather when oil production rates can no longer be increased sufficiently to meet oil demand.

Figure 4.2.6 - World oil production and world oil discoveries for the period 1930 to 2050



Source: Past discoveries based on ExxonMobil (2002), 3 year moving average and compiled by Colin Campbell. ASPO Switzerland http://www.peakoil.ch/new/e/wirdwenigergefunden.php

“We will not run out of oil, just run out of oil at a price we can afford”
Matt Savinar, Life after the oil crash

From the perspective of national economic resilience, if oil supply cannot keep pace with demand then economies must either reduce demand, utilise less convenient alternatives or accept higher prices, price volatility and supply disruption. There is a very large community of experts constantly provide forewarning of the catastrophic implications for economies attempting to respond to oil supply – demand tension. Currently, the political response to the threat primarily takes three forms: (i) A call for greater international information disclosure i.e. to enable better prediction of when / how rapidly impacts may be experienced; (ii) Provision of stimulus for domestic oil exploration; (iii) Support for the development of alternative mobility technologies / fuels.

Evaluation of the effectiveness of these policies with regard to reducing the supply – demand tension threat is beyond the scope of this project, but there can be no doubt that New Zealand’s energy future will be heavily influenced by trends in world oil supply – demand tension (and subsequent impacts). The EnergyScape framework treats world oil price as the proxy for world supply – demand tension, and thereby enables evaluation of the implication of different oil price and 'peak oil' timing expectations.

As with many of the politically challenging issues, the publicly available literature presents a variety of contrasting and opposing views:

- The major oil suppliers in the Middle East gain financial advantage from mis-information regarding oil reserves and production rates.
- Oil exporting countries have growing domestic consumption and will satisfy that first.
- Large proportions (often in >20%) of the work forces of western economies are employed in industry directly linked to oil e.g. vehicle manufacture; petroleum exploration.
- The production of oil from coal, gas and biomass (see Section 6 - Secondary conversion) takes considerable time to develop (due to need to find capital, skills and resources).
- Estimated future production prices often do not account for increased labour, fuel and material costs.
- Production of alternative fuels / mobility technology may be limited by resource (e.g. land area, rare earth materials)
- Countries with greater import dependence will be most affected by oil price shocks, unless the value of their exports increases proportionally.
- Lobbyists who raise doubts about the validity of detail (and thereby delay action) often neglect how history can verify core principles.
- New Zealand's petroleum sector is fully integrated into the world oil market and therefore the consumer prices for petroleum products in New Zealand will continue to reflect world oil price.

Perhaps the biggest misconception within the overseas exploration community is that New Zealand is a gas exploration province. This "prejudice" is a powerful disincentive for exploring in New Zealand for many companies. The argument is partly historical and empirical, in the sense that the early big finds in New Zealand (Maui, Kapuni) were primarily gas / condensate. The paradigm also stems from the knowledge that New Zealand petroleum source rocks are coal-rich. In the northern hemisphere, coals (primarily of Permian-Carboniferous age) are mainly gas generative. However, the much younger (Cretaceous to Tertiary-aged) coaly rocks in New Zealand (and Gippsland and SE Asia) are proven sources for oil.

Another standard "rule of thumb" in the oil industry is that "the big ones are always found first". Based on discoveries to date, this appears to apply in New Zealand, as Maui was found early in this country's modern exploration period. However, the argument is still moot in New Zealand, because there are vast tracts of un-drilled acreage. Those areas that have been drilled (outside Taranaki) have so few wells that they are still effectively in the "virgin" phase of exploration. Moreover, there are too few discovered fields from which one can statistically conclude that there are no more big fields to be found here. Further, the second largest resource, Pohokura, was discovered only recently.

It has also been shown elsewhere that new exploration concepts and new technology can lead to rejuvenation of old exploration areas, with significant new reserves being found. Indeed, the current and projected increase in oil production from new fields over the next few years attests to the fact that New Zealand’s indigenous oil supply is far from being in permanent decline. In fact, there has always been an erratic discovery profile for oil in New Zealand. Significantly-sized oil accumulations were found in 1979 (McKee), 1987 (Waihapa), 1999 (Rimu) and 2003 (Tui). The oil leg of the Maui field was not found until 1993, 24 years after the original gas / condensate discovery. This episodic discovery history and the relatively consistent sizes of fields found further imply that we are not yet “scraping the bottom of the barrel” in terms of the potential for future significant finds.

Another popular wisdom is that offshore fields need to be big in order to be profitable, and take a very long to come on stream. The Tui field came into production only four and a half years after its discovery, easily the quickest development in New Zealand’s modern petroleum history. It is a reasonable size (~50 mmbbl recoverable i.e. 318 PJ) and, although it had the geologic potential to produce at 100,000 bbl/day (from 4 wells) in the early phases of its life, operational production rate was constrained by the off-take facilities to 50,000 bbl/day (112 PJ/y). In its first 11 months of operation, the field produced 14.2 million barrels of oil [AWE (2008a)]. Depending on the price of oil, the overall value of the field is several billion dollars. The payback time for the US$274 million development cost was a mere five months [MED (2008c)].

4.2.2 Introduction to the resource

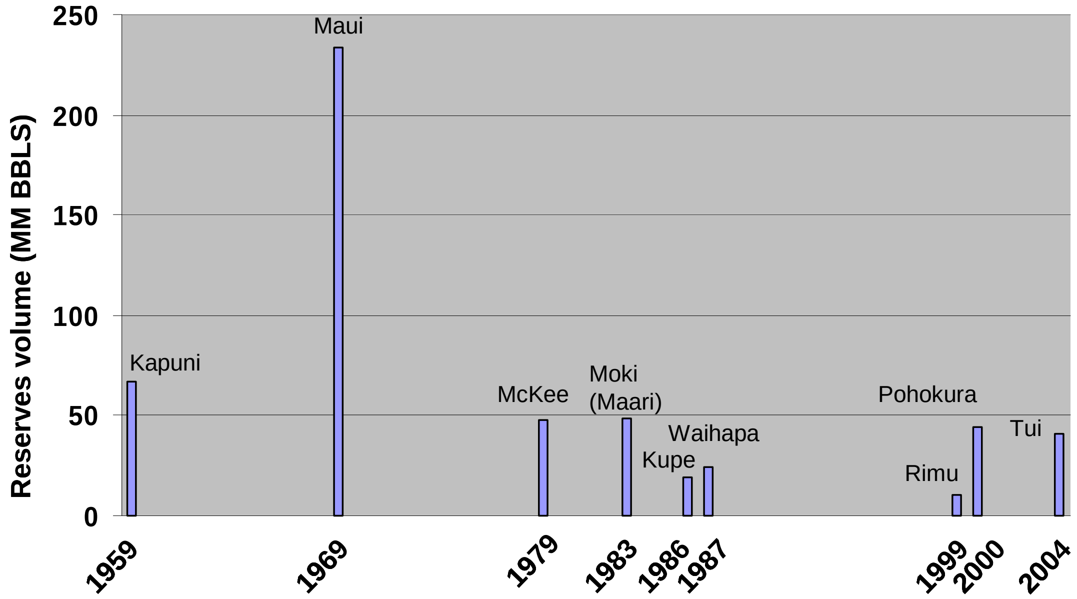
Oil seeps on the New Plymouth foreshore were known to Maori and early European settlers in the mid-1800s. The shallow Moturoa field had its heyday in the 1940s and still continues to produce small amounts of oil. The oil field has never supported major enterprise, nor has it been a significant commercial success. The field is undergoing renewed drilling and production, albeit still at small but economic scales, given the currently high oil price.

Although the initial Kapuni and Maui discoveries included significant volumes of condensate, the first relatively large oil field in New Zealand was McKee, discovered in onshore Taranaki in 1979, two decades after Kapuni and one decade after Maui.

The largest offshore oil discoveries have been at Maari (formerly named Moki; 1983), Maui B (1993) and Tui (2004), whilst the largest onshore oil fields have been McKee and Waihapa (1987), with minor production from Rimu, Ngatoro, Kaimiro and other small fields.

Figure 4.2.7: Discovery sequence of liquids (oil and/or condensate).

Note that the Maui reserves included condensate and Maui-B oil (approx. 35 million barrels) which was not discovered until 1993. Field size cut-off is 10 million barrels.

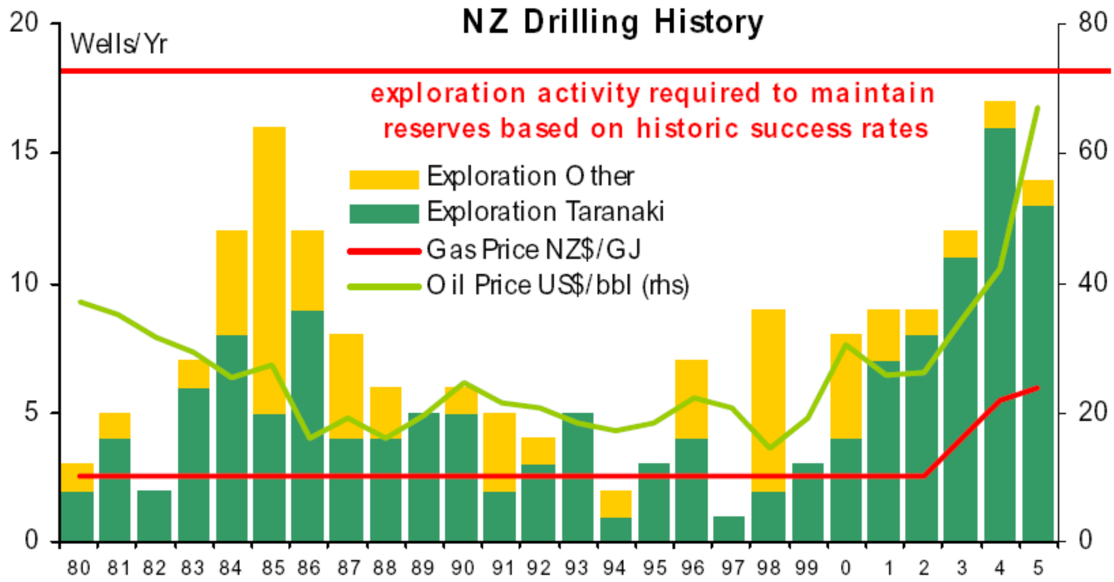


To date, Taranaki is the country's only petroleum producing province. However, oil and gas have been found in sub-commercial quantities in the East Coast, West Coast, Canterbury and Great South basins. Compared to most other oil producing countries, New Zealand is "unexplored" and, as such, considered an oil frontier by the international industry. Even the Taranaki basin is considered to be under-explored, especially offshore.

New Zealand's basins have traditionally been of little attraction to major international oil companies, with a few exceptions, because of our geographical remoteness, the depth of surrounding seas, the tough meteorological-oceanic conditions (caused by our location in the belt of the roaring forties) and lingering perceptions that New Zealand basins are gas prone. It is only recently that the jump in the price of oil, coupled with a recently announced more favourable tax regime, and our political stability (compared to some other oil prospective countries), that there has been an upsurge in interest from overseas companies, as well as an increase in local drilling activity (indicated in Figure 4.2.8). Over the period from 2004-2007, the average number of wells drilled per year was 27 onshore and 8 offshore, which is a marked increase compared to the average of 16 onshore and 3 offshore wells from 1999 to 2003 [MED (2008d)].

Figure 4.2.8 - Number of wells drilled in New Zealand since 1980

The top red line indicates that 18 wells need to be drilled per year to replace reserves. The drilling activity peak in the mid-1980s coincided with the tenure of the government-owned Petroleum Corporation of New Zealand (Petrocorp).



Source: Chris Stone's talk: "New Zealand Energy Balance, 2006 New Zealand Petroleum Conference

In July 2007, the New Zealand government awarded five permits in the Great South basin to three consortia whose exploration work program commitments involve spending over $1.2 billion over the next five years.

Licence holders in the deep-water Taranaki Basin are currently promoting that area with a view to obtaining partners to acquire new seismic data. Offshore exploration activity is increasing in Canterbury, Hawkes Bay and Northland, and various announcements have been made on the identification of, and drilling plans for, large prospective structures. Given the proven discoveries in Taranaki, and with enough encouraging geological similarities with Bass Strait in Australia, there are realistic prospects of new discoveries.

4.2.2.1 Reserves

The current New Zealand oil reserves are tabled in successive versions of the Energy Data File and are summarised in Table 4.2.9 below for the status as of January 2009 [MED (2009)]:

Table 4.2.9 – Summary of reserves and production as at 1 January 2009

	Ultimate recoverable (P50)		Remaining (P50)	
	mmbbls	PJ	mmbbls	PJ
Producing fields				
Maui	161.3	974.3	11.1	67.3
Kapuni	65.2	287.5	1.9	8.4
Pohokura	59.4	n.a.	49.2	309.5
Maari	51	320	51	320
Tui	50.1	318	30.3	192.7
Kaimiro / Moturoa	5.2	33.4	1.8	9
Ngatoro	8.2	52.1	3.3	20.9
Tariki / Ahuroa	6.2	38.5	0	0.2
Waihapa / Ngaere	24.2	147.8	0.1	0.5
Rimu	10.4	63.8	1.8	10.1
McKee	47.7	308.8	0.9	5.4
Mangahewa	2.8	17.9	2.3	13.8
Others	8.9	53.6	8.4	50.6
Sub-total	**500.6**	**2,615.6**	**162.1**	**1,008.4**
Non producing fields				
Kupe (PML 38146)	19.2	95.4	19.2	95.4
Urenui/Ohanga (PMP 38161)	0.3	n.a.	0.3	n.a.
Radnor (PMP 38157)	0.2	0.9	0.2	0.9
Sub-total	**19.7**	**96.3**	**19.7**	**96.3**
Total	**520.3**	**2711.9**	**181.8**	**1104.7**

Source: June 2009 Energy Data File

As at January 1, 2009, total remaining oil / condensate reserves in Taranaki was 162 million barrels in producing fields, with another 19 million barrels in the yet-to-be developed fields such as Kupe [MED (2008e) June 2009 EDF, Table H.2b]. Remaining reserves for Tui are recorded as 30 mmbbls, which accounts for the reserve upgrade from around 28 mmbbls to 50 mmbbls (once the field started production), less the amount of production from field inception in late July 2007.

Of the fields that have recently started (Kupe, Maari, Pohokura and Tui), production, only the Tui field is genuinely new, having been discovered in early 2003. Conversely, the Maari field (originally named Moki) was known about for a quarter of a century by the time it produced its first oil. The field's reserves were previously considered to be insufficient to warrant development, but it is now commercially viable due to the escalating value of oil and through improved drilling and offshore completion technology. The final decision to produce Maari was based on expected recoverable reserves of 50 mmbbl (306 PJ). It was recently announced that the field and a satellite accumulation could hold up to 87 mmbbl (532 PJ) of recoverable oil [MED (2008f)].

The Tui field has an overall lifespan of approximately 10 years, with half of the oil to be produced in its first 2-3 years. The expected life of the Maari field is also about 10-15 years, although the mining licence has been awarded for 22 years. The Kupe and Pohokura fields will produce for about 15 - 19 years (although they are primarily gas / condensate fields). Irrespective of the production duration of these new fields, they are too small to cater for all of New Zealand's oil requirements. In the absence of some very prolific large scale finds in the future New Zealand will remain a net importer of oil well into the future.

4.2.2.1.1. Reserves calculation

Petroleum reserves are notoriously difficult to quantify. They are defined in the first instance as the volume of oil or gas / condensate that can be physically recovered at the surface. They are therefore different to "resource", which refers to the commodity present in the ground. The first step in calculating reserves, however, is to infer the volume of the resource initially in the ground (i.e. before production). This initial volume is approximated as a simple multiple of mapped or inferred parameters [(reservoir area) × (thickness) × (inferred porosity)]. An estimate of the amount of oil saturation (cf. water) within the pore spaces must also be applied which, if less than 100%, will further reduce the predicted ultimate volume of petroleum to be extracted. None of these parameters is known with certainty before drilling. Moreover, given the geological complexity of the reservoirs in Taranaki, the parameters delineated after drilling could still be quite variable away from the well location.

The estimated physical volume in-situ is then adjusted to account for volume changes as the oil or gas is brought from subsurface temperatures and pressures to those at the surface. In addition, the ultimately recoverable volumes are reduced by a factor that approximates the amount of oil or gas that can actually be extracted from the reservoir, given that some remains trapped and left behind, either in stratigraphic reservoir pockets, structural fault blocks, or as residual hydrocarbons within pore spaces. The recovery factor applied for oil is generally less than 20 – 50%, depending on the quality of the reservoir and type of oil. Ultimate recovery not only depends on geological factors, but on the technology used, the amount of hole exposed to the oil column, off-take rates, and natural pressure drive efficacy.

Reserves are often listed as "Proven", or "Proven and Probable" (2P). Proven reserves refer to those established through drilling and flow testing and, generally, are assigned a 90% probability of being present. Proven and Probable reserves are more speculative and larger than Proven reserves and include volumes extrapolated from well data and / or inferred from geological mapping and statistically-based assumptions of reservoir parameters. Proven and Probable reserves are accorded a 50% chance of being present.

Reserve estimates also change and become increasingly reliable during a field's production history, as reservoir performance can be empirically monitored. In some cases the initial estimates of reserves turn out to be too optimistic, whilst in other cases additional reserves may be booked, as happened with the Tui development.

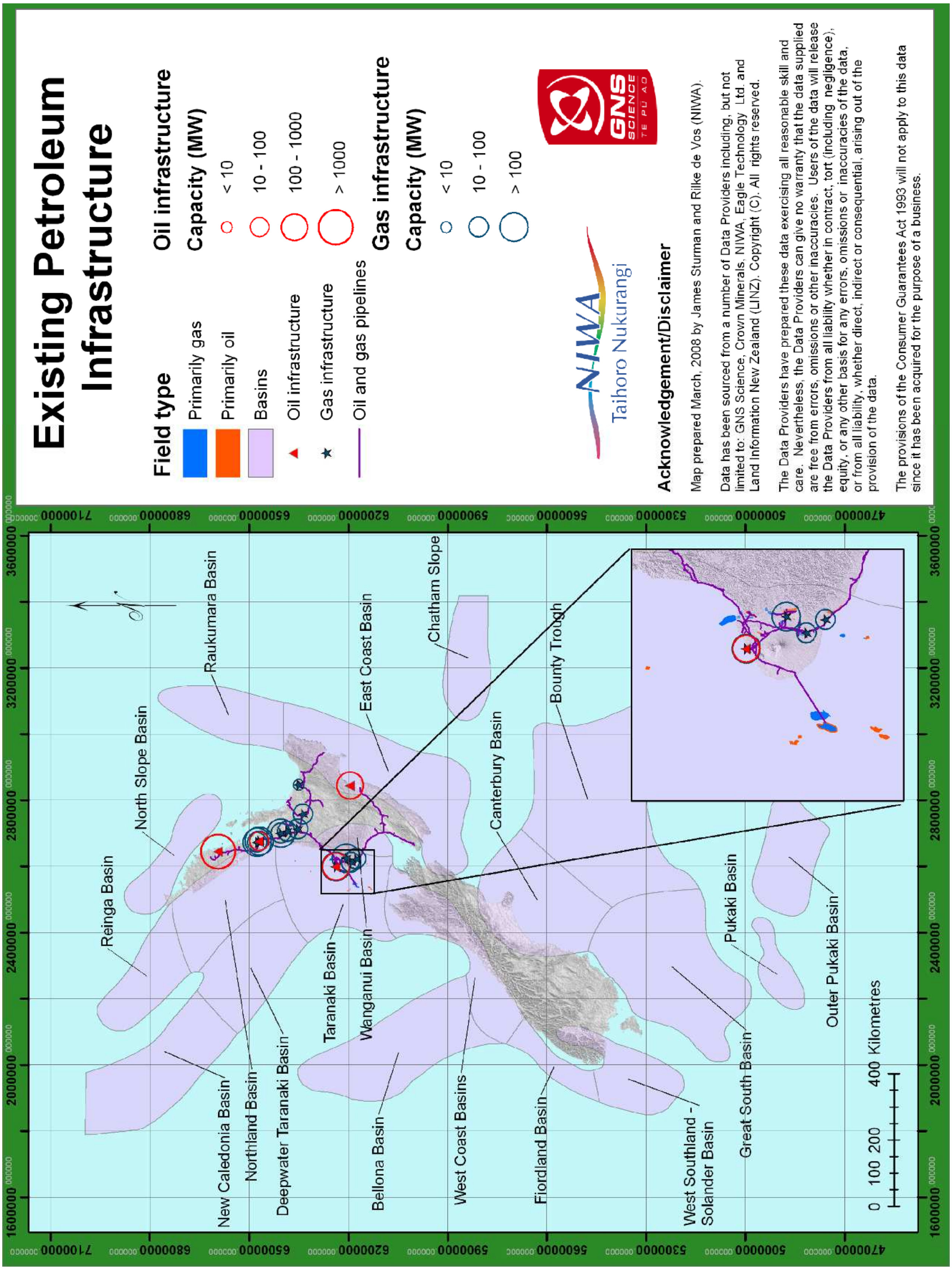
Reserves estimates are also inter-connected with economic factors. Reserves are assets for any company, and hence are commercially sensitive. The reserves inventories listed by companies are influenced by, and have a bearing on, investment markets, commodity prices, infrastructure investment, government policies, and on the levels of ongoing exploration activity within the marketplace. Accurate information is required for modelling future energy scenarios and planning of appropriate infrastructure and the New Zealand Government is currently calling for more open and frank disclosure of reserves.

The global or local commodity price in turn influences the economics of extraction. That is, if the price soars, recoverable reserves that were hitherto considered to be uneconomic might then become economically viable. Similarly, it might become economic to increase the levels of ultimate production from established fields, either through drilling of additional off-take wells, or application of enhanced recovery operations (e.g. gas or water injection to rejuvenate sub-surface pressures etc.).

In other words, the true definition of an accumulation of oil as “reserves” hinges on geological, technological and economic factors. The “exact” amount of reserves in any given field will not be known until the field is depleted and abandoned.

Figure 4.2.10 - Existing petroleum infrastructure

The location of significant petroleum infrastructure (oil and gas users and oil / gas pipelines) in the context of discovered fields and frontier exploration basins.



4.2.2.2 Resource uncertainty

The true volume of New Zealand's oil and gas endowment will never be known unless every conceivable habitat for oil and gas is drilled, which is improbable at best. The resource is hidden in the sub-surface, and the area within which oil and gas might be found is huge. Moreover, 96% of New Zealand's Exclusive Economic Zone (EEZ) and extended continental shelf (ECS), is under water, which increases the logistical cost of exploration. New Zealand's marine territory is about ¾ the size of Australia and there are still tens of thousands of square kilometres that are totally unexplored. The cost of offshore data acquisition and interpretation is non-trivial. At least $50 million is required over the next decade.

In addition, New Zealand's geology is complex, being that it is astride an active tectonic plate boundary. This means that the various geological parameters required for oil and gas to form are also complex (they include: source rock structures, from which petroleum is generated and expelled; migration pathways, along faults or permeable carrier beds; reservoir rock, where it is stored; trapping structures and sealing cap rocks). These parameters are all highly variable in a vertical, stratigraphic sense and spatially, within basins and from basin-to-basin.

The bottom line is that no-one knows the full areal extent of petroleum occurrence or the total volume of oil and gas reserves that could be at New Zealand's disposal. Most "guesstimates" are just that. Many, many more exploration wells are required across New Zealand as a whole before we can attain a more complete empirical understanding of our in-ground petroleum resource and producible reserves.

There will be, of course, many more fields present in the subsurface than will be found, no matter what. Only structures or stratigraphic traps of reasonably large size will be drilled in the first place. The pre-drill size cut-off will depend mainly on economic factors, such as: current market supply and demand balance; proximity to market and infrastructure; remoteness from industrial engineering bases; availability of rigs; commodity prices; political policies etc.

4.2.2.2.1. Estimation of resource extent

Maps of sediment thickness (above non-economic basement rocks) provide a "first-look" proxy for evaluating the petroleum prospect of a region or basin on the premise that if the sediment cover is too thin, petroleum will not have been generated. These maps are derived from seismic reflection profiles or from data on the region's gravity field. With either data source, geological assumptions and mathematical algorithms are required to convert the input data to inferred sediment thickness.

The threshold sediment burial depth below which oil and gas generation may have taken place can be deduced using a sophisticated computational method, broadly termed "basin modelling". This method calculates predicted volumes of oil or gas generated from inferred source rock "kitchens" over specified depths, geological times and geographic areas. The input data are again based on subsurface mapping and a large number of geological assumptions, such as the type of source rock, geothermal gradient, depth of source rock burial and duration of burial.

Basin modelling can also discriminate between the likelihood of oil versus gas being found. This method allows explorers to prioritise areas to drill in, but on its own does not predict the exact location or size of individual future discoveries. A rule of thumb in New Zealand basins is that only about 1% of the generated hydrocarbon volume is ultimately retained within traps.

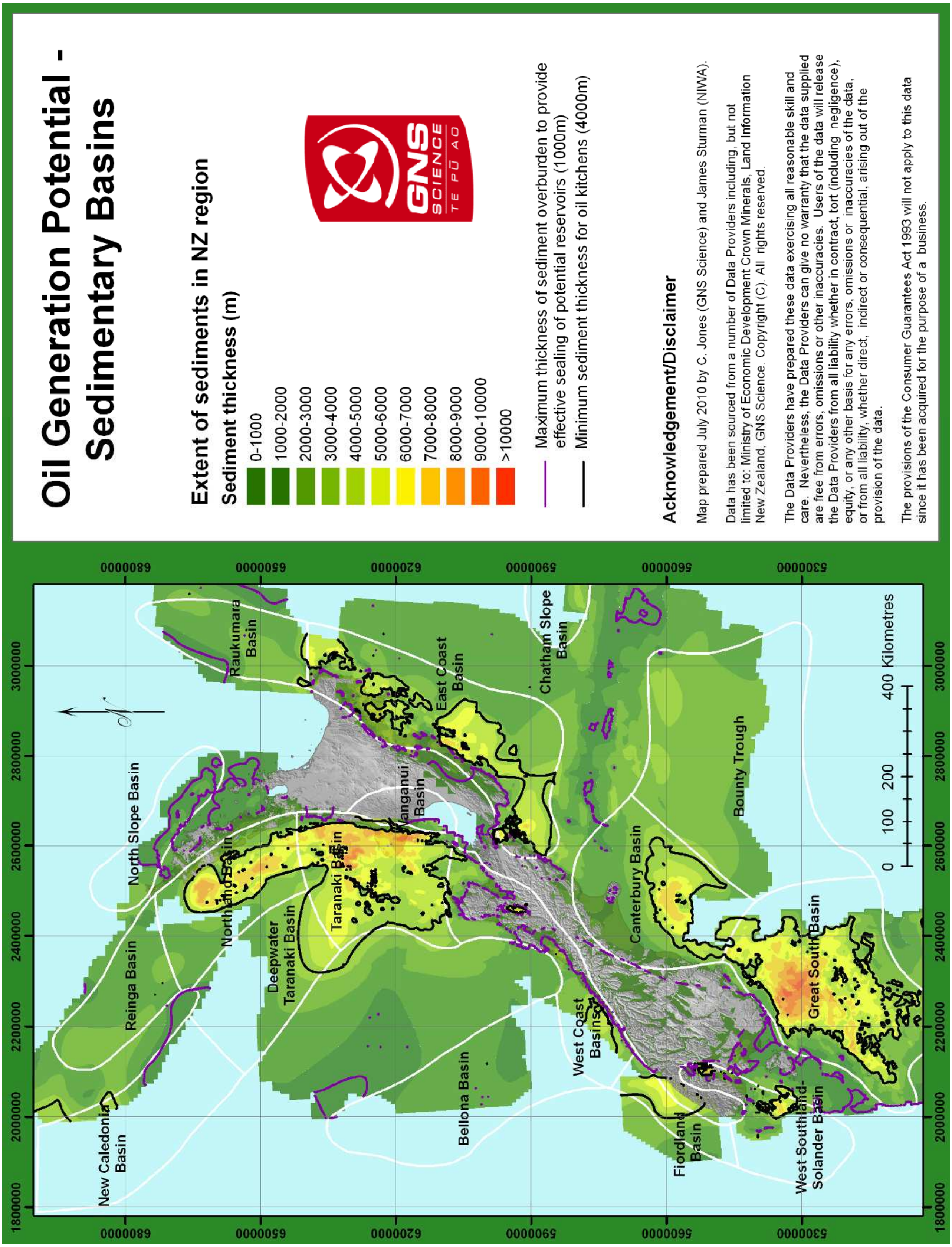
Figure 4.2.11 shows a simplified sediment thickness map of the basins around New Zealand. Another rule of thumb is that source rock in New Zealand needs to buried to at least 4,000 meters depth below the surface before oil generation and expulsion from source rocks begins. Therefore, any region on the map with a sediment thickness of >4,000 meters can be regarded as a potential oil kitchen (assuming the presence of suitable organic-rich source rocks). The main oil "window" is generally between 4,000 and 5,000 meters depth. In areas with very thick sediment accumulations, organic-rich strata buried deeper than 5,000m may have generated oil in the geologic past, but are now likely to be in the generation window.

The oil may have then migrated up-dip to shallower horizons, where it is either trapped or escapes to the surface. As another approximation, at least 1,000 meters of overburden is required above any possible hydrocarbon accumulation in order to provide enough compaction of capping sediments to provide an effective top-seal for the trap. Accordingly, a cut-off of 1,000 meter sediment thickness is defined here as the peripheral limit of possible petroleum occurrence (Figure 4.2.11). In other words, hydrocarbons might be found anywhere with sediment greater than 1,000 meters, provided that there is also a nearby "kitchen" area and suitable migration pathways in between.

Although the map shows a vast area covered by sediment, when one applies thickness cut offs, and migration distance limits, the realistic area for petroleum exploration is diminished. The prospective areas for petroleum lie primarily offshore, with the exception of relatively small areas onshore in Taranaki Peninsula, coastal Hawkes Bay and Wairarapa, and in western Southland (Figure 4.2.11). The main offshore areas are Taranaki, Northland, East Coast (including north of Raukumara peninsula), Canterbury, Great South Basin, Puysegur Basin (west of Stewart Island), and south Westland. It should be noted that sediment thickness data for Wanganui Basin data is unavailable, and that new data from offshore Raukumara peninsula indicates greater sediment thicknesses than those shown.

Figure 4.2.11 - Oil generation potential

The regions for potential oil generation can be bounded by regions with sediment thickness between 4,000m (black contour) and 5,000m.



4.2.2.2.2. Estimation of undiscovered reserves

There are several ways of estimating undiscovered reserves, none of which is robust in under-explored regions.

One method involves a Delphi analysis, or consensus expert opinion by several experienced petroleum geologists. This technique is simply a first-pass filter and is most useful for comparing the prospects of different basins or countries. Results can be quite varied, and are generally not based on detailed mapping of target structures.

A second method involves a statistical gap analysis, which predicts the sizes of missing (undiscovered) fields based on those that have already been found. The technique is based on the inference that the full, naturally occurring population of petroleum fields in a region will have a log-normal distribution.

A third method describes “creaming” curves, with the premise that the biggest fields are found early in the exploration cycle and smaller fields will only be found subsequently.

The only place in New Zealand where statistical analysis has been attempted is Taranaki Basin but, even here, a lot more drilling is required before statistically-based predictions of future field sizes are likely to be valid. Early predictions of future discoveries turned out to be too pessimistic, but were based on a very sparse data set.

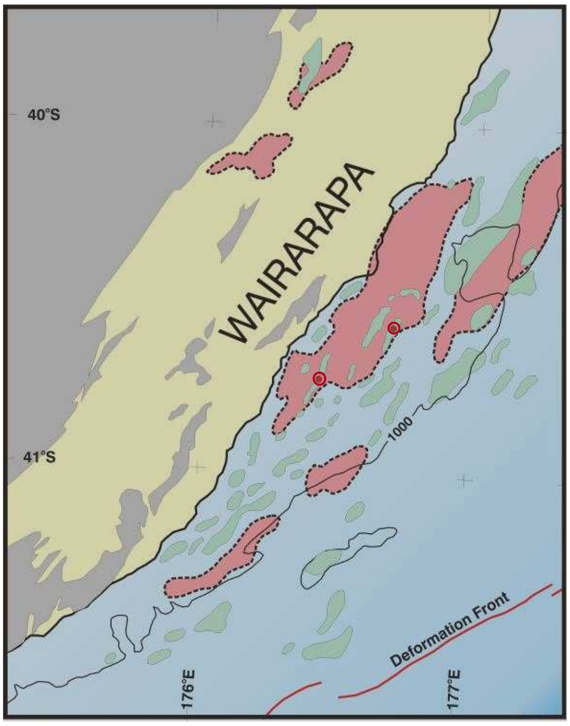
At present, total Taranaki petroleum reserves discovered so far are roughly 1,900 millions of barrels of oil equivalent (mmboe – approximately 11,628 PJ). Since the initial discoveries of Kapuni (1959) and Maui (1979), this total reserves inventory has been built up by punctuated, but steady, incremental additions. Based on the number of discoveries and cumulative reserve additions in recent years, one might predict that the next ten discoveries in Taranaki Basin would add about 300 mmboe (1,836 PJ) in new reserves volumes. This assumes that exploration maturity has not yet reached the point of diminishing returns. Indeed, it also doesn’t allow for radical geological paradigm shifts, technological advances, or drilling in the deep-water Taranaki Basin, all of which might result in one or more very large fields being found.

The most comprehensive quantification of possible future field sizes is based on detailed interpretation of seismic reflection profiles and derivative subsurface mapping of undrilled structures and stratigraphic traps. The result is the delineation of “leads” (trapping closures that are roughly defined with sparse data) and “prospects” (trapping closures that are relatively well defined with adequate data). An example of a lead and prospect map is given in Figure 4.2.12. Prospect mapping and evaluation is very time consuming. Companies generally only undertake this work within their exploration licence blocks and only to prioritise one or two prospects to drill. Even then, the predicted (pre-drill) volumes are fraught with assumptions and, time and again, have proved to be overly optimistic.

Figure 4.2.12 – Mapped structures in the onshore and offshore Wairarapa

Structural anticlines (green) and areas of source rock "kitchen" (red)

The red dots represent the location of two wildcat exploration wells.



The amount of oil or gas in any individual structure, assuming adequate "charge" from source kitchens and effective sealing of cap rocks, depends primarily on the overall size of the structure and the thickness and quality of the reservoir. Theoretically, a structure that measures 100 km² in area, with a net reservoir thickness of 10 meters and a porosity of 10%, has a potential volume of 100 million m^3, or 630 million barrels, in place. With a recovery factor of 10%, the reserves of such a structure would be nominally 63 million barrels.

There is no inventory map or comprehensive compilation of undrilled prospects in New Zealand. A few maps of undrilled structural closures, primarily within the Taranaki Basin, are available in government archives, having been lodged by companies upon the relinquishment of their exploration licence areas. The original maps of these prospects have not been verified since that time, and neither have the assumptions used for quantifying volumes of hydrocarbons within these structures. GNS Science has also created prospect maps for areas such as the deep-water Taranaki Basin, offshore Northland, and East Coast North Island (e.g. Figure 4.2.12).

4.2.2.2.3. Regional prospectivity

Taranaki Basin continues to be the focus for exploration in New Zealand, but other regions are also receiving attention. In the far, offshore, deep-water Taranaki Basin, and all other New Zealand basins, there are genuinely perceived geological prospects. Some significant, but uneconomic, discoveries have already been made that prove the existence of viable petroleum systems in other basins. In Canterbury, the Galleon-1 well produced a respectable 10 million standard cubic feet of gas per day (mmscf/day) and 2,300 barrels of condensate per day on test.

There are plenty of structures present in New Zealand’s frontier basins that are potentially large enough to meet economic thresholds at current oil prices, or perhaps even lower prices. As an example, the operator of a deep-water licence in offshore Canterbury Basin has recently identified some structures that could contain 100 million-plus barrels of oil or several trillion cubic feet of gas. Two of these are now mature (drillable) prospects and one has a huge mapped closure of 200 square kilometres.

However, most structures identified in our offshore regions are still delineated as “leads”. Considerably more seismic data acquisition and mapping is needed to confirm their presence and to convert them to “drillable prospect” status.

4.2.2.2.4. Recent success rates

In the calendar years 2000 to 2005, a total of 149 wells were drilled, 69 of which were in the latter two years. Of the wells drilled, 74 were “wildcats”, away from established fields. Twelve new discoveries were made, giving a statistical success rate of about 16%, or around one discovery per 6 wells [MED (2006)]. In this day and age, in which new discoveries are hard to come by globally, this is a very acceptable return. Even more significant is that, out of the nine wildcat wells drilled offshore in Taranaki during the 2000 – 2005 period, six were commercial discoveries. This bodes well for offshore exploration elsewhere in New Zealand.

4.2.3 Barriers and limitations

With overwhelming world demand, the only barriers to finding and developing oil fields in New Zealand are financial - in particular whether the size (and location) of the discovery merits its development.

In order to produce marketable fuels, crude oil must be delivered to a refinery. The subsequent value of the products depends on the complexity of the refinery. Simple refineries can only produce basic products. The route to upgrading bunker fuel or furnace oil into higher-value products is achieved by adding refining complexity e.g. crackers and cokers. New Zealand has a state-of-the-art refinery based on hydrocracker technology and is, therefore, able to process heavy and sour crudes and extract more value from the “bottom of the barrel”.

4.2.4 Introduction to conversion technology

The main technologies that combine together in order to realise the potential of subterranean oil resources are described under the following classifications:

- Oil extraction facilities
- Oil production facilities
- Transportation of oil
- Oil refining

4.2.4.1 Oil extraction facilities

The safe extraction of petroleum fluids from within the earth's crust to the surface for processing requires significant engineering in order to address the risks associated with high pressure, high temperature and risk of combustion. Drilling into reservoirs requires the capacity to accurately target drilling locations several kilometres away (through rock) from the drilling rig, all this whilst controlling the risks of pressure / temperature blowout etc. The high costs of drilling compounded by the risk that the target is 'dry' or has 'low flow rates', makes this a high cost / high risk venture.

Drilling technology is a mature industry but recent advances in down-hole tools and the capacity to 'deviate' (i.e. change the direction) of drilling has supported a significant improvement in field productivity. The capacity to drill 'deviated' wells enables the production of near shore reservoirs to be processed onshore, with significant associated advantages.

When fluids are removed, the reservoir pressure will drop unless the volume is replaced. Oil reservoirs with a gas cap can often maintain their wellhead pressure for a long time, because the gas expands to fill the volume. Other reservoirs require the 'natural drive' of the surrounding water column to infiltrate. If the edges of the reservoir have limited porosity, then the reservoir will have little 'natural drive', and may require artificial lifting (jet pumps, gas lift, or other methods), or gas re-injection, to bring fluids to the surface. Water injection and steam heating technology has not been used in New Zealand, though both techniques are common overseas, and can be considered as a useful tool for secondary or enhanced oil recovery.

4.2.4.2 Oil production facilities

Oil production facilities treat wellhead fluids, which often contain a mixture of oil, water, gas and impurities, and render them suitable for sale or for onward transmission for further downstream processing. The primary separation step generally involves de-sanding (i.e. removal of solids) and initial separation of liquid phases from the gas phase. Later steps separate water and waxy emulsion phases from the oil phase. The separation of water and waxy emulsion phases is generally based on settling by density difference, but may also use heat and surfactants to speed up the separation. Any pressure reduction and heating that occurs in the later steps will also yield gas that is captured and processed.

Depending on the type of reservoir, it's history and source rocks, the oil products that are extracted can be quite different. Many rich gas fields produce either very light oils (i.e. condensate) as well as light petroleum gas (see LPG in gas section). Oil crude is typically characterised by density and waxiness, with light (i.e. lower density) oils having lower viscosity and boiling point, whilst heavy crudes having higher viscosity and boiling point. Many New Zealand crudes are solid at room temperature, due to high wax content, yet are "light", and therefore sell with a price premium (e.g. Tapis light). Depending on the crude, it may be commercially attractive to separate a particular fraction of the oil phase for direct sale (e.g. Naptha from Maui). These crude oil fractions can be extracted by distillation (see oil refining).

Offshore production facilities are either floating or fixed. The most commonly adopted floating facilities consist of a tethered FPSO (Floating, production, storage and offloading) vessel from which shuttle tankers periodically load oil. Three have been installed in New Zealand.

- The Wakaaropai - a second-hand converted tanker which was installed in 1996. The FPSO operated on the Maui field for about 10 years.
- The Umaroa – an oil tanker that was converted to FPSO operation in 2006, and now services the Tui field development.
- The Raroa – a converted oil tanker which now services the Maari field.

Figure 4.2.13 – "Umaroa", the Tui field FPSO

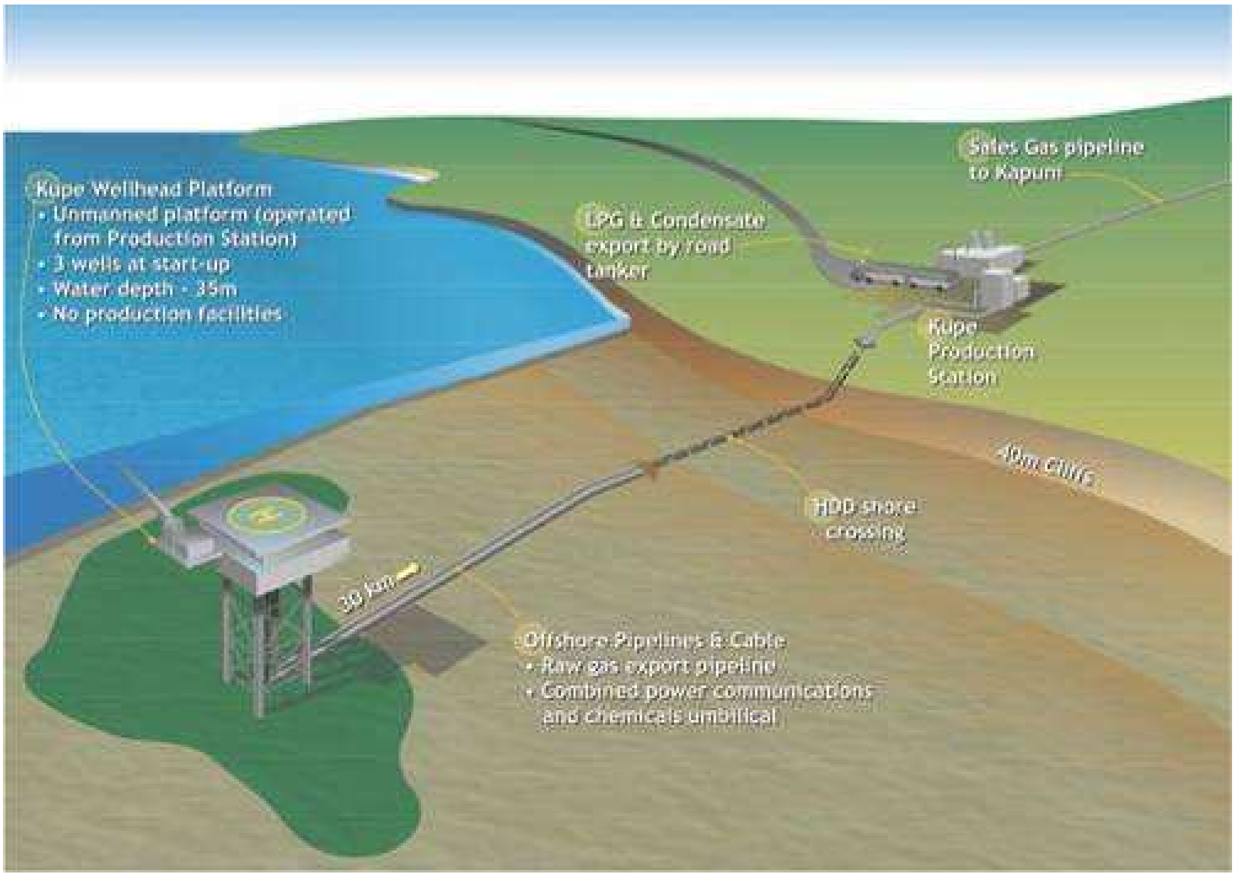
Source: http://www.nzog.com/gallery

Fixed offshore production facilities consist of topsides and support structure (i.e. jacket). The design and cost of offshore production facilities in New Zealand are controlled by three main factors:

1. Weight of the "topsides" processing plant - The weight and, hence, the cost of the topsides is primarily determined by the oil throughput volumes, with processing complexity a further factor.
2. The water depth - The weight and cost of the support structure is principally determined by the water depth and with topsides weight being an important secondary factor.
3. Mobilising offshore work barges - This factor particularly applies to remote regions, like New Zealand where the price tag for barge mobilisation is in the range of US$20 – 25 million. There is ample incentive for inventive solutions that avoid a work barge. Some are based on utilising the drilling rig - which must be mobilised anyway.

A significant portion of the areal footprint of oil production assets is associated with the storage of resulting products – in the case of oil and condensate, these are large tanks.

Figure 4.2.14 – Schematic of Kupe development



Source:http://www.pesa.com.au/publications/pesa_news/feb_mar_08/pesanews_9204.html

The large “jack–up” rigs that are needed for work in New Zealand waters can lift weights in the range of 300 – 400 tonnes. Small oil discoveries in relatively shallow waters can be designed so that both jacket and topsides weights arebelow this lifting weight limit. Both the Pohokura and Kupe offshore facilities were designed for jack-up installation.

Figure 4.2.15 – The “jack-up” used for the Kupe development, lowering the wellhead platform jacket

Source: http://www.nzog.com/gallery

Current production facility designs favour maximum transfer of processing from offshore to onshore with offshore facilities designed primarily to render the wellhead fluids suitable for pipeline transport. When it is possible to use onshore processing, low weight topside (with reduced levels of manning) can be designed.

While wellheads and production sites need to be located adjacent to their petroleum reserves, there is more flexibility possible when it comes to locating onshore oil / gas production facilities. Sites are chosen with a variety of outcomes in mind e.g. proximity to existing infrastructure (roads and pipelines), general site suitability, minimisation of damage to the environment and impact on the local community.

Over recent years there has been a concerted effort to reduce the cost of offshore production facilities. This has resulted in a major rethink on all aspects of offshore processing and manning, with the result that every effort is now made to transfer as many operations as possible from offshore to onshore. As a consequence, many offshore platforms are now little better than wellhead or drilling / work-over platforms, and designed for minimal or intermittent manning at the most. It has been oil industry practice to minimise processing at oil / gas production plants and concentrate such operations at a refinery. Consequently oil is only processed sufficiently to allow trans-shipment to a refinery - whether by pipeline or by sea-going tanker.

Once the more accessible oil fields are depleted, attention turns to those located in deeper water and more hostile environments. While New Zealand does not yet have deep water producing fields, these are not uncommon overseas, and it is a just a matter of time before such developments are proposed here.

Too date, all of New Zealand's oil processing infrastructure has been built in Taranaki and surrounding waters. The scale of this infrastructure ranges from very large (e.g. Maui) to very small (e.g. Kaimiro).

4.2.4.3 Transportation of oil

Stabilised crude oil can be transported to refining facilities with shipping vessels, underground / undersea pipelines, and trucks. The selection of transport technology is mostly determined by location, distance to destination and volume. Shipping is the most appropriate technology for the movement of crude over long distances by sea e.g. from a deep offshore production platform to foreign market. Pipelines generally service offshore platforms that are reasonably close to shore / oil refinery. Offshore (i.e. sea floor) pipelines are considerably more expensive to install than onshore pipelines. This technology provides a clean, efficient mechanism for moving a large to moderate volume of liquids. For very small fields, where it can be difficult to justify the investment in pipelines, the use of trucks is appropriate.

4.2.4.4 Oil refining

The technology to refine oil, gas and condensate has undergone well over one hundred years of continuous development and, hence, can be considered mature. In the early years, the principal uses for oil were for lighting (kerosene lamps), heating (fuel oil), and lubricants. The advent of the internal combustion engine and mass production established a market for motor spirit (i.e. gasoline, petrol, diesel). All of these products are particular fractions of crude oil and can be extracted by distillation (i.e. separation by difference in boiling point). Further improvements to the quality of fuels are achieved by removing contaminants (e.g. sulphur), and by adding additives (e.g. pour point suppressant, high octane reformate / alkylate / isomerate).

The refineries that convert crude into consumer products are highly complex and interlinked plants which rely on scale and highly specialised technologies (e.g. catalysts, membranes) in order to remain cost effective. Most of the light ends (e.g. butanes) are converted in octane enhancers, whilst the heavy ends can be cracked to yield more pentanes, hexanes, heptanes and octanes for transport fuels, or further refined to yield lubricants / waxes and bitumen. Excess light ends and heavy ends can be exported as low value products, but are generally used by the refinery and associated companies for heating (i.e. fuel gas and fuel oil).

New Zealand's only oil refinery is located at Marsden Point, Northland. This refinery employs deep hydro-cracking technology to upgrade imported heavy end processed crude oil to transport fuels. More details regarding this refinery and associated technology can be found in Section 6 – Secondary conversion.

4.2.4.5 Environmental and social aspects

Oil and gas facilities have to comply with the RMA, and all other national and local regulations. To date it has not been difficult to obtain the necessary consents to build and operate them. Consents cover noise and effluents and usually include requirements in regard to abandonment and clean up, once the plant has come to the end of its useful life. Drilling and well-head sites are relatively small, and generally not particularly obtrusive in the landscape. Oil / gas / condensate processing plants are much larger, but, to date, finding suitable sites has not proved difficult. Facilities are needed to avoid spills and pollution, contain and clean up contaminated storm water, minimise noise and flaring. Flaring is only permitted to prove the viability of reserves, and during any short-term emergencies.

4.2.4.6 Technology forecast

Looking ahead, there is an expectation of continued improvement - particularly in the area of energy efficiency. Such refinements are likely to be incremental rather than major innovations e.g. improvement in catalyst conversion efficiency.

In New Zealand, the existing oil and gas production facilities were all designed and built using the best technology that was available at the time and, in most cases, the plants have been upgraded in line with current world best-practice. As New Zealand has access to the same worldwide process technology as is available elsewhere, there are few differences, if any, between our gas processing / refining facilities and those performing similar functions overseas. In the absence of significant new capital investment, this technology is unlikely to witness major changes.

4.2.5 Asset characterisation

The cost of developing oil assets varies considerably in response to: field risk, field location, reservoir quality and size, the envisaged production time frame etc. Furthermore the global oil service sector often experiences cyclical boom and bust periods. This leads to periodic inflation and deflation in the cost of oil development services and equipment. A prime example of this cycle was the rapid price inflation experienced within the sector from 2003 to mid 2008 followed by the rapid collapse of prices analogous to the decline in the price of crude oil in the second half of 2008.

4.2.5.1 Oil extraction facilities

The cost of oil extraction facilities is relatively trivial compared to the cost of exploration and drilling. The costs of these facilities have either been lumped with the oil production facilities or are a small fraction of the production facility costs – see Table 4.2.16.

The timeframes for developing oil extraction facilities is similar to the production facilities, but the exploration and research phases are generally in excess of five years. As it can take seven years between a wildcat discovery and eventual production, there is a political element in maintaining a climate that stimulates further exploration.

Every oil field discovery has a finite life and the summation of the cumulative production profiles of all discoveries defines the variability in supply. Production from a new discovery tends to increase fairly rapidly, initially, as multiple wells are drilled. Production then plateaus for several years before, eventually, declining both in quantity and pressure.

During the exploration phase, the risk that an asset is not further developed is very high since test drilling very often (typically 7 out of 8 times) fails to find a reservoir that is sufficiently large / productive to justify commercial development. Once a well has been successfully tested, the risk of the asset not being developed is relatively minor.

Historically, the fluids extracted from test wells were flared / burnt, with subsequent GHG emissions. Increasingly the fluids extracted during exploration are recovered. Once a well is in production, the only GHG emissions are those associated with leaks and emergency flaring. These ‘fugitive’ emissions are generally less than a few percent of the production rate.

4.2.5.2 Oil production facilities

In the context of the oil and gas sector, oil production facilities tend be fairly simple, with costs dominated by settling and storage tanks. The classic way of benchmarking the cost of oil production facilities is to consider CAPEX in terms of "total recoverable" reserves. Typical worldwide benchmarks for the cost of different types of oil production assets are summarised below. Onshore production facilities are generally the easiest and cheapest to construct, whilst offshore production facilities must either be supported on a structure or floated (often on a ship), hence costs are significantly higher.

Table 4.2.16 – Typical benchmarks for costing oil production assets

Description	Drillex US$/boe	CAPEX US$/boe (reserves)	OPEX US$/boe
Onshore production plant	2 to 5	2 to 3	5 to 7
Wellhead platform (<30m water) Production platform (<30m water) Deep water	2.5 to 5 + Rig mob/demob 2.5 to 5 + Rig mob/demob No data	NZ$50 million 3 to 5 + Barge mob/ demob No data	6 to 8
FPSO with subsea tie-ins*	7 to 9	5 to 7	6 to 8

* - Assuming FPSO ownership rather than leasing.

Since New Zealand has relatively few production facilities, it has been possible to obtain actual construction costs (or cost estimates) for the majority of assets.

Table 4.2.17 – Capital cost of New Zealand oil production assets

Asset	Commission date	Capital cost (NZ$ million, 2007)	Comment
Moturoa	1886	Unknown	Abandoned
New Plymouth Condensate, MeOH, Crude tanks	1970/80s	180	
McKee field	1984	30	
Waihapa field	1986	50	
Maui B FPSO (Wakaaropai)	1996	170	Sold
Minor fields - TAWN, Kaimiro, Ngatoro, Cardiff etc.	1999	80	
Cheal	2007	30	
Tui drillex (incl. completions) Tui FPSO (Umaroa)	2007 2007	400 320	 Leased FPSO
Maari FPSO (Raroa)	2008/9	550	

The timescale to build a production facility depends on the size and complexity, but three to five years is typical. Bringing offshore discoveries into production takes a year or two longer. The following times are typical timescale scales for various phases of project development:

i) Option elimination, and definition of preferred development plan: 18 months
ii) Consents: approx 12-18 months, partly concurrent with i) above
iii) Design and procurement: 12-18 months, partly concurrent with ii) above
iv) Construction: 18-24 months, partly concurrent with iii) above

The field life of oil reserves is dependent on the size of the discovery and rate of extraction. Generally the supporting infrastructure is designed for a life of between 25 and 30 years, with major overhauls after about 10 years. The constant process of plant renewal and modifications means that in reality many plants can have a life in excess of 30 years. Smaller fields are often produced over a short time frame (e.g. less than 10 years) in order to rapidly recover capital investment, and reinvest. The physical infrastructure associated with such assets is often designed so that it can be re-deployed / moved to other small fields.

4.2.5.3 Oil transport assets

The primary mechanism for transporting oil is via pipelines. In order to obtain a first pass, "high-level" order of cost for such pipelines, the following simple formula is often applied.

$$\text{Installed pipeline cost} = (L \times D \times m) + X + V + M$$

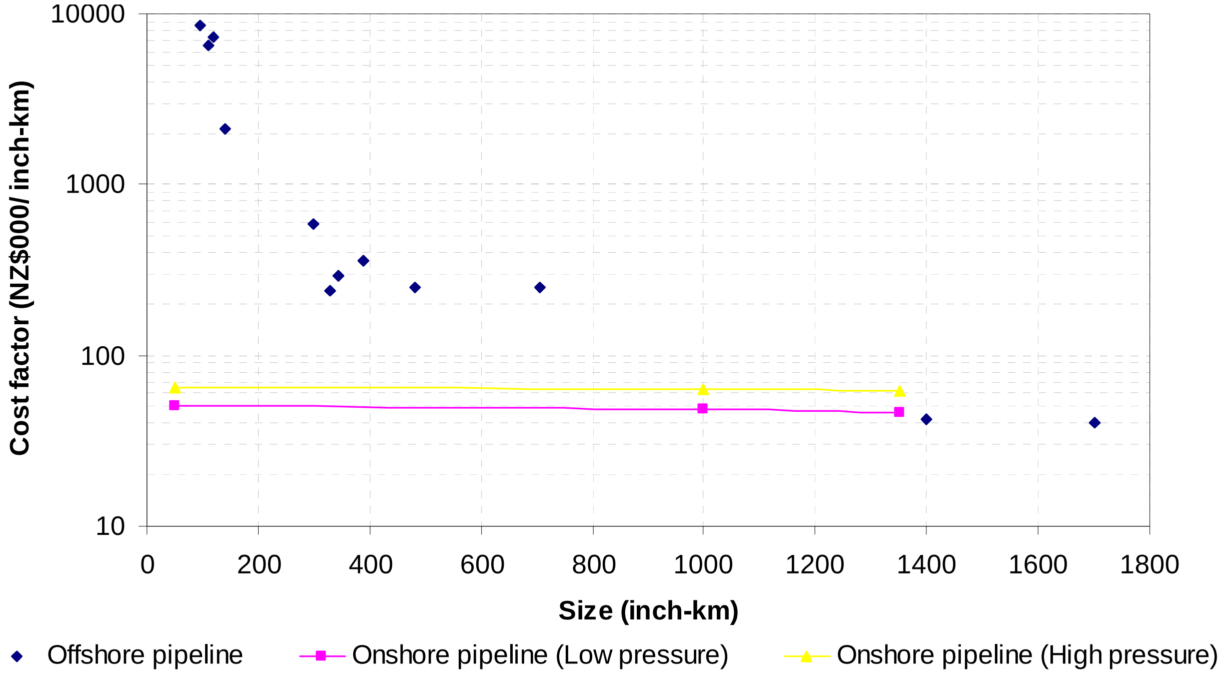
Where:

- L = pipe-line length in km
- D = pipe diameter in inches
- m = is a pipe length-diameter cost factor (see Figure 4.2.18)
- X = fixed NZ$ cost per crossing
- V = fixed NZ$ cost per valve stations
- M = Pipe-lay barge mobilisation cost (for offshore pipelines)

This formula is reasonably applicable for carbon steel pipelines in the size range of 4" – 16", which traverse relatively easy open terrain. The formula allows for consents, easements, materials, construction plant and labour, engineering design and supervision. Higher pipeline cost factors should be applied to pipeline laid in difficult (steep and rugged) terrain, and for pipelines constructed from exotic materials.

The costing of onshore pipelines is relatively straight forward application of the pipeline cost factors summarised in Figure 4.2.18. The cost of crossings can vary from, approximately; $10,000 for crossing a rural road; $25,000 for crossing a creek; up to $250,000 for crossing rivers or major obstacles. Any horizontal directional drilling or valve stations need to be costed separately, as these can vary considerably depending on terrain and line size.

Figure 4.2.18 – Pipeline cost factor (NZ dollars, 2007)



The cost of offshore pipelines can be estimated using the above formula, but since New Zealand's our meteorological-oceanic conditions are onerous, construction costs can be significantly higher than predicted by the simple formula. For offshore pipelines it is also necessary to determine pipe-lay mobilisation costs. There are basically three options:

1. Conventional pipe-lay barge mobilisation – Often in the order of $20 – 30 million. Currently worldwide supply of these barges is tight.
2. Modified light vessels to commission bottom tow or flexible / reeled pipeline designs. This option can be attractive because it obviates conventional barge mobilisation costs.
3. Work barge mobilisation - For some offshore jobs where heavy platforms and topsides need a work barge, the mobilisation costs can be spread over both conventional work and pipe-laying.

Smaller fields may deploy tankers to transport stabilised oil, the distance of transport and the pour point[5] of the oil are the key factors affecting cost. For oils with a high pour point the trailers may need to be insulated and / or heated. The cost of trucking is typically between $0.1 and $0.2 per tonne-kilometre.

[5] It is a rough indication of the lowest temperature at which oil is readily pumpable.

4.2.6 Research status

“Applied research” that furthers the understanding of New Zealand’s petroleum potential and develops a broad nationwide inventory of petroleum prospecting leads and concepts, has the potential to increase petroleum exploration and subsequent improvement in national trade position. This type of research is beyond the mandate of private companies, who are focused on detailed mapping of their licence areas, and consequently must be undertaken by governments or national petroleum companies. New Zealand’s understanding of petroleum potential is relatively immature, hence there are several research areas which should be considered:

1. Undertaking sediment and structure mapping of frontier regions - the cost of this data acquisition and interpretation is non-trivial (of at least $10 million per annum for at least a decade).
2. "Next generation" regional digital maps of basin depositional systems and structures using industry-standard state-of-the-art techniques. To “fast-track” the digital mapping of say 5 basins over the next 10 years would require about $2.5 million per annum.
3. Aggregation of exploration leads and prospects. The Crown Minerals archives contain an enormous amount of historic exploration and leads data from oil company mapping of licence areas. Significant value could be derived from systematic nation-wide compilation of the relevant ‘open file’ data.
4. Developing innovative exploration play concepts, including for deep gas and stratigraphic traps which could be very big but which have hitherto received little attention.

New Zealand contributes little to the development of oil and gas technology advances but can still benefit from changes as they occur. For example, advances in sub-surface imaging and computer technology has enabled exploration in new areas in deeper water. The advent of “geo-steering” and horizontal drilling has allowed production wells to penetrate much more of the reservoir target, thus enhancing ultimate recovery. The uptake of other technology, such as the use of floating production, storage and off-take vessels and seabed completions, has facilitated development of offshore oil fields without the need for pipelines to shore-based production stations.

Because petroleum field research, exploration, discovery, and production processes all have long lead times, there is value in maintaining (or accelerating) research momentum. Without meaningful petroleum systems modelling, visualisation and leads, the prospect for rapidly increasing national oil field exploration and development will take longer.

The national benefit that results from petroleum exploration and development is set by the associated rules and regulations. In order to ensure that the nation derives maximum benefits from such developments, there is a need for strategic analysis of national policy and strategy. The review should consider:

- The impact of environmental taxes on trading relations e.g. carbon tax on imported products.

- The economic impact of paying a premium for domestic fuels relative to imported fuels - Money spent domestically has significant kick-on effects associated with provision of services and reduced sensitivity to the dollar market.
- The benefits of a national oil company and / or stronger regulation - as the value of oil increases, and competition for drilling ships / capital investment increases, many nations are nationalising their petroleum assets. In this way nations can control the rate of development of assets, and realise the full value of assets, rather than just the royalties.
- The benefits of stronger regulation e.g. maximum percent of foreign ownership, minimum percent of New Zealand construction content.
- The role of demand side management and urban form planning – reduced petroleum consumption could potentially have greater benefit than resource development.
- The importance of national dialogue and acceptance of resource exploitation strategy, with particular focus of the role of revenue reinvestment.

Table 4.2.19 – Research status

(Green highlight indicates 'Fair knowledge', Amber indicates 'Could improve', Red indicates 'Knowledge gap exists')

	International	New Zealand	Comment
Develop a strategic picture to assess risks / responses to volatility in oil availability / affordability, and economic impact of indigenous production Vs import.	Advancing Government bodies	Immature MED, Treasury, Consultants	There have suggestions that a "Petroleum strategy development" advisory board be established with a mandate similar to the former "Liquid Fuels Trust Board".
Education and understanding regarding oil substitution	Advancing IEA	Immature GNS, CAENZ, NIWA, Solid Energy	Coal to liquids, Gas to liquids, Biomass to liquids, CNG and urban form all provide pathways for oil substitution.
Quantification and qualification of basin structure, volumes and type of sediments and assessment of petroleum prospectivity in far offshore frontier areas	Advancing. Petroleum industry. Other Government agencies such as CSIRO, AGSO, USGS	Immature GNS, Crown Minerals	Acquisition and interpretation of offshore geophysical and remote sensing data to identify possible petroleum exploration plays. Primarily seismic reflection data, but also including gravity, magnetic, and geochemical sniffer surveys.
Quantification and qualification of structure and volumes and type of sediments in proximal frontier basins with known but as yet uneconomic petroleum potential (i.e. excluding Taranaki Basin)	Advancing. Petroleum industry. Other Government agencies such as CSIRO, GA, USGS	Advancing. GNS, Crown Minerals	"Next generation" state-of-the-art digital mapping of basin depositional systems and structure from seismic reflection data, for input into sophisticated models of petroleum generation, migration and likely present-day habitats.

Aggregation of existing un-drilled exploration leads & prospects and identification of new potential targets	Advancing, Petroleum industry Other Government agencies such as CSIRO, GA, USGS	Immature. Crown Minerals, GNS	Compilation of un-drilled leads and prospects previously mapped by oil companies, with associated metadata, supporting information and verification, including names, location, target horizons and estimated reserves volumes. Also new independent systematic basin by basin mapping of extra prospects and leads. Development of innovative exploration play concepts, including for deep gas and stratigraphic traps, and petroleum charge scenarios.
Maximising production from discovered fields (recovery efficiency)	Advancing, Petroleum industry, Other Government agencies such as CSIRO	Advancing. GNS, UoA	Applied reservoir quality characterisation through petrology, petrography, diagenesis, rock property and stratigraphic architecture studies, for input into production simulation models.
Petroleum systems geoscience	Advancing, Petroleum industry, Other Government agencies such as CSIRO, GA, USGS	Advancing. GNS	Increasingly specialised determination of geological factors that are critical for petroleum charge, re-migration and accumulation. Some data shortfalls include: seal rock properties, structural controls on fluid migration, geochemical correlations between source rocks and produced oils, empirical reservoir properties, controls on reservoir quality by depth, area and geological formation, analysis of paleo-oil accumulations, effects of tectonics on subsurface stress and fluid pressures.
Petroleum geoscience databases	Advancing, Petroleum industry	Advancing. Crown Minerals, GNS	Sophisticated data compilation and interpretation products, and digital data delivery mechanisms, especially in GIS (map-referenced) format. There is exciting potential also for presenting data in 3D visualisation models.
Drilling	Mature	Immature. Oil industry	Drilling many wells is the number one requisite to make new discoveries, but drilling research per se is not required.

Processing technology	Mature. UOP	Mature. NZRC, Transfield Worley	R&D is being done internationally.
Petroleum price forecasting	Immature	Immature. MED, NIWA, Solid Energy	'Active following' requires an annual budget to be allocated to the task.

4.2.7 Summary

New Zealand has adopted an 'open market' economy which utilises trade export in products of comparative advantage e.g. dairy and forestry, to offset the costs of imports e.g. oil and vehicles. This approach exposes the economy to vagaries of world oil price – if the world oil price increases significantly faster than the value of export products, the country' trade balance would be severely impacted. In world terms, New Zealand has high oil demand and low indigenous oil production, consequently our economy would most likely be more vulnerable to oil price / supply volatility than most of our competitors.

Currently, New Zealand's energy and economic policies treat the threat of 'peak oil' as being sufficiently distant or low impact, as to not warrant any significant change in short term strategy. Currently, the government supports exploration and development of petroleum resources. There are a great many research opportunities which could support this aspiration, most of which pertain to modelling, mapping and acquiring data about prospective basins. Such research should be linked in with research that assesses the impact of rules and regulation associated with such development. Obtaining sound forecasts regarding oil supply and pricing can be a very difficult and vexing task for economic planners, but the magnitude of the possible impact justifies the effort. The physical principles and limits must be held constantly in mind so as to avoid being mis-lead by lobby groups[6] and vested interest groups.

To increase national resilience to oil supply – demand tensions, New Zealand must either increase indigenous oil production or constrain the demand for oil. New Zealand has reason to be optimistic about its oil future, since it has vast, relatively unexplored, offshore territories within which there remains considerable potential for world-class oil fields to be found. Managing the demand for oil, is a strategy that is complementary with reducing greenhouse gas emissions, but is currently only meeting with minor success.

Ultimately, New Zealand's strategic approach must remain cognisant of the long lead times associated with petroleum field research, exploration, discovery, and production processes. Maintaining underlying economic prosperity will require continued research, support and reinvestment of revenue streams. Making a step change in economic performance or responding to the threat of supply – demand tension will likely require government intervention and more regulation in the domestic petroleum market.

[6] See Naomi Orekes "Merchants of Doubt" - http://scienceblogs.com/deltoid/2010/03/naomi_oreskes_on_merchants_of.php

Section 4.3
Unconventional oil

4.3 UNCONVENTIONAL OIL RESOURCES

4.3.1 General introduction

Differentiation between conventional and unconventional oil resources is notoriously difficult. For this project we define ‘conventional oil” as any oil that can be extracted as a free flowing liquid from the reservoir rock either onshore and or in offshore waters. In this section we consider:

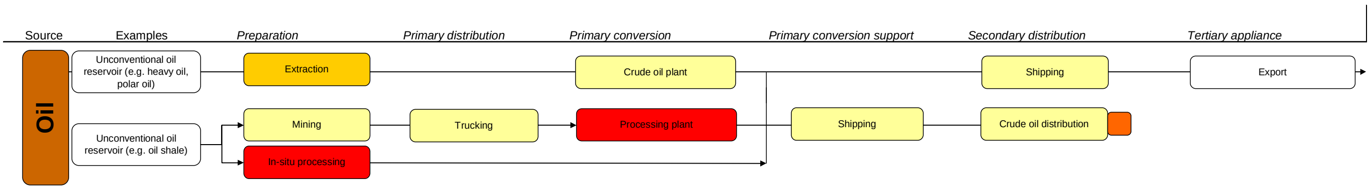
- Polar oil
- Heavy and extra heavy oil
- Shale oil
- Oil from tar sands

Unconventional oil resources can be characterised by:

- Best resource is currently fractured shale ‘sweet spots”.
- Significant technical, financial and environmental risk.

It should be noted that deep water oil production is considered to be conventional production by our definition (i.e. is considered in Section 4.2) despite some classification systems considering theses liquids as unconventional resources.

Figure 4.3.1 – Unconventional oil production and utilization pathways



A full view of the pathway is presented in the Pathway Overview Map at the start of this document.

Although New Zealand has proven unconventional oil resources, no unconventional oil is currently produced. Developing these resources is considered to have numerous technical, environmental and financial risks which, considering New Zealand promising conventional oil prospects, leads to the conclusion that unconventional oil production will not commence in New Zealand in the next few decades.

4.3.1.1 Myth busting

Since unconventional oil is often perceived as the new frontier and a solution to declining conventional oil resources, a great many myths exist.

Perhaps the most significant and dangerous myth is in regard to the size of unconventional oil resources and the potential contribution to the world oil supply. It is true that the known reserves of unconventional oil resources are vast, in fact many times greater than the known reserves of conventional oil. This has led many people to conclude that one day, unconventional oil will supply the majority of the world's oil needs, and issues such as global peak oil will have little impact on oil prices and consumption patterns. This argument fails to recognise that the peak oil problem stems from insufficient production rates rather than insufficient reserves. Unconventional oil resources, albeit having an enormous resource base, have notoriously low production rates, which are very difficult to increase in the short term. A study by Kjell Aleklett (2007) demonstrated that even a government backed crash program for the Athabasca tar sands (one of the world's most prolific sources of unconventional oil) would be unable to compensate for the depletion projected for the conventional oil provinces of Canada and the North Sea over the next 20 years. In summary, the production rates of unconventional oil are very unlikely to offset the observed decline in conventional oil production.

Since unconventional oil production rates are likely to remain low compared with conventional oil production rates, this production will have little impact on world oil prices, oil consumption patterns, and geopolitical interactions between oil exporting and oil consuming countries.

4.3.2 Introduction to resources

Polar oil is generally termed unconventional not due to reservoir characteristics, but mainly due to the location of the resource in some of the remotest and climatically harshest regions of the planet. Since these factors make oil extraction in polar regions very expensive, developments have so far been restricted to very large / easily targeted reservoirs. Examples of polar oil development include Alaska's north slope, and the Yamal peninsula in Russia (which is gas prone). Recent oil price increases have renewed intrest in polar oil, with numerous new polar oil projects being proposed for: ANWR (Alaska National Wildlife Refuge), Norway's offshore polar regions, the Barents Sea, Far East Siberia and offshore Greenland. No polar oil developments exist or have been proposed in the southern hemisphere. New Zealand has a claim[7] to parts of Antarctica which may potentially yield polar oil. From a geological point of view Antarctica is utterly under-explored in regards to oil and gas, and the Protocol on Environmental Protection to the Antarctic Treaty (1991) prevents such undertakings. The limitations of this treaty expire in 2048, which may trigger renewed international interest in, and competition for, the continent's potential mineral resources, probably similar to the conflicts over Arctic resources seen in recent years.

Heavy and extra heavy oil deposits have been formed analogous to conventional oil deposits in the geological past. However, as implied by the name, these oils are denser and much more viscous than conventional crude. One common definition categorizes crudes with an API gravity of less than 20° (specific gravity greater than 0.933 kg/L) as heavy oil. Heavy oils generally consist of a blend of longer chained hydrocarbons with lower hydrogen content than conventional crudes. This is often a result of many heavy crudes being subject to biochemical degradation, reducing the fraction of shorter chained and more volatile hydrocarbons. Heavy and extra heavy oils often contain higher concentrations of sulphur, waxy components and other contaminants than

[7] Several related agreements termed the Antarctic Treaty System, 1959.

conventional crudes. Heavy crudes are generally found in shallower reservoirs than conventional oil, however this advantage has to be balanced against much higher production and refining costs and extraction efforts for heavy oils. Furthermore, individual flow rates of heavy oil wells are much lower than for many conventional oil developments, which is a limiting factor in regards to the development times required for heavy oil projects. Prolific heavy oil deposits exist in Venezuela, the US, Canada and the Middle East, however at this point in time no information indicates the existence of heavy or extra heavy oil deposits in New Zealand or in off shore waters.

Definition boundaries between extra heavy oil and tar sands are not clear cut. In general tar sands are defined as heavy oil deposits where the crude oil present is not found as a free flowing liquid at given reservoir conditions. Petroleum found in tar sand deposits often incorporates many of the unfavourable characteristics of heavy oil (e.g. high viscosity, high sulfur and low hydrogen content). Like heavy oil reservoirs, tar sand deposits are usually shallow, with most extraction activity focusing on near surface deposits, where open cast mining methods can be employed for extraction. The majority of tar sand exploitation is currently centered around deposits in western Canada, but other deposits of this unconventional oil have been identified in the US and Latin America. To this day no information indicates the existence of tar sand deposits in New Zealand.

Oil shale deposits are an immature form of petroleum. In general oil shale deposits are accumulations of petroleum source rocks that were either not buried or not buried deep enough to be subjected to high enough temperatures and pressures required for the formation of petroleum from organic material contained in the source rock. Consequently the petroleum resource has not had the opportunity to migrate from the source rocks into reservoir rocks. Oil shale deposits are wide spread around the world, with particularly large deposits in the Midwest US. The petroleum resources contained in oil shales are several times larger than all known conventional oil deposits. New Zealand has confirmed deposits of oil shale, both in the South Island (e.g. Nevis Valley) and the North Island (e.g. Gisborne / Hawkes Bay). A number of smaller oil companies (e.g. Xtract Energy Plc) have obtained exploration licences from Crown Minerals for parts of these resources, and are at various stages of exploration and resource assessment.

Fractured shale ‘sweet spots” represent locations within classic shale oil deposits where in the geologic past there was sufficient heat and pressure to transform some of the organic content of the shale rock into crude oil. Because this oil has not migrated to a reservoir rock, we classifiy it unconventional petroleum. Trans-Orient Petroleum is conducting a drilling campaign in the Gisborne / Hawkes Bay region (The Gisborne Herald) prospecting for this resource.

4.3.3 Barriers and limitations

For most unconventional resources, there are substantial barriers to development. Access to polar oil is limited both by political access and resource uncertainty – it is not even known if oil exists under Antarctica. There are no known heavy / extra heavy oil or tar sands deposits in New Zealand, and no economic and environmental incentives to encourage exploration.

There are proven oil shale deposits in New Zealand, however the extraction / production technologies are largely untested and technologically complex. A further major obstacle to the rapid development of shale oil resources is the difficulty associated with upscaling i.e. access to heavy mining equipment and supporting water and energy resources. Finally, it is not yet clear whether it will be possible to reclaim a net energy benefit from oil shale production. To date sustained production of shale oil yielding a net energy benefit has not been proven satisfactory, even at pilot scale.

Much uncertainty exists around the net energy gain / return of unconventional oil. Industry analysts have indentified that the Energy Return on Fossil Energy Invested (EROFEI) range from strongly negative (e.g. 0.5:1) to strongly positive (e.g. 8:1 to 12:1). While it is plausible that polar oil production may return strongly positive net energy values (e.g. 30:1) because the production technology is similar to conventional oil, it is also understandable the tar sands and shale oil, which require mining, trucking and heating in order to extract the oil, may actually result in a net energy loss. It is evident that the EROFEI is highly dependent on location (e.g. access to supporting resources) and type of oil extraction. More research in this area is required before conclusive answers can be developed.

Petroleum extraction from “sweet spots” in fractured shales appears to be much more promising - the production technology, environmental impact and EROFEI is much more similar to conventional petroleum production. However, at this point in time it appears that oil production from this resource would be much more capital and labour intensive due to relatively low individual well flow rates and the requirement for complicated drilling, completion and reservoir management techniques (some of which are still under development). This would imply that even for this relatively promising unconventional resource, there is a high level of technical and financial risk.

4.3.4 Introduction to extraction and conversion technology

4.3.4.1 Polar oil

Technically, polar oil production is not substanially different from conventional oil production in difficult environments. The primary differences pertain to designing for high wind speeds, freezing temperatures and sea ice movement. Maintenance and manning of such facilites - located several thousand kilometres away from the nearest service hub - would be logistically very difficult. If production of oil in Arctic regions is used as an indicator, it can be concluded that production of oil from New Zealand’s polar regions will be very expensive and technologically challenging. However there are producing fields in the North Sea at latitude 66°M and in the Barents Sea at latitude 70°N (Snokvit). The Prudhoe Bay field in Alaska is also at latitude 70°N.

4.3.4.2 Heavy and extra heavy oil

Globally, most information on heavy oil production is available from the Orinoco heavy oil belt in Venezuela. Exploitation of many heavy oil deposits can be based on ‘conventional” production technology (e.g drilling of wells into underground reservoirs) complemented by complex reservoir management tools such as the use of solvents, emulsifiers, steam injection or other means of heating. Production facilities and pipelines for heavy oil often have to be heated. In general heavy oil production facilities achieve only rather low flow rates per well, due to the high viscosity of the oil, the usually low reservoir pressure and physical limitations of the production technology. Other commonly used production technologies for heavy and extra heavy oil are very similar to the methods used for tar sand exploitation (see Section 4.3.3.3). Often the transport of heavy oil is so difficult that purpose designed refineries are build close to the production facilities. The resulting oil products can then be exported using conventional transport infrastructure.

Heavy and extra heavy oil is much more difficult and costly to refine than conventional crude oil, and is therefore traded at a substantial discount. In particular the provision of hydrogen for the refining process incurs high costs and high parasitic energy requirements. The high parasitic energy requirements for the refining process, combined with heating requirements at the production facility, are responsible for the much higher life cycle GHG emissions of heavy oil in comparison to conventional crude oil. Furthermore some heavy oil production schemes have been criticised for their high water usage and local pollution of waterways and air. Should heavy oil deposits be found in New Zealand, careful attention will have to be paid to managing adverse environmental effects.

4.3.4.3 Shale oil

Around the world, oil shales have been used energetically for over a century, albeit largely as boiler fuel and for electricity generation (e.g. 90% of electricity generated in Estonia is derived from oil shale). Over the same period efforts to economically extract crude oil from oil shale have been as plentiful as they have been fruitless. In the US, major oil companies (e.g. Shell) have researched and tested the prospects for extracting crude oil from the Western Colorado Green River Formation for many years. While in the past, oil shale was envisaged to be strip-mined like coal and the oil simply “cooked” out of the sediment at a central processing plant, current technology options focus on in-situ processing. This involves the drilling of heating wells into the shale formation followed by 1 to 3 years of steam or electric heating, until the liquid (formed) oil can be extracted via conventional production wells. Groundwater contamination can represent a major problem, which has resulted in the trial of extreme solutions such as freezing walls at the boundary.

While it is difficult to generalise, the quality of oil experimentally produced from oil shale to date has largely been superior to other unconventional oil (heavy oil and oil from tar sands) in regards to sulphur content, hydrogen ratio and viscosity, indicating that less effort may be required to refine shale oil into marketable fuels, with existing refinery technology. However questions regarding a range of other quality factors like stability, oxygen content and particulate contamination have not yet been studied thoroughly enough to draw comprehensive conclusions.

4.3.4.4 Oil from tar sands

Tar sands are the furthest developed unconventional oil resource, with production centred around the Athabasca tar sand deposits in Western Canada. The production of tar sand is rather similar to the production of shale oil. Strip mining combined with central processing are the industry standard, while in-situ production technologies are under development. Contrary to the central processing of oil shale, oil extraction from tar sands mainly involves solvent chemicals and hot water or low temperature steam treatment rather than high temperature cooking, while tar sand in-situ production technologies operate at lower temperatures than shale oil in-situ production technologies.

The refining of oil extracted from tar sands is more energy intensive and complicated than the refining of conventional crude oil, consequently refining is more costly and the price for tar sands is lower than conventional crude oil. The lower processing temperatures for tar sands compared to oil shale is the major reason for tar sand production requiring a parasitic energy consumption of only 25% to 50% (i.e. EROFEI 4:1 to 2:1). However this has to be compared with a parasitic energy consumption of ~ 1% for large and simple conventional oil fields.

Tar sand processing requires large amounts of processing water and is disruptive to the landscape, both due to mining of the raw material in open cast mines and the disposal of mine tailings and spent processing water. Furthermore the enormous amounts of natural gas required for tar sand processing in Canada have been labeled a risk factor destabilising Canada's electricity and domestic / industrial natural gas supply, by industry groups. Currently tar sands supply 1.5 million bbl/day (about 3400 PJ/y) of crude oil, which satisfies <2% of world oil demand. A Swedish study (Aleklett, 2007) has shown that tar sands would not be able to supply a major share of the world's oil supply even with massive government support, mainly due to a lack of resources (natural gas, water, as well as capital and skilled labour). Environmental concerns may further limit the scope for Canadian tar sand expansion in the future.

4.3.5 Asset characterisation

There are no unconventional oil assets proposed for the EnergyScape framework.

All unconventional petroleum developments brought on-stream so far have had far higher production costs than conventional developments. Industry figures (ASPO USA newsletter April 2009) indicate that oil from tar sand mining in Canada requires a floor price of 70 to 90 US$/bbl to be profitable, whereas the majority of the conventional oil can be produced profitably at less than half these prices.

4.3.6 Research status

Based on the low probability of unconventional oil production commencing in New Zealand, the only recommended research directions pertain to keeping options open i.e. watching international developments, and identifying and evaluating New Zealand's resource base.

Figure 4.3.2 – Research status of unconventional oil

(Green highlight indicates 'Fair knowledge', Amber indicates 'Could improve', Red indicates 'Knowledge gap exists')

	International	New Zealand	Comment
Resource assessment	Developing. International oil companies	Developing Private industry, GNS	
Technology development for production	Immature International oil companies, PDVSA, Tar sand developers	None	

4.3.7 Summary

In light of New Zealand's positive prospects for conventional oil, and the numerous technological and economical risks of unconventional oil production, it is unlikely that New Zealand will develop a sizeable unconventional oil industry in the foreseeable future.

The prospects of developing polar oil from New Zealand's Antarctic territory is highly unlikely because of existing international treaties, and non-existant exploration of the region.

There are no confirmed heavy oil or tar sand deposits in New Zealand. Should such resources be identified, it is likely that environmental and economic concerns would severely restrict the development of this resource.

In the absence of major technological breakthroughs, it is unlikely that a sizeable shale oil industry will be developed in this country. Niche opportunities may exist where cheap geothermal heat could be utilised for shale oil production, or where oil shale sweet spots are targeted with more conventional technology.

Section 4.4
Conventional gas

4.4 CONVENTIONAL GAS RESOURCES

4.4.1 General introduction

> *"Natural gas is the only relatively clean alternative to oil and coal, fully supported by commercially effective production and distribution technologies – there is little doubt that natural gas will be the key fuel of the future".*

Source: Douglas-Westwood, Energy Review.net, May 21, 2004

Following the discovery of the Kapuni field in 1959, New Zealand's commercial sector has enjoyed worldwide competitive advantages associated with an abundant cheap supply of natural gas. Ten years later, the development of the giant Maui field spawned a petrochemical era - the "Think Big" projects: Motunui (methanol production + gas to gasoline), Waitara Valley (methanol production), Kapuni (ammonia-urea manufacture). In later years, natural gas under-pinned national electricity generation (e.g. Huntly), and is still the fuel of choice for New Zealand's processing industry and thermal electricity generation sector.

New Zealand's conventional gas resources can be characterised by:

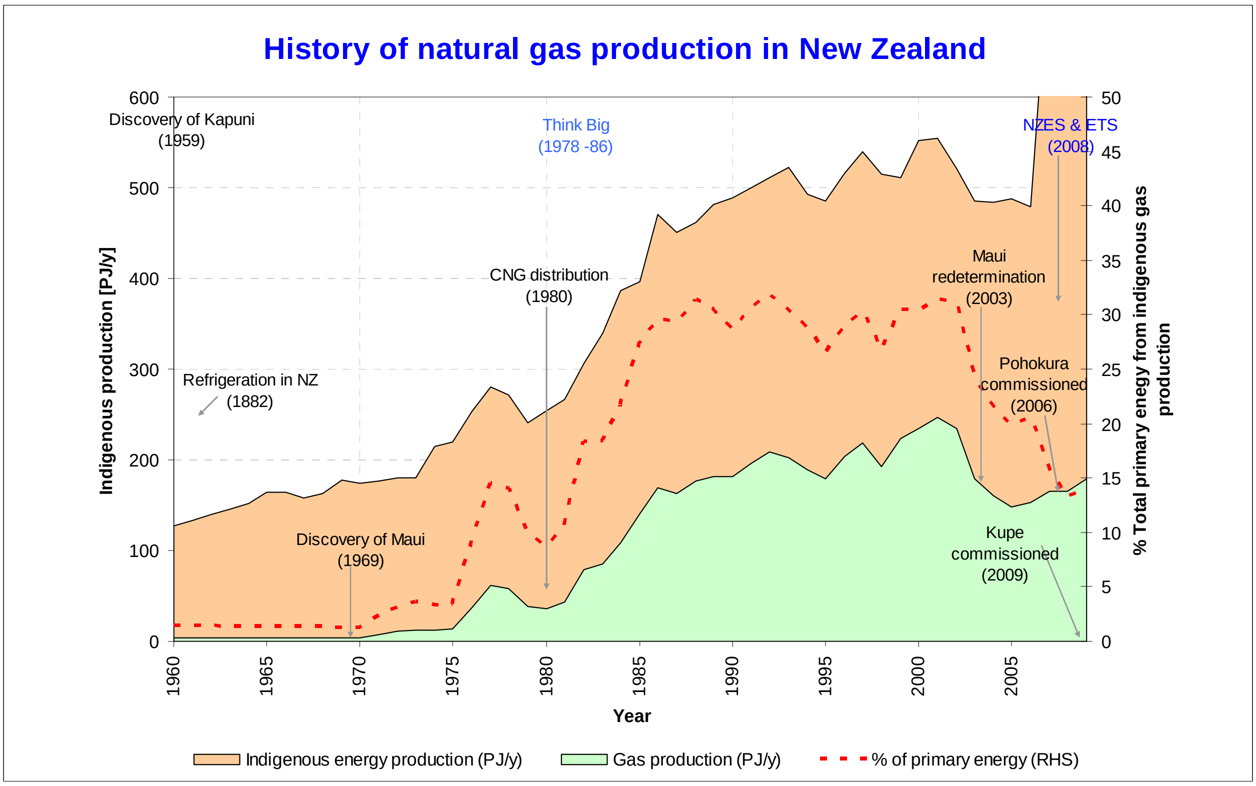
- 1,975 PJ of remaining proven plus proven indigenous gas reserves
- Principal reserve is located in the Maui gas field
- 146 PJ of energy from gas was consumed in 2006
- This was 20% of the total energy consumed from all energy resources
- Highly flexible – ranging from combustion to GTL and CNG.

Natural gas is the logical substitute for coal for economies that seek to swiftly achieve reduction of GHG emissions and local air pollution. The fuel is relatively abundant and relatively low cost, has high thermal efficiency, and significantly (>50%) lower GHG footprint than coal in most applications. Because of these advantages, there is an international trend towards using gas as the preferred fuel for industrial applications and thermal electricity generation.

Natural gas has played a key role in the development of the New Zealand economy, since it supported the development of a petrochemical export industry and supported domestic production of fertiliser and electricity at very competitive prices. Maximum annual production of natural gas (247 PJ/yr) was achieved in 2001. In this year, gas accounted for ~31% of New Zealand's primary energy supply, and ~45% of New Zealand's indigenous energy production (see Figure 4.4.1). In 2006 natural gas production had fallen to 149 PJ/y (~20% of primary energy supply), of which, nearly 56% was used for electricity generation.

The development of the Kapuni field in the 1960s represented New Zealand's first significant gas development. The subsequent discovery of Maui provided a timely substitute for the "dirty" and increasingly expensive and unsafe coal-fuelled town gas plants. The development of Maui involved the installation of the offshore Maui A platform, and separate subsea gas and liquids pipelines to the onshore Maui Production Station at Oaonui. Here the gas is treated, LPG and naphtha separated, and the condensate stabilised before being shipped to refineries. The Maui B platform followed in 1991/2, with all its production being transferred to shore via the Maui A platform.

Figure 4.4.1 – History of natural gas production in New Zealand



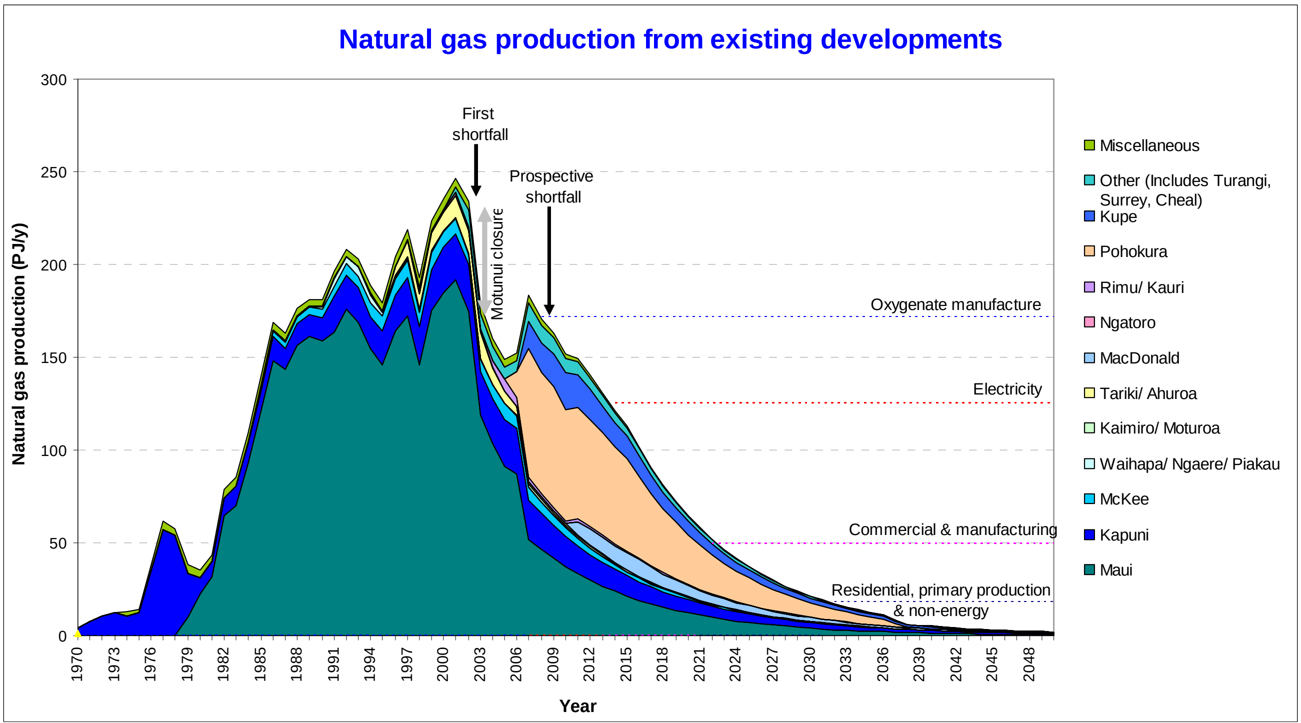
Source: Adapted from MED (2009)

Since natural gas is not readily stored or exported, demand and supply are highly dependent on one another. The development of gas supply is both high risk and capital intensive, hence long-term stability of the gas commodity market is required in order to remain viable. In general, the development of large gas fields will be under-pinned by the construction / operation of large gas consumers such as petrochemical plants (e.g. fertiliser, methanol, gas to liquid plants). Smaller fields are generally developed to offset declines from large gas fields, and to support smaller gas consumers such as industry and electricity generation facilities.

Until recently, New Zealand gas production has fully met local demand. However in 2003, a re-determination of the size of the Maui gas reserves signalled that supply could not match demand. In response, the methanol production plant in Motunui was mothballed, in effect, returning the gas supply market to surplus, and creating ‘potentially demand’ should gas supplies increase. This indicator signals how much additional gas supply could be accommodated without the requirement for construction of new gas demand infrastructure. Because gas supply has not kept pace with the installed capacity, New Zealand now has a significant ‘potential demand’, as summarised in Figure 4.4.2. At the start of 2008, gas supply was firming slightly and Methanex reopened a part of their larger Motunui plant, at the expense of closing their smaller Waitara Valley plant.

Figure 4.4.2 – Summary of New Zealand gas production relative to 'baseline' demand

Current demand allocation by sector is illustrated by dotted lines extending to right hand axis.



Source: Adapted from Beggs 2006, Energy Summit with data sourced from MED, 2008.
The projections are approximate and depend upon the amount and timing of field development.

To avert the potential supply shortfall, New Zealand must either step-up investment in exploration or invest in liquefied natural gas (LNG) import facilities. Considering that New Zealand is still regarded by many in the industry as "a gas exploration theatre", and that an LNG terminal would expose New Zealand's economy to volatile and unpredictable LNG world market pricing and transport tariffs, the development of an LNG terminal is considered to be regressive.

For a country aiming to participate in 'economic transformation', the reliance on an LNG market is comparable to suicide …

4.4.1.1 Investment in exploration and production

Since most exploration companies are preferentially looking for oil and New Zealand's early discoveries (e.g. Kapuni and Maui) were mostly gas-condensate fields, a negative perception that New Zealand was a gas exploration theatre was created. This, together with New Zealand's geographical isolation and very low oil prices during the 1990's, stifled petroleum exploration in New Zealand. The dominance of Maui in the market also diminished any urgency for future energy planning. However, the downward re-determination of Maui reserves in 2003 has had a number of immediate effects.

In January 2009 New Zealand had approximately 1,975 PJ of gas reserves remaining, from 7,187 PJ of initial reserves[8]. These reserves equate to less than a decade worth of consumption, depending on future off-take rates and demand. Presently, the price of gas locally is rising and petroleum exploration activity in New Zealand has been rejuvenated.

The government's energy planning projections predict rising demand and use of gas in the medium term. In keeping with this, in 2004 the government implemented a series of initiatives designed to facilitate and encourage gas exploration here. The new initiatives include pricing changes for Maui gas, resolution of pipeline access, royalty reductions, tax changes, and the acquisition of new seismic data in frontier offshore areas. The latter strategy is similar to that adopted by Australia and other countries. These factors have all led to renewed gas finding efforts.

Although some new exploration licences have been awarded in offshore areas, the initial exploration focus has been, and continues to be in onshore Taranaki. Focus on this region is understandable, considering that it is an established gas province where drilling is cheaper and supporting infrastructure is readily available.

Very few dedicated gas targets have been drilled in recent years, yet a new field (Turangi) was found, in-between the Mangahewa and Pohokura structures. The industry is making considerable effort to find and develop gas in deep reservoirs onshore. The appraisal drilling at Mangahewa led to the announcement by the operator that "significant" new reserves have been found. Formerly-known structures with gas columns at Stratford and Cardiff are being appraised by new wells, but production from these is difficult and total reserves are unlikely to be large. In the offshore East Coast Basin, the Tawatawa-1 well proved to be dry.

The gas exploration scene is changing, since utilities and downstream users of gas have entered into upstream exploration activity. Contact Energy, Genesis Energy, NGC / Vector, Methanex and Mighty River Power have been, or are still involved in: funding wells, taking out licences, or forming Joint Venture partnerships with licence operators. Contact and Genesis have commissioned a joint feasibility study on the importation of LNG to New Zealand.

4.4.1.2 Quality of resource

The quality of gas reserves is usually defined in by level of impurities (e.g. CO_2 and H_2S), and gas liquids content (e.g. "rich" or "lean"). "Lean" gas is predominately methane and is of lower value. "Rich" gas is richer in species which can form condensates (e.g. ethane, propane, butane etc.).

A highly desirable property of the New Zealand gas reserves discovered to date has been the almost total absence of sulphur. The CO_2 content of New Zealand reserves varies widely (e.g., 6.4% in

[8] This total includes all producing and non-producing fields but excludes the offshore Karewa field and the onshore Kahili and Cardiff fields, all of which are undergoing appraisal.

Waihapa-1, 11.6% in Mangahewa-1, 43% in Ngatoro-1, and 45% in Kapuni field). New Zealand gas tends to be "rich" and hence comparatively more valuable.

Table 4.4.3 - Energy densities (Gross / LHV) of New Zealand gas resources

	MJ/kg	MJ/ m^3
Kapuni Wellhead	19.7	25.7
Maui Wellhead	40.3	47.2
Kapuni Processed	50.6	41.3
Maui Processed	48.1	39.3
McKee Processed	47.3	41.3

Source: June 2009 Energy Data File

4.4.1.3 Myth busting

There are four main areas of confusion regarding gas resources in New Zealand:

1. Abundance of gas in New Zealand
2. Need for LNG import
3. GHG emissions from electricity generation
4. Value and efficiency of natural gas use

From a geological perspective, New Zealand's basins are touted as being "gas prone", but this does not necessarily mean that the gas is ubiquitous, easy to find, or even that its whereabouts are known. New Zealand is very lightly explored, in fact only the Taranaki region and associated near shore waters have been subject to thorough exploration. All other potential oil and gas basins are more or less untested and could therefore still contain bountiful resources or alternatively, be devoid of hydrocarbon reserves. Only with ongoing onshore drilling and through exploration of these new frontier regions over the next decades can New Zealand expect continued supply of conventional natural gas.

In the last few years, New Zealand was encouraged to consider the need to install an LNG import terminal in order to protect the economy from a gas shortfall. The rationale behind this suggestion is slightly perverse since the construction of an LNG import terminal would discourage exploration in New Zealand and domestic gas prices would rise to the level of imported LNG. As local gas prices increased, so would exploration activity. Success could mean local resources were once again sufficient without an LNG terminal. The eminently sensible solution for closing the prospective gas supply-demand gap would be to stimulate the gas exploration market through price / research – not the construction of an LNG import terminal.

From an economic perspective, an LNG terminal represents both an export of currency (in exchange for gas), and a capital investment that must be repaid. In order to justify the import of gas, New Zealand must increase exports by an equivalent quantity. Using the imported gas to generate electricity would likely increase the national trade imbalance / current account deficit. The recovery of the capital investment must be recovered via either an increased gas price or cross-subsidy from the tax system. The import of LNG also represents a significant environmental risk – stores of massive volumes of highly flammable materials both onshore and in vessels, can cause great damage when subject to fire, terrorist or military attack (Reynolds, 2004).

There is some confusion as to whether gas is ‘clean’ or ‘dirty’ from a GHG perspective. Natural gas is a fossil fuel which upon combustion releases approximately 52 kton CO_2/PJ - it is by no means carbon neutral! However, in applications such as electricity generation, gas emits much less carbon dioxide than the “dirtier” fossil fuels (coal and oil). For as long as New Zealand requires fossil fuel-fired electricity, either for base load or to cover peak demand, gas is the best choice.

The direct use of gas is both highly efficient and has comparatively low GHG emissions. Most people are probably not aware that cooking with gas uses about a third of the amount of primary energy as cooking the same meal on an electric hot plate powered by gas-fired electricity generation. The same is true for home heating and water heating.

Table 4.4.4 – Cost and GHE emission comparison for different heating options

	Typical cost ($) per GJ delivered (2005)	kg CO_2 per GJ delivered
Direct heating with gas	28	52
Heating with gas generated electricity	54	157
Heating with national grid electricity	54	95

Even though the advantages of using gas directly are quite evident, it is unlikely that there will be a major public switch from electricity to gas, because: electricity is universally and conveniently available; changing appliances can be expensive, and there is a perception that gas supply may run out. The later is very unlikely since the reticulated gas market in New Zealand is sufficiently small that current gas fields (and future reserves discoveries) will easily cater for this demand.

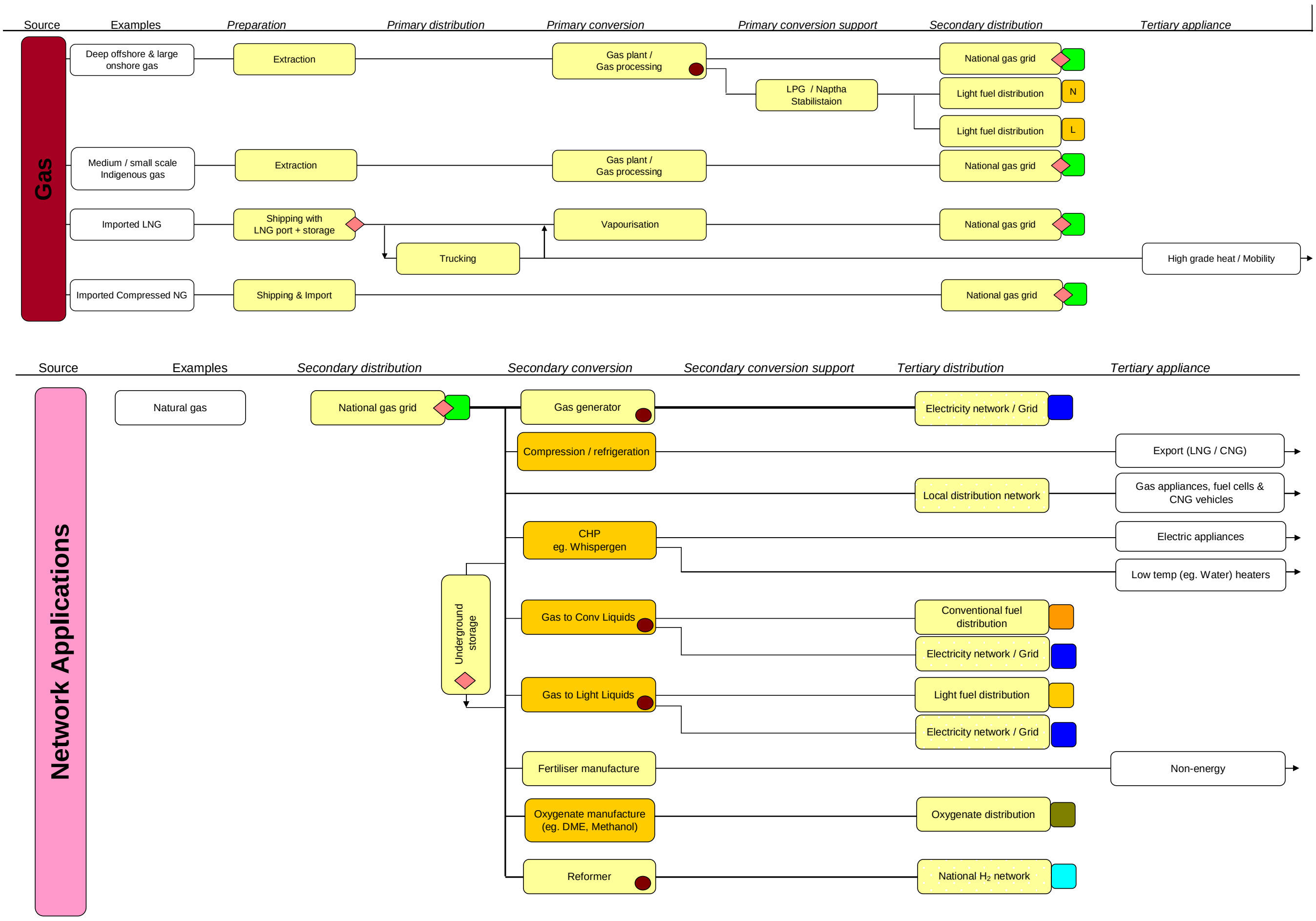
Considering that there is a finite supply of natural gas, it is prudent to use this resource to yield high value products that cannot be generated with other resources. Petrochemical products such as fertilisers and methanol have high financial value and cannot be easily produced from alternative resources; they should be considered one of the highest priority uses for gas. Gas fired electricity generation by comparison, provides less national economic benefit, while a multitude of generation alternatives are readily available. It should therefore be considered a lower priority. As indicated above, the direct use of gas for heating, or as a transport fuel (CNG vehicles), is a more efficient use of gas than electricity generation, and should therefore be of intermediate priority.

4.4.1.4 Pathways

For numerous reasons[9], natural gas is one of the most versatile energy sources – it can cost effectively provide low and high grade heat; provide fuel for electricity generation and be a cost effective transport fuel. The key pathways are defined in Figure 4.4.5, with those assets specific to the source of gas identified in the upper panel, and the conversion assets common to the gas network defined in the lower panel.

Figure 4.4.5 – Natural gas energy pathways

(Assets specific to gas source in upper panel; Conversion assets common to gas network in lower panel)



A full view of the pathway is presented in the Pathway Overview Map at the start of this document.

The national gas energy pathways were defined by two indigenous gas sources and two import sources, namely:

1. Deep offshore and large onshore gas reserves
2. Medium / small scale indigenous gas reserves
3. Imported liquefied natural gas (LNG)
4. Imported compressed natural gas (CNG)

[9] Including chemical simplicity, relatively low cost, relatively low GHG footprint, low transportation cost etc.

4.4.1.4.1. Indigenous gas sources

Indigenous gas is sourced from a reservoir via a wellhead. The wellhead can either be located onshore or on an offshore production platform. Modern directional drilling techniques have meant that offshore oil reservoirs can be recovered by onshore wellheads – 20 km is considered the extreme range of this technology. Gas and gas condensates which are recovered at the wellhead are often saturated with water and arrive at the surface predominately as a gas phase, with entrained liquid phases. The recovered fluids are transported with gathering flow-lines to gas processing plants.

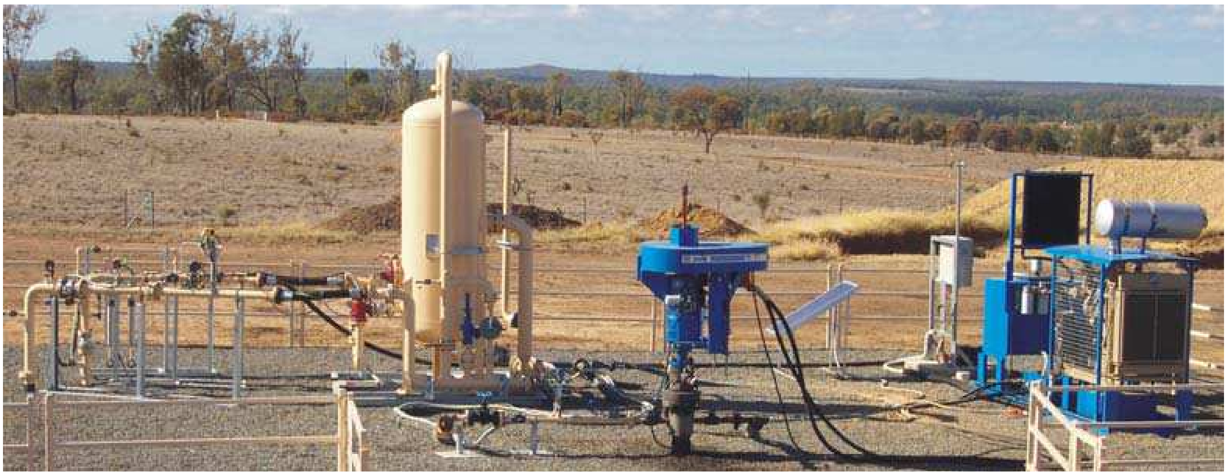
The function of gas processing plants is to ensure that gas which is exported to customers (most often via the national gas grid) will burn cleanly and will not drop-out liquids during transportation. The quality levels required for exported gas are generally defined by specification of carbon dioxide (CO_2) and sulphur content, Wobbe index and hydrocarbon dew point standards contained in the New Zealand pipeline specification (NZS 5442) or other relevant Transmission Service Agreement (TSA). To achieve these standards, gas plants must:

- Reduce the concentration of contaminants e.g. CO_2 and sulphur,
- Separate heavier hydrocarbons (i.e. condensate) from the gas phase,
- Reduce residual water content with dehydration technology, and
- Compress sales gas to the pressure (typically ~30 bar) required for transmission / sale.

The required level of contaminant reduction, hydrocarbon dew pointing and dehydration required is dependent on the quality of the raw gas and value of condensates. Compression equipment is often a large fraction of gas plant areal footprint and a cost.

We have distinguished two different scales of gas plant development: (i) large scale and (ii) medium / small scale. Although the technologies applied at both scales are similar, the cost efficiencies of large scale plants enable additional supporting infrastructure to be built such as: Support structures required for deep offshore developments; LNG plants & export terminals; gas monetising assets e.g. gas to liquids plants, fertiliser plants.

Figure 4.4.6 – Typical gas field wellhead



4.4.1.4.2. Natural gas import

Natural gas can also be imported into New Zealand, but this product is not readily transported. The advent of containerised and bulk shipping revolutionised the quantity of trade between nations, but most of the products traded were solid or could be packaged. Non-volatile liquids (e.g. crude oil and water) can also be readily transported in shipping tankers. The shipping of a product which is generally in gaseous form is considerably more difficult and expensive. Two different transport technologies are relevant:

1. Liquefied natural gas (LNG)
2. Compressed natural gas (CNG)

The international transport of natural gas at a high density (i.e. liquid form) is a relatively recent technological pathway. Specialist engineering (including developing refined metals capable of operating at cryogenic temperatures) and enormous scale were required in order to make the technology commercially viable. The first LNG cargoes were delivered in 1959.

The transportation of LNG requires the refrigeration of natural gas to -160˚C in liquefaction plants. These plants are technically very complex, with vast heat exchange and further gas refinement. In order to be cost effective, these plants must be of significant scale (i.e. >300 MMSCFD; 125 PJ/y). The supporting infrastructure must all be of similar scale – this infrastructure includes: LNG export storage and terminal; LNG super tanker vessel; LNG import storage and terminal.

Figure 4.4.7 –Typical LNG port infrastructure

NOTE: The physical separation is important for safety reasons.

The capital investment and risk in LNG super tankers is massive – for cost efficiency, the tankers carry over 120 million m³ (~2.5 PJ[10]) of LNG; Safe storage of LNG requires complex metallurgy and precision manufacturing; Mitigation of a terrorist risk requires a double hull and active defence capability. To justify such risk and investment, LNG contracts are generally large 'take or pay' arrangements with designated loading and unloading ports. Historically, LNG carriers have had dedicated transfer routes for their lifetimes, but there have been recent signs of a spot market opening up. If New Zealand were to see some of this market, the price would probably be relatively high due to the small scale of demand and distance of transportation.

If New Zealand were to secure an LNG contract, then an LNG specific import terminal would need to be constructed. The terminal would require a jetty (or offshore mooring), a marine offloading arm, cryogenic pipe work, specialist low temperature tankage, as well as a re-vaporisation and recompression facility. The facility may also require double containment, "terrorist proofing", and robust design to meet seismic conditions. The international rule of thumb cost for a 1 bcf/day (~400 PJ/y) LNG receiving terminal is US$1.5 billion. A suitable terminal for New Zealand would be smaller, but its cost can be expected to approach $1 billion, depending on size, location[11] and jetty length.

A proposed international gas transportation pathway in competition with LNG is transportation of compressed and refrigerated (~80 bar and -30˚C) natural gas. It has been suggested that for short international hauls, e.g. between Australia and New Zealand, CNG transportation may be more cost effective than LNG shipping. This pathway has almost all of the same capital investment, safety and contractual limitations of the LNG pathway, albeit cheaper because the metallurgy required is far less extreme. This pathway is still at pilot stage and has not had significant commercial interest. This pathway shall be considered as a sub-set of the LNG transport pathway, and will not be addressed further.

It should be pointed out that Liquefied Petroleum Gas (LPG) primarily consists of propane and butane, and hence is very distinct from LNG (which is primarily methane). When under pressure (at ambient temperatures) LPG is a liquid and is therefore transported much more easily. This fuel can be readily transported in a network e.g. Christchurch has a reticulated LPG network. More details of this system can be obtained from Section 5 - Distribution infrastructure.

[10] LNG tankers have been compared to small nuclear bombs, and in terms of energy capacity, this argument has merit i.e the largest LNG super-tanker is designed to carry a cargo of 5430 TJ. Typical LNG super-tankers are half this size. The nuclear bombs dropped on Hiroshima (63 TJ) and Nagasaki (84 TJ) are considered very small compared with most current devices (<4,000 TJ). But risk characterisation can be challenged i.e. LNG tankers are designed to minimise explosion force, whilst bombs are designed to maximise explosion force.

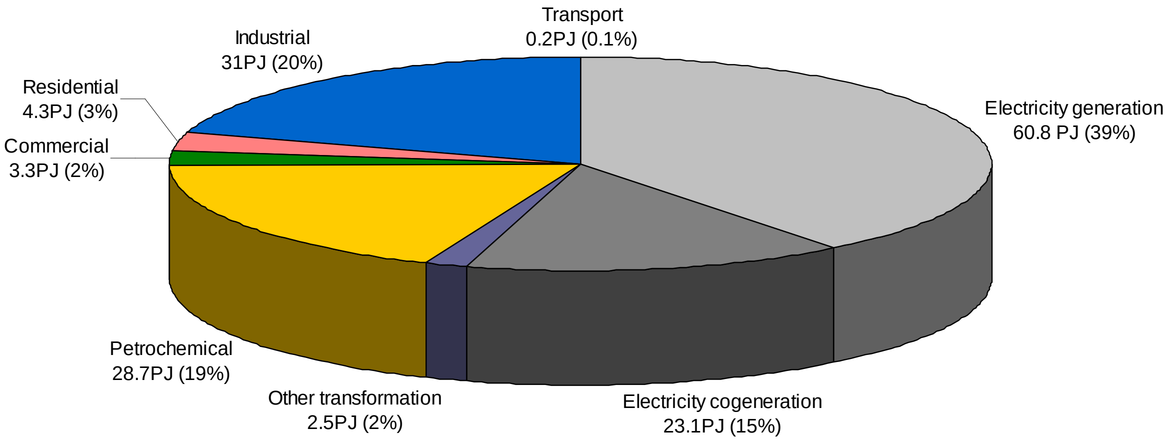
[11] Only Taranaki and Northland can realistically be considered.

4.4.1.4.3. Common natural gas pathways

The versatility of natural gas lends itself to many different uses. We have characterised the potential demand in seven classes, with increasing levels of complexity and investment:

1. Domestic / commercial reticulation e.g. appliances, fuel cells and CNG vehicles
2. Electricity generation
3. Combined heat and power
4. Petrochemical industries e.g fertiliser (urea, DAP, CAN etc), hydrogen peroxide and plastic manufacture
5. Oxygenate manufacture e.g. methanol, DME, MTBE, ethanol
6. Natural gas export e.g. LNG, CNG
7. Gas to liquids (GTL) – both conventional liquids and light liquids

Figure 4.4.8 – Profile of current natural gas demand



Source: Adapted from MED (2009)

Demand for natural gas in New Zealand has changed markedly among different sectors over the last 50 years. This is due to continued economic development, and a shift by many industrial applications (such as dairy processing) from coal to more convenient natural gas. In the late 1860s most towns had their own reticulated gas systems, carrying gas made from bituminous coal[12]. The early New Zealand natural gas developments (e.g. Kapuni) sought to substitute coal derived town gas with a safer and more convenient fuel. In the late 1990s gas had become a preferred fuel for direct-heat reticulated applications in industrial plants (PEPANZ, 1999). Since the mid 1970s, natural gas demand for electricity generation increased strongly. While the initial generation plants using natural gas (New Plymouth and Huntly) were steam plants, able to also utilise a wide range of fuels such as fuel oil or coal, more recent developments (such as Taranaki combined cycle, Otahuhu B and Huntly e3p) have been designed to use natural gas exclusively. Since the New Plymouth power station has been retired and Huntly has switched to burning coal, it can be concluded that the natural gas demand for electricity generation has become more entrenched as

[12] http://www.teara.govt.nz/en/energy-supply-and-use/7

newer plants are unable to switch fuels. The gas demand for electricity generation has gradually increased over the last 30 years, and the sector has become the single biggest user of natural gas in New Zealand.

The source of natural gas for most users is the reticulated natural gas grid. The early reticulation systems that were established in the 1860s were connected by a national gas grid linking Auckland and Wellington in 1969. This network was further extended with the development of the Maui field and associated "Think Big" projects. Even thought there are now over 230,000 individual users of natural gas in the North Island, most of them residential gas customers, the bulk of the demand originates from a small number of large users in the electricity generation and petrochemical sectors. Some of the main industrial users of gas include: forestry and wood processing, dairying, steel, cement and aluminium manufacturing. Gas consumption in the reticulated industrial market is expected to continue with unconstrained gas supply. The current demand for natural gas by this sector is approximately 38.6 PJ/y.

During the 1980s and 1990s, New Zealand pioneered the use of natural gas in vehicles - in the form of CNG (compressed natural gas). By mid 1980, almost 6 PJ/year of natural gas was used for transport. The removal of subsidies, and a very low oil price during the late 1990s, all but eliminated CNG for transport demand – now only 0.19 PJ/y.

Although most of New Zealand's CNG infrastructure has disappeared, in an emergency situation CNG would offer the largest and most readily available source of domestically available transport fuel. Over a

Snapshot – Compressed natural gas (CNG) in New Zealand

New Zealand was the first country in the world to develop a large scale CNG economy. During the 1970's and 1980's a number of grant and interest free loan schemes helped establish a network of 750 CNG refuelling stations in the North Island. The government also offered low-interest loans for the conversion of motor vehicles to CNG. However, conversions were not cheap (costing on average $3,500 in 2005 dollar terms). Compressed natural gas was very popular in the early 1980s when oil was still very costly following the second oil shock. As oil prices dropped in the late 1980s and early 1990's CNG lost its cost advantage.

CNG demand peaked at 5.85 PJ/y in 1985, which represented 7.85% of national petrol consumption (MED 2006). Since then a number of factors have contributed to the almost complete disappearance of CNG filling stations and CNG vehicles in New Zealand. These factors include: Removal of government support for CNG and lack of favourable tax regime; very low oil price during the 1990's as well as opposition from the oil industry.

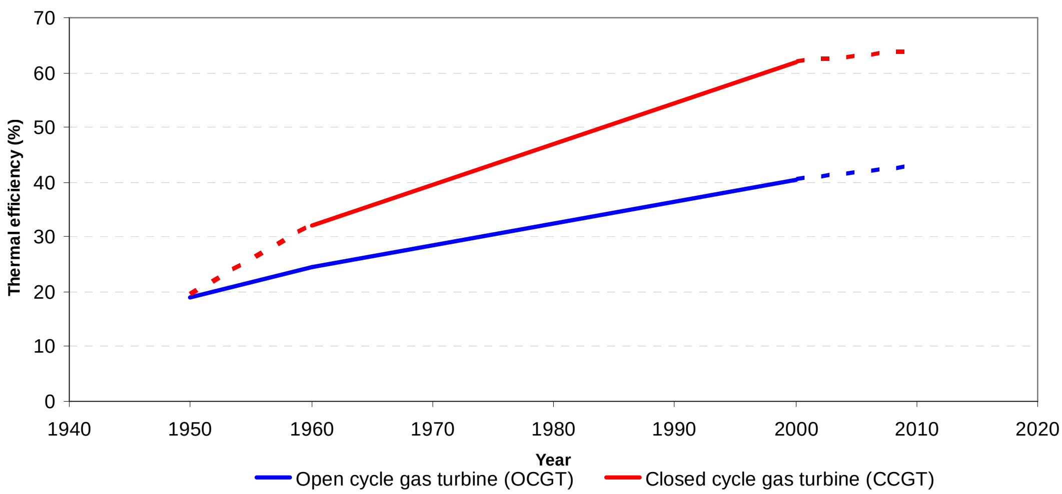
Overseas, CNG technology continues to gain in popularity, with several countries becoming key markets for New Zealand made CNG equipment. While many vehicle manufacturers broaden their range of dedicated CNG vehicles, governments in Europe and Asia support CNG through advantageous tax regimes. Other countries like the UAE have set firm targets of increasing shares of liquid transport fuel to be replaced with CNG. Argentina, Brazil, Germany, Pakistan and the US have now established CNG refuelling networks larger than New Zealand at its peak.

2 to 4 year period, the volumes of CNG that could be made available would be several times greater than the combined domestic production capacity of ethanol and biodiesel that could be installed over the same time period. New Zealand still has a sizeable workforce with CNG experience as well as world-renowned CNG equipment manufacturing capability.

In the last decade, the use of gas for electricity generation became an attractive investment. This recent phenomenon was a result of deregulation, liberalization and privatization of the energy sector and subsequent technical advancement of closed circuit gas turbine (CCGT) technology. As illustrated in Figure 4.4.9, the energy efficiency of the latest generation of CCGT plants is considerably improved over previous generations. These CCGT efficiencies have been achieved without compromising investment cost or plant reliability, consequently, this technology is unrivalled among fossil fuel generation technologies (Susta and Greth, 2008). Specific advantages of this technology include:

- Very efficient operation
- Specific installation costs are comparatively low
- Installation timeframes are short – typically less than two years
- Natural gas has less GHG emissions per unit of energy than other fossil-fuel sources
- Gas demand increment can be relatively modest, which also means capital risk is also only modest
- Price of output product is based on domestic market, which will ultimately cover the cost of investment (cf. petrochemical products which are linked to international commodity pricing).

Figure 4.4.9 – Improvement in efficiency of gas turbine power plant



Source: Adapted from Susta and Greth (2008)

One of the strongest criticisms of electricity generation using gas turbines (as above) is the waste of heat that is generated. Even if a plant is 60% efficient, it will convert ~40% of energy to heat. This heat is generally dissipated into rivers or atmosphere (via cooling towers). If heat demand can be identified in the area, then much more of the input energy can be used. The concept of capturing both heat and electricity from the input fuel is the concept behind co-generation and combined heat and power (CHP) systems. It is worth mentioning that the small and household scale combined heat and power system has finally reached a point of commercial reality, and has been identified as a technology capable of transforming energy efficiency. For more detail on this technology please refer to Section 6.4.4.

From the perspective of New Zealand’s economic development, using gas to produce export products is more valuable than producing electricity. New Zealand’s petrochemical industries produce methanol which is exported, and fertiliser which directly substitutes imports. The development of these industries was stimulated by the development of the Maui gas field in the 1980s, through the “Think Big” initiative.

The first of the “Think Big” projects was the Kapuni Ammonia Urea plant, which commenced manufacture in 1981. This plant uses natural gas to produce fertiliser. The plant was designed to match New Zealand’s current and future urea demand - 470 tpd using ~20 PJ/y. Because this plant was much smaller than the then world conventional standard size unit (1,500 tpd) it could not be economically justified as a competitor to fertiliser import. The plant was commissioned in 1983, and twenty five years later, it is still running well. Its capacity has been increased several times, but it can no longer meet the full local demand for urea - the usage of which has increased greatly with the boom in dairying. The Kapuni Ammonia Urea plant can be expected to remain online for as long as economic sources of gas feedstock continue to be available.

The second “Think Big” project based on gas conversion was the Waitara Valley methanol (MeOH) plant (see Figure 4.4.10) commenced production in 1982. This plant was only medium scale by world standards and, while it met all of New Zealand’s demand (mainly associated with resins for wood processing), the majority of the MeOH (chemical grade) product was exported from Port Taranaki.

Figure 4.4.10 – Methanex methanol plant at Waitara Valley

The largest gas based "Think Big" project was the Motunui methanol to gasoline (MTG) plant. The project was the most contentious, and arguably the least successful in returns to the taxpayer. The gas to methanol part of the plant had two production trains, each with 2,600 tonne/d capacity - the largest in the world at the time of construction[13]. The methanol to synthetic petrol (i.e. gasoline) plant was based on Mobil technology which used the ZSM-5 Zeolite catalyst. The plant consisted of five identical trains with an aggregate maximum design capacity of 2,200 tonne/d[14]. Unfortunately, by the time it began producing in 1987, the price of imported petrol was dropping. Instead of full production of synthetic petrol, the plant switched to making more methanol. Although technically proven, the manufacture of synthetic petrol from methanol did not prove successful economically and was subsequently abandoned in 1997. The natural gas demand from methanol production in New Zealand was very price sensitive and volatile. As cheap Maui gas supplies dwindled by the mid 2000s, methanol production was markedly scaled back. However increasing world methanol demand and uncertainty about natural gas supplies in other world regions witnessed a resurrection of New Zealand methanol manufacture. The methanol manufacturing plants are reaching the end of their economic life, but still have sufficient production capacity so as to be considered the "swing user" of natural gas - able to soak up over supply and cut back when gas is in short supply.

The development of liquefied natural gas (LNG) transport technology over the last thirty years, opened up another natural gas export pathway. The technology required is briefly discussed in Section 4.4.1.4.2. Although LNG prices are set by global benchmarks, the long-term nature of supply contracts means the market is steady because most supply contracts are long-term.

Converting natural gas into a transportation fuel using gas to liquid (GTL) is a highly capital and energy intensive operation. The technology was proven during the second world war and has subsequently been applied at Sasol, South Africa and Bintulu, Malaysia. More details regarding this technology are supplied in Section 6 – Secondary conversion.

4.4.1.5 Scale

The scale required to achieve viability of gas discoveries differs considerably from oil discoveries. Unless a discovery is sufficiently large to justify the billions of dollars required to construct a world scale LNG or methanol (MeOH) facility, gas development is constrained by the size of the local gas market. It should be noted, that new technology to produce LNG from offshore floating facilities may alter the market dynamics and viability of exploring for gas.

Currently, the New Zealand market can accommodate (and indeed urgently needs), one or two mid-size field onshore or close to shore developments within the next few years. The typical size of gas consumption assets is considered below.

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13 http://www.ipenz.org.nz/heritage/itemdetail.cfm?itemid=68
14 http://nzic.org.nz/ChemProcesses/energy/7D.pdf

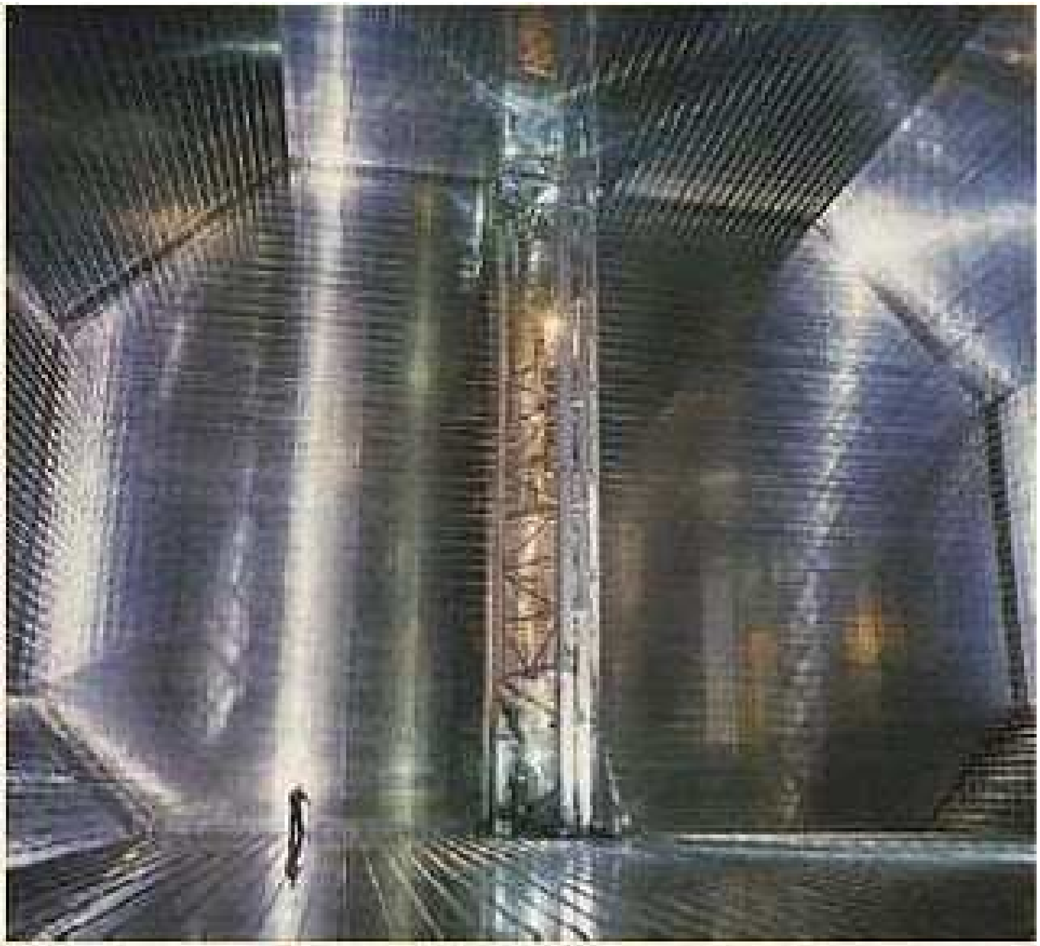
Table 4.4.11 – Expected demand of typical gas consumption assets

Description	Demand (PJ/y)	Comment
10,000 homes	0.27	Assuming each home uses gas for space heating, water heating and cooking (7,590 kWh).
300 MWe electricity generator	12	Assume 55% conversion and 70% loading. e3p is 380 MWe
1,500 tpd ammonia urea plant	64	Kapuni was 470 tpd
2,500 tpd methanol plant	38	Motunui was 2,600 tpd/train
20,000 bbl/d GTL plant	85	Assume 59% conversion. Bintulu is ~14,700 bbl/d
LNG export	250	Assuming 2 @ 300 MMSCFD trains.

Based on the ‘potential demand’ assessment in Figure 4.4.2, it could be suggested that discoveries less than 1,000 PJ are unlikely to support a step change in New Zealand gas demand. If New Zealand seeks to achieve a substantial economic transformation, then a gas discovery capable of supporting either a GTL or LNG plant, (i.e. larger than 2,500 PJ) would be required.

Table 4.4.12 – Demonstration of enormous LNG gas storage scale

A person within a LNG super tanker storage pod



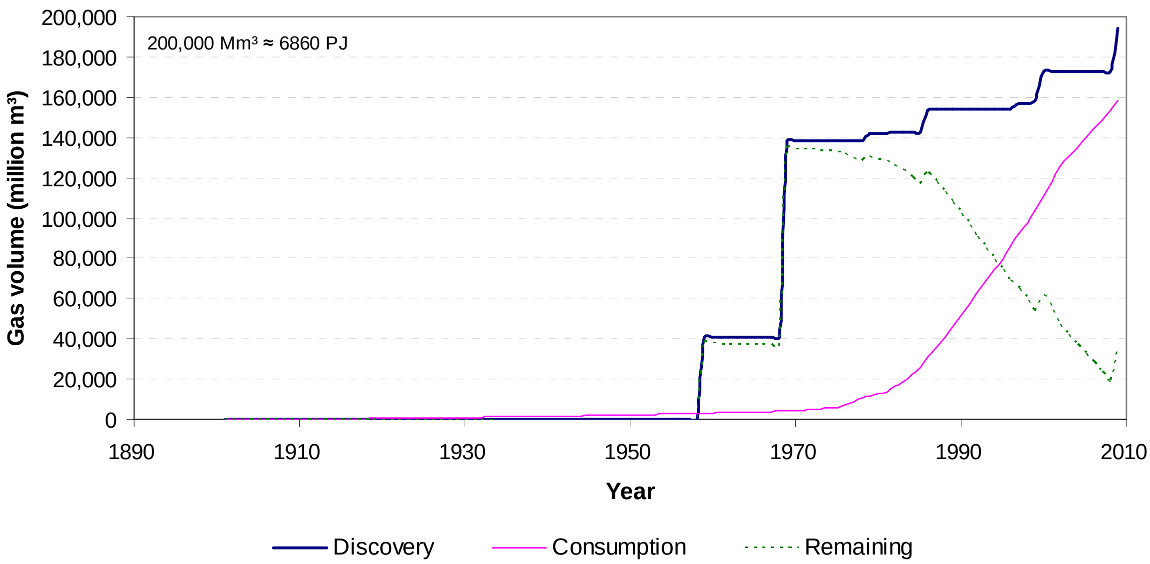
Source: http://mylifeatsea.blogspot.com/2007_07_01_archive.html

4.4.2 Introduction to the resource

The quantity of gas that has been discovered but has not yet been extracted – remaining reserves – has been in steady decline since the commissioning of Maui in 1969 (see Figure 4.4.13). Based on current rates of consumption, remaining gas reserves account for less than a decade of additional production.

'Peak gas' is a concept akin to 'peak oil' i.e. an indicator that maintaining production rates is becoming more difficult, and pre-empts (by 30 years) a period when consumption will be constrained by production rate. Based on the simple indicator of "peak gas" (i.e. when 50% of reserves have been used), New Zealand achieved this threshold in the mid-1990s and by inference will have supply – demand tension early this century. The concept of "peak gas" has less relevance in New Zealand because there has been relatively little exploration, and hence there is significant expectation of new large finds in the future.

Figure 4.4.13 – Cumulative gas discovery and consumption



4.4.2.1 Reserves

The current New Zealand gas reserves are tabled in successive versions of the Energy Data File and are summarised in Table 4.4.14. At the start of 2009, roughly 30% of New Zealand's total gas reserves were left, that is, 1,975 PJ out of a total of about 7,187 PJ (see Table 4.4.14). Since New Zealand's gas consumption can vary between 150 and 200 PJ per year, there is currently limited security in long term gas supply. Even with the recent new field developments of Pohokura (900 PJ), Kupe (188 PJ) and Turangi (147 PJ) there is a fair prospect for a gas shortfall within the next decade.

The spreading out of production timeframes means that there will be a gas supply shortfall in the foreseeable future, the amount of which will both influence, and depend on, demand and associated market price. Even if new fields are found, the long lead times to discovery, appraisal and development will most likely result in a supply crunch in the interim. The Energy Outlook to 2030 (MED, 2006), suggests that the projected supply deficit will occur in 2013. A similar scenario was suggested by Beggs (2006). The first shortfall actually occurred in 2005, when Methanex was forced to reduce its methanol output.

Other factors that lead to uncertainty in future gas availability include:

- Optimal reservoir performance and financial returns require production to be spread out over a relatively long time period e.g Kupe production will be approximately 20 PJ/year for eleven years; Pohokura will produce at approximately 50 PJ/year for ten years before going into decline (Huckerby, 2004).
- Field development lead times can be delayed by lack of capital or access to drilling equipment
- Existing fields may decline faster than expected (cf. Maui redetermination)
- Remaining reserves calculation exceeds reality (key uncertainty).
- Field discovery rate (key uncertainty)

Table 4.4.14 – Summary of reserves and production as at 1 January 2009

Note: The Kupe field is now in production

	Ultimate recoverable (P50)		Remaining (P50)	
	Mm³	PJ	Mm³	PJ
Producing fields				
Maui	102,866.0	4,051.0	7,761.0	306.6
Kapuni	37,300.0	996.0	4,399.0	118.0
Pohokura	28,192.0	1,167.0	24,451.0	1,012.0
Kaimiro / Moturoa	897.6	33.3	515.4	19.1
Ngatoro / Goldie	807.0	29.9	535.2	19.8
Tariki / Ahuroa	3,270.7	128.8	80.6	3.0
Waihapa / Ngaere	816.6	32.1	17.6	0.7
Rimu / Kauri	623.0	25.8	10.5	0.4
McKee	5,173.5	208.0	1,206.6	44.7
Mangahewa	3,335.7	129.8	2,044.5	75.8
Others	4,898.8	181.6	4,615.6	171.1
Sub-total	**188180.9**	**6983.3**	**45636.9**	**1771.2**
Non producing fields				
Kupe (PML 38146)	5784.3	188.1	5784.3	188.1
Urenui/Ohanga (PMP 38161)	n.a	10.5	n.a	10.5
Radnor (PMP 38157)	152.4	5.0	152.4	5.0
MacDonald	n.a	n.a	n.a	n.a
Windsor (PMP 38152)	2.8	0.1	2.8	0.1
Sub-total	**5939.5**	**203.7**	**5939.5**	**203.7**
Total	**194120.4**	**7187.0**	**51576.4**	**1974.9**

Source: June 2009 Energy Data File

The MED Energy Outlook to 2030 base case scenario assumes that 60 PJ of new gas discoveries will be made per year, giving an overall increase in gas supply of 35% over the period to 2030. The 60 PJ/per year discovery rate is the average for the post-Maui era (since 1970). In this scenario, a supply shortfall would occur in about 2024. Implicit additional assumptions are that the discoveries are produced in a timely way, and that one or more significant discoveries will be made immediately, in order to be developed in time to stave off the predicted shortfall.

Compared with other petroleum regions internationally, there have been relatively few discoveries in New Zealand. If the total reserve additions are averaged over the nearly five decades since the discovery of Kapuni, then the annual discovery rate has slowly declined to a level at the end of 2005 of about or just below our current annual gas usage (Beggs, 2006). Although the incremental reserves provided by the recent Pohokura discovery are significant, they produced barely a blip on the long-run annualised average. Several new fields of similar size will need to be found in the next 5-10 years to achieve sustainable replacement reserves. Based on the premise of 1 commercial successful well per 10 wells drilled in frontier areas, dozens of wells will be required over the next 20 years. Such a level of drilling activity has not yet been seen in our offshore waters.

There is plenty of scope to find one or more very large gas fields. However, the majority of fields found are likely to be small (say 50-200 PJ). If these smaller fields are the only ones found, then we will need to find a lot of them, which also means that a lot of wells have to be drilled. Fields of this size will have to be onshore or close to shore to be commercial.

Deep gas reserves are already known to be present in fields such as Cardiff and Mangahewa, although the actual size of these fields is unclear. The Crown Minerals website records Cardiff reserves as 34.2 BCF, (for one reservoir level only), but other reports state estimated reserves at 200 BCF or 165 PJ. Mangahewa field reserves have been progressively reported as “100 BCF”, then “potentially up to 250 PJ”, and more recently as “considerably more gas has been found”. On the assumption that reserves are big enough to exploit, the biggest production issue is, however, that the deeply-buried reservoir sands have low permeability and poor flow rates. The secrets for improving extraction of this gas are still being sought.

The full extent of our gas resource, either in Taranaki or other basins, is unknown. However, with a vast offshore territory that is relatively unexplored, there remains huge potential for other world-class fields such as Maui to be found. If one more field the size of Maui were found, its gas would today[15] be worth $NZ 49.5 billion.

4.4.2.1.1. Reserves calculation

The same methods are used to estimate the possible size of future gas discoveries as those for oil discoveries (see Section 4.2.2.1.1). One distinction between the two is that calculations of gas reserves generally apply a recovery factor, or proportion of in-place resource that can be extracted, of over 50% (the actual value applies depends on reservoir quality), which is somewhat better than that allowed for oil recovery.

[15] Based on weight average gas price for 2008 of $12.2/GJ

As is the case for oil, reserves estimation in the early life of a field can be difficult, and often errs on the side of being too conservative. When the Kapuni field was discovered nearly 50 years ago, reserves were initially estimated to be 250 PJ. Following the long intervening period of appraisal and production, total reserves are now estimated to be four times the original volume (1,100 PJ).

4.4.2.2 Resource uncertainty

The true volume of New Zealand's oil and gas endowment will never be known unless every conceivable habitat for oil and gas is drilled, which is improbable at best. The resource is hidden in the sub-surface, and the area within which oil and gas might be found is huge. Moreover, 96% of New Zealand's Exclusive Economic Zone (EEZ) and extended continental shelf (ECS) is under water, which increases the logistical cost of exploration. New Zealand's marine territory is about ¾ the size of Australia and there are still tens of thousands of square kilometres that are totally unexplored. The cost of offshore data acquisition and interpretation is non-trivial. At least $50 million is required over the next decade.

In addition, New Zealand's geology is complex, being that it is astride an active tectonic plate boundary. This means that the various geological parameters required for oil and gas to form are also complex (they include: source rock structures, from which petroleum is generated and expelled; migration pathways, along faults or permeable carrier beds; reservoir rock, where it is stored; trapping structures and sealing cap rocks). These parameters are all highly variable in a vertical, stratigraphic sense and spatially, within basins and from basin-to-basin.

The bottom line is that no-one knows the full areal extent of petroleum occurrence or the total volume of oil and gas reserves that could be at New Zealand's disposal. Most "guesstimates" are just that. Many, many more exploration wells are required across New Zealand as a whole before we can attain a more complete empirical understanding of our in-ground petroleum resource and producible reserves.

There will be, of course, many more fields present in the subsurface than will be found, no matter what. Only structures or stratigraphic traps of reasonably large size will be drilled in the first place. The pre-drill size cut-off will depend mainly on economic factors, such as: current market supply and demand balance; proximity to market and infrastructure; remoteness from industrial engineering bases; availability of rigs; commodity prices; political policies etc.

4.4.2.2.1. Estimation of resource extent

Maps of sediment thickness (above non-economic basement rocks) provide a "first-look" proxy for evaluating the petroleum prospect of a region or basin on the premise that, if the sediment cover is too thin, petroleum will not have been generated. These maps are derived from seismic reflection profiles or from data on the region's gravity field. With either data source, geological assumptions and mathematical algorithms are required to convert the input data to inferred sediment thickness.

The threshold sediment burial depth below which oil and gas generation may have taken place can be deduced using a sophisticated computational method, broadly termed “basin modelling”. This method calculates predicted volumes of oil or gas generated from inferred source rock “kitchens” over specified depths, geological times and geographic areas. The input data are again based on subsurface mapping and a large number of geological assumptions, such as the type of source rock, geothermal gradient, depth of source rock burial and duration of burial.

Basin modelling can also discriminate between the likelihood of oil versus gas being found. This method allows explorers to prioritise areas to drill in, but on its own does not predict the exact location or size of individual future discoveries. A rule of thumb in New Zealand basins is that only a small proportion - perhaps about 1% - of the generated hydrocarbon volume is ultimately retained within traps.

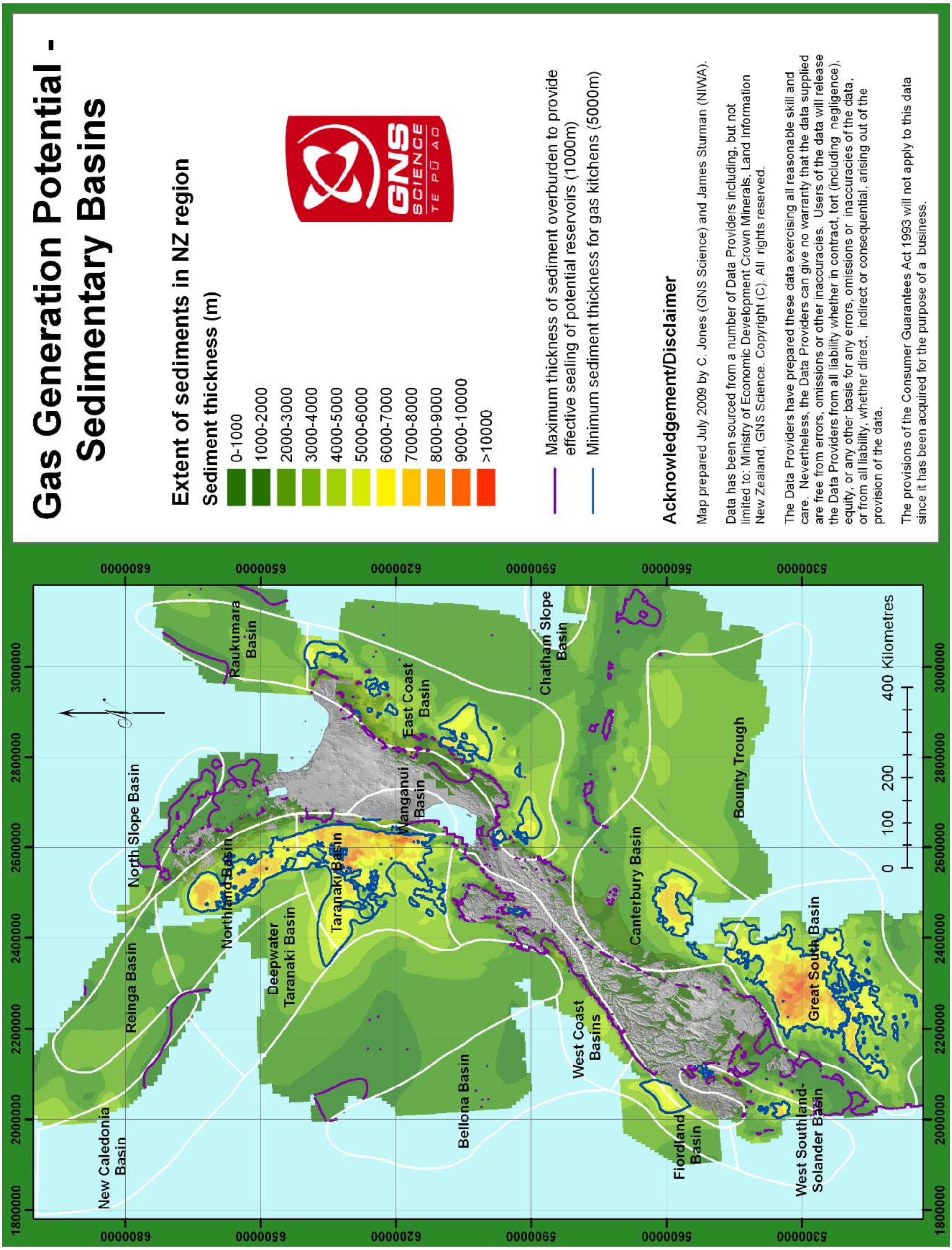
Figure 4.4.15 shows a simplified sediment thickness map of the basins around New Zealand. Another rule of thumb is that source rock in New Zealand needs to buried to at least 5,000 metres depth below the surface before gas generation and expulsion from source rocks begins. Therefore, any region on the map with a sediment thickness of >5,000 metres can be regarded as a potential gas kitchen (assuming the presence of suitable organic-rich source rocks). The main gas “window” is generally between 5,000 and 6,000 metres depth. There is some depth overlap between oil and gas generation windows, but in general usually only the deepest, often most central, parts of sedimentary basins will be the source areas for gas accumulations. The exact depth depends on the type of source rock and the subsurface heat flow in the region. Seismic reflection imaging becomes increasingly difficult at greater depths, which creates more uncertainty in mapping the presence, and size, of potential gas traps.

The map use, though the best available, does not show the full extent of thick sedimentary rocks now known to be present in the Reinga, Deep water Taranaki, and Ruakumara basins. A revised map is in preparation at GNS Science.

The gas may have then migrated up-dip to shallower horizons, where it is either trapped or escapes to the surface. As another approximation, at least 1,000 metres of overburden is required above any possible hydrocarbon accumulation in order to provide enough compaction of capping sediments to provide an effective top-seal for the trap. Accordingly, a cut-off of 1,000 metre sediment thickness is defined here as the peripheral limit of possible petroleum occurrence (Figure 4.4.15). In other words, hydrocarbons might be found anywhere with sediment greater than 1,000 metres, provided that there is also a nearby “kitchen” area and suitable migration pathways in between.

Figure 4.4.15 - Gas generation potential

The regions for potential gas generation can be bounded by regions with sediment thickness between 5,000m (blue contour) and 6,000m.



4.4.2.3 Estimate of undiscovered reserves

There are several ways of estimating undiscovered reserves, none of which is robust in under-explored regions.

One method involves a Delphi analysis, or consensus expert opinion by several experienced petroleum geologists. This technique is simply a first-pass filter and is most useful for comparing the prospects of different basins or countries. Results can be quite varied, and are generally not based on detailed mapping of target structures.

A second method involves a statistical gap analysis, which predicts the sizes of missing (undiscovered) fields based on those that have already been found. The technique is based on the inference that the full, naturally occurring population of petroleum fields in a region will have a log-normal distribution.

A third method describes "creaming" curves, with the premise that the biggest fields are found early in the exploration cycle and smaller fields will only be found subsequently.

The only place in New Zealand where statistical analysis has been attempted is Taranaki Basin but, even here, a lot more drilling is required before statistically-based predictions of future field sizes are likely to be valid. Early predictions of future discoveries turned out to be too pessimistic, but were based on a very sparse data set.

The total Taranaki petroleum reserves discovered so far are roughly 11,628 PJ. Since the initial discoveries of Kapuni (1969) and Maui (1979), this total reserves inventory has been built up by punctuated, but steady, incremental additions. Based on the number of discoveries and cumulative reserve additions in recent years, one might predict that the next ten discoveries in Taranaki Basin would add about 1,836 PJ in new reserves volume. This assumes that exploration maturity has not yet reached the point of diminishing returns. Indeed, it also doesn't allow for radical geological paradigm shifts, technological advances, or drilling in the deep-water Taranaki Basin, all of which might result in one or more very large fields being found.

The most comprehensive quantification of possible future field sizes is based on detailed interpretation of seismic reflection profiles and derivative subsurface mapping of undrilled structures and stratigraphic traps. The result is the delineation of "leads" (trapping closures that are roughly defined with sparse data) and "prospects" (trapping closures that are relatively well defined with adequate data). Prospect mapping and evaluation is very time consuming. Companies generally only undertake this work within their exploration licence blocks and only to prioritise one or two prospects to drill. Even then, the predicted (pre-drill) volumes are fraught with assumptions and, time and again, have proved to be overly optimistic.

The amount of oil or gas in any individual structure, assuming adequate "charge" from source kitchens and effective sealing of cap rocks, depends primarily on the overall size of the structure and the thickness and quality of the reservoir.

There is no inventory map or comprehensive compilation of undrilled prospects in New Zealand. A few maps of undrilled structural closures, primarily within the Taranaki Basin, are available in government archives, having been lodged by companies upon the relinquishment of their exploration licence areas. The original maps of these prospects have not been verified since that time, and neither have the assumptions used for quantifying volumes of hydrocarbons within these structures.

4.4.2.3.1. Regional prospectivity

Taranaki Basin continues to be the focus for exploration in New Zealand, but other regions are also receiving attention. In the far, offshore, deep-water Taranaki Basin, and all other New Zealand basins, there are genuinely perceived geological prospects. Some significant, but uneconomic, discoveries have already been made that prove the existence of viable petroleum systems in other basins. In Canterbury, the Galleon-1 well produced a respectable 10 million standard cubic feet of gas per day (mmscf/day) and 2,300 barrels of condensate per day on test. In the Great South Basin, Kawau-1 flowed gas at 6.8 mmscf/day. In onshore East Coast basin, sub-commercial flows of gas were obtained from several wells in the late 1990s, and this remains a viable exploration area.

Most structures identified in our offshore regions are still delineated as "leads". Considerably more seismic data acquisition and mapping is needed to confirm their presence and to convert them to "drillable prospect" status.

4.4.2.3.2. Recent success rates

In the calendar years 2000 to 2005, a total of 149 wells were drilled, 69 of which were in the latter two years. Of the wells drilled, 74 were "wildcats", away from established fields. Twelve new discoveries were made, giving a statistical success rate of about 16%, or around one discovery per 6 wells [MED (2006)]. In this day and age, in which new discoveries are hard to come by globally, this is a very acceptable return. Even more significant is that, out of the nine wildcat wells drilled offshore in Taranaki during the 2000 – 2005 period, six were commercial discoveries. This bodes well for offshore exploration elsewhere in New Zealand.

4.4.3 Barriers and limitations

Historically, a global lack of demand for gas and a saturated local market have been impediments to gas exploration in New Zealand. These impediments have been removed with the decline of the Maui field, and because gas is rapidly becoming the thermal fuel of choice in many countries. The barriers to sustained production / growth of sector must consider both limits to exploration and development.

Gas exploration is very often constrained and influenced by government policies. On the one hand opportunities in oil and gas exploration are created by the release of licence blocks and new data. On the other hand, the government's climate change and energy policies influence industries' perception of the future cost of gas as a resource. At present, our local gas supply prognosis is only just sufficient to be able to defer investment in LNG import facilities in the near term. Because of its cost, an LNG terminal could only be justified if a long term take-or pay clause was included. This would have two immediate effects - cause a steep upward ramp in the price of gas, and discourage exploration and development of much lower cost local gas.

The development of resources in New Zealand is highly dependent on two factors:

1. Proximity to distribution infrastructure
2. Scale of the development

For small scale development the proximity to distribution infrastructure is the most limiting factor, since there is ample 'potential demand' for small scale production. For development which is located a considerable distance from current distribution infrastructure, the cost of transport to the network significantly affects cost of development.

The scale effects of large developments, means that a large portion of capital investment can be directed towards developing additional gas demand and / or distribution. If a major gas strike is made in the south of the country, there could be market or infrastructure barriers to development. If by then no significant new gas discoveries had been made in the north, then the main development constraints would be financial (due to the cost of transporting the gas north) rather than technical. If on the other hand the north was already well supplied as a result of new discoveries, then development of a major find in the south would probably be contingent on developing a local market (see Section 6 – Secondary conversion) in the south, or building an LNG export terminal. The latter would in itself be a financial decision, based on the global LNG market outlook, and transportation costs.

4.4.4 Introduction to conversion technology

The technology to refine oil, gas and condensate has undergone well over one hundred years of continuous development and, hence, can be considered mature. While gas processing and LNG technology has developed rapidly in recent years and is much “younger” than oil processing, gas technology can also be described as reasonably mature. The main technologies that combine together in order to realise the potential of subterranean gas resources are described under the following classifications:

- Gas production facilities
- Transportation of gas
- Gas utilisation
- Gas storage

4.4.4.1 Gas production facilities

Gas production facilities treat wellhead fluids, which often contain a mixture of oil, water, gas and impurities, and render them suitable for sale or for onward transmission for further downstream processing. In the case of gas treatment, the gas generally must be treated to national pipeline specifications. The specifications set criteria regarding the maximum concentration of contaminants (e.g. carbon dioxide, oxygen and inerts), as well the maximum concentration of heavier hydrocarbon species which affect dewpoint and ability to combust.

The primary separation step (shared with oil production) generally involves de-sanding (i.e. removal of solids) and initial separation of liquid phases from the gas phase. The resulting gas phase/s are most often chilled to drop-out heavier hydrocarbon species. The removal of gas phase contaminants is achieved through application of specific technologies relevant to each contaminant, for instance carbon dioxide can be removed with pressure swing absorption or membranes, whilst sulphur can be removed by passing the gas through a bed of iron oxide. The resulting gas must then be compressed back to pipeline pressure or liquefied (by refrigeration and compression) for LNG export.

The heavier hydrocarbon species are further treated – generally by a combination of flash and distillation separation – to yield LPG, fuel gas (i.e. butanes) and condensate.

4.4.4.1.1. Deep offshore and large onshore gas pathway

The extraction technology for deep offshore reserves is rapidly advancing, and water depths at which extraction is commercially viable increasing. Because the technology involved in this form of extraction is significantly more complex (e.g. floating production platforms with compression and refrigeration) than that required for medium / small onshore fields, the reservoir must be of significantly greater size (typically larger than 5,000 PJ) in order to be commercially viable.

The cost and location of: wellhead fluid extraction; wellhead fluid transportation, primary hydrocarbon gas / liquids and water separation and product storage are all considered collectively on a reservoir by reservoir basis. Some developments are most cost effective with extraction and gas processing occurring offshore, with gas distributed to shore by pipeline; conversely other developments extract wellhead fluids to onshore processing facilities.

Fixed offshore production facilities consist of topsides and support structure (i.e. jacket). The design and cost of offshore production facilities in New Zealand are controlled by three main factors:

1. Weight of the "topsides" processing plant - The weight and, hence, the cost of the topsides is primarily determined by the oil throughput volumes, with processing complexity a further factor.
2. The water depth - The weight and cost of the support structure is principally determined by the water depth and with topsides weight being an important secondary factor.
3. Mobilising offshore work barges - This factor particularly applies to remote regions, like New Zealand where the price tag for barge mobilisation is in the range of US$20 – 25 million. There is ample incentive for inventive solutions that avoid a work barge. Some are based on utilising the drilling rig - which must be mobilised anyway.

Over recent years there has been a concerted effort to reduce the cost of offshore production facilities. This has resulted in a major rethink on all aspects of offshore processing and manning, with the result that every effort is now made to transfer as many operations as possible from offshore to onshore. As a consequence, many offshore platforms are now little better than wellhead or drilling / work-over platforms, and designed for minimal or intermittent manning at the most.

Current practice is, where possible, to avoid offshore processing - with the exception of facilities for cleaning of pipelines, and the injection of chemicals to avoid pipeline problems – by running mixed phase, "wet gas" lines to shore. This avoids the weight penalty of offshore separation and utility equipment. Pipeline corrosion, wax and hydrate problems are addressed by use of speciality chemicals and careful metallurgical selection. These minimal wellhead platforms provide only sufficient "dry real estate" to allow intermittent operator access to the wellheads, and the chemical injection points. By running "piggy back" lines alongside the main production flow line to shore, all chemical storage and injection equipment can be located onshore.

The quality of the separated gas defines what level of subsequent processing is appropriate. If the gas is "rich" then condensate separation will support the economics of the development. If the gas has high CO_2 content, then much of this contaminant must be removed. Water content in the gas must also be controlled – as fields age, generally more water will need to be removed. The resulting gas is then compressed for distribution to demand centres via the national gas grid.

Storage to accommodate variability in supply and demand is generally provided by line-pack (changing pressure) in the distribution grid. In some countries, additional storage is provided in underground gas reservoirs. Contact Energy hopes is developing New Zealand's first underground gas storage facility at the depleted Tariki / Ahuroa field.

4.4.4.1.2. Medium / small scale onshore gas pathway

The extraction and processing technology for medium and small scale onshore reserves is essentially mature, with some advances in horizontal drilling and CO_2 separation resulting in greater cost effectiveness. Dependent on quality of gas and proximity to the national gas grid, reserves as small as 20 PJ may be developed.

Gas processing requirements for these developments are similar to the large fields addressed above, i.e. condensate separation; CO_2 reduction and dehydration. The extent of each separation will depend on the demands of the gas user and capability to blend with other gases in the distribution network.

Figure 4.4.16 – Image of 'typical' medium scale gas processing plant

4.4.4.2 Transportation of gas

Natural gas can be quite difficult to transport since it must remain contained and is low density under ambient conditions. The preferred mechanism of transport changes with volume and distance. The transport of low volumes of natural gas over short distances (i.e. <50 km) can be achieved by trucking of pressurised gas contained in bottles or tanks.

The vast majority of gas transport is achieved with pressurised (~30 bar) pipelines. If buried, pipelines are literally invisible once grass cover has re-grown. The majority of pipelines in

Taranaki cross privately-owned farm properties and, in most cases, owner pipeline consents follow the agreement the oil industry negotiated with Federated Farmers.

To transport gas a distance greater than 2,000 km, the refrigeration of compressed gas should be considered. Although refrigeration is relatively expensive, the resulting increase in density significantly reduces transport cost. The advent of compressed natural gas (CNG) shipping and LNG tankers greatly increased the capacity for the international trade of natural gas.

4.4.4.3 Gas utilisation

The common uses of natural gas were identified in Section 4.4.1.4.3. Reviewing the conversion technology that under-pins each of these uses is beyond the scope of this project, however it is valuable to realise that if New Zealand did not have any utilisation infrastructure then there would be no demand.

A little over thirty years ago there was little demand for gas world wide; and hence gas was regarded as an inconvenient waste product, and flared. This situation has changed remarkably, to the point that natural gas is a considered a highly valued commodity. The change resulted from developing technologies which could utilise gas to yield tradable commodities. Some of the conversion technologies that have been developed include:

- Haber Bosch – used to yield fertiliser
- BASF / ICI methanol synthesis - used to yield methanol
- Indirect (e.g. Fischer-Tropsch) and direct (e.g. Mobil) GTL – used to yield synthetic fuels e.g. petrol, diesel
- Polymerisation - used to yield plastics

The sale of gas-derived products plays an important role in supporting the growth of the New Zealand economy e.g. fertiliser production displaces imports; CNG use in vehicles displaces imports; methanol is a valuable export product.

In the future, other products may play an equally important role e.g. fuel cells for local electricity generation, gas to liquids technology for petrol / diesel production; LNG exports and plastics exports.

4.4.4.4 Gas storage

The traditional mechanism for balancing gas supply with gas demand involves:

1. Only produce gas when needed i.e. the raw gas reserve provides storage,
2. Reducing pressure in transportation pipelines i.e. ‘line pack’ provides a minor volume of gas storage.

When the demand rate for gas varies faster than be accommodated by gas processing plants, storage of sales gas is required, either in depleted gas reservoirs or in storage tanks.

Since pressurised gas has a relatively low density, it is not cost effective to store gas in tanks at ambient conditions, hence refrigeration is required. The storage conditions generally reflect those of the two typical transport mechanism:

- LNG storage is based on heavily insulated, double contained tanks constructed from high nickel steel and operating at -160°C.
- CNG storage is based on heavily insulated steel pressure vessels operating at 80 bar and -30˚C.

4.4.4.5 Technology direction

New technology for offshore production of LNG from floating facilities is on the horizon and, once established, should have huge implications for the viability of future gas discoveries in New Zealand. A Norwegian company is currently constructing three special purpose-built LNG carriers in Korea with topside facilities for pre-treatment and liquefaction of natural gas (EnergyReview.net, 11 February, 2008). Each vessel will be able to produce at least 1 million tonnes a year of LNG, and the ships will be ready for first LNG production by 2011.

These ships are equivalent to FPSOs that are currently used for oil production. The vessels would be able to transport the LNG they produced themselves, or transfer the liquefied gas to standard LNG tankers.

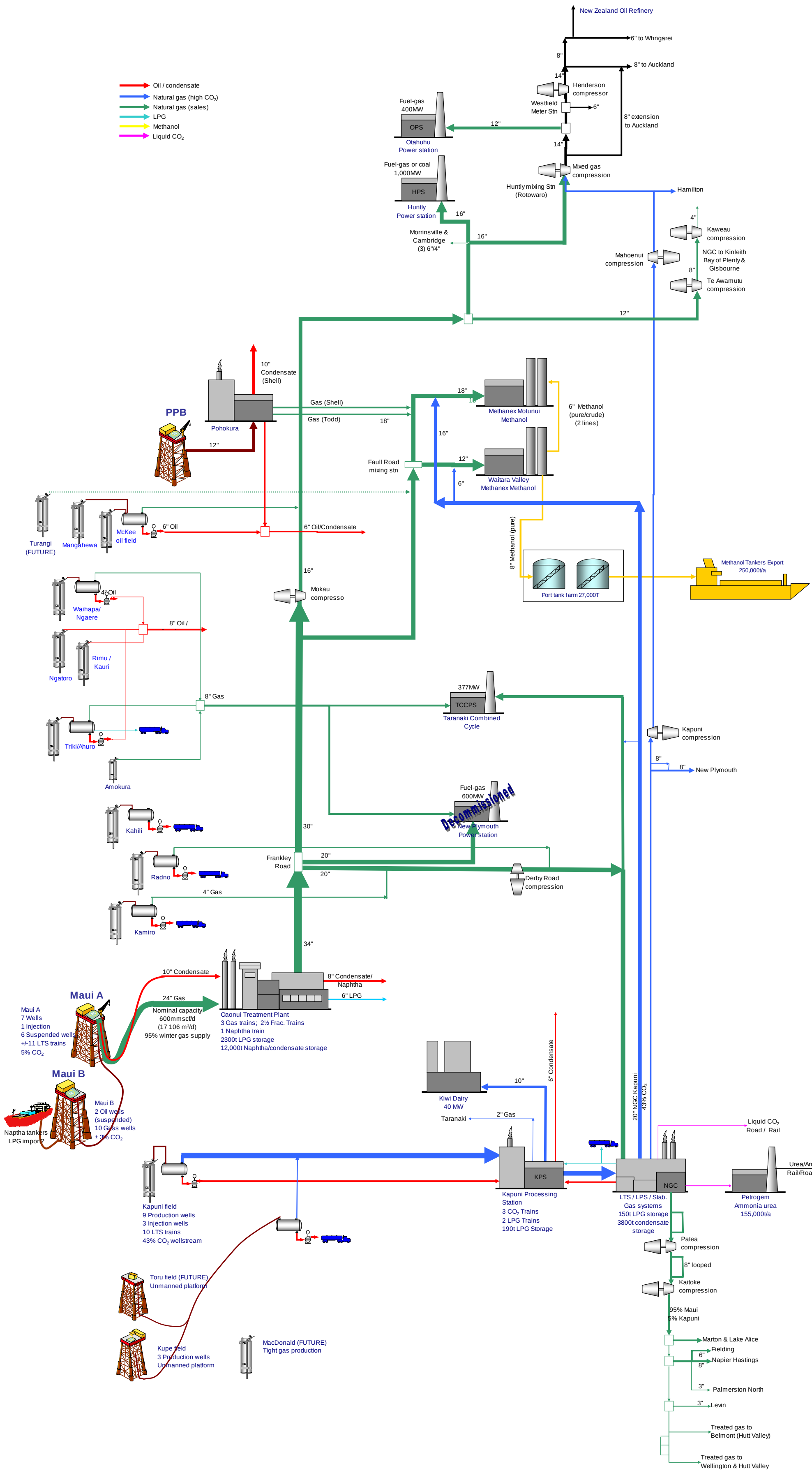
The technology will allow the development of gas fields that are too small to justify an onshore LNG facility. It could also entice mid-sized companies to explore offshore. Although they might be looking for oil, any moderate-sized gas find could be developed, without the need to finance a large onshore facility. Whereas standard LNG operations need fields with at least 5,000 billion cubic feet (4,850 PJ) of gas, the new technology would allow development of gas fields one tenth that size (EnergyReview.net, 11 February, 2008). The technology would expedite the development of larger fields, to take advantage of favourable market conditions and to generate early cash flow in advance of any onshore development.

Recent advances in small and household scale combined heat and power systems have finally brought this technology to the point of commercial reality. Reliable, local generation at this scale has the potential to significantly improve our society's energy efficiency, and reduce reliance on the electricity grid. The two technologies that have been competing in this space are:

- Closed circuit vapour turbogenerator (CCVT) e.g. Whispertech, Ormat and,
- Natural gas fuel cells e.g. FuelCell Energy, Bloom Energy, Ceres Power, ClearEdge and Panasonic.

For more detail on combined heat and power systems please refer to Section 6.4.4.

Figure 4.4.17 – Schematic of New Zealand gas assets



An A3 version of this figure is provided in Appendix A.

4.4.5 Asset characterisation

The cost of developing gas assets varies considerably in response to: field risk, field location, reservoir quality and size, the envisaged production time frame etc. Furthermore the global gas service sector often experiences cyclical boom and bust periods. This leads to periodic inflation and deflation in the cost of gas development services and equipment.

4.4.5.1 Gas extraction facilities

Gas extraction facilities are generally considered to be an extension of the gas processing plant. For medium and small gas production plants, the technology is generally fairly simple, with construction timeframes similar to that of the production plant. For deep offshore and larger gas production facilities, the technology may be considerably more complex (e.g. subsea completions and tie-ins), but is still considered an extension of the production plant.

The cost of onshore or near-shore / shallow water gas extraction facilities is relatively trivial compared to the cost of exploration and drilling. The costs of these facilities have either been lumped with the gas production facilities or are a small fraction of the production facility costs – see Table 4.4.18.

Once a well is in production, the only GHG emissions are those associated with leaks and emergency flaring. These 'fugitive' emissions are generally less than a few percent of the production rate.

Table 4.4.18 – Typical benchmarks for costing gas production assets

155 Sm^3 gas is equivalent to 1 bbl of oil

Description	Drillex US$/boe	CAPEX US$/boe (reserves)	OPEX US$/boe
Onshore production plant	2 to 5	0.5 to 2.5	3 to 4
Wellhead platform (<30m water) Production platform (<30m water) Deep water	2.5 to 5 + Rig mob/demob 2.5 to 5 + Rig mob/demob No data	NZ$50 million 1.5 to 4 + Barge mob/demob No data	3 to 4
Floating LNG plant*	No data	No data	No data

* - Assuming ownership rather than leasing.

4.4.5.2 Gas production facilities

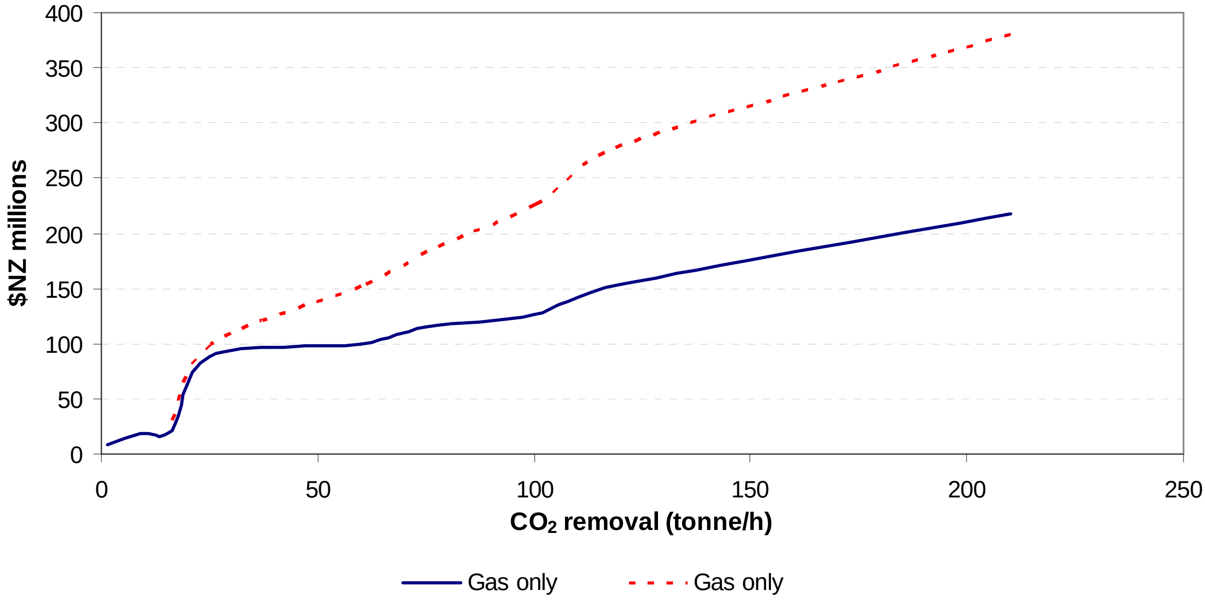
The production facility cost benchmarking which considers CAPEX and OPEX in terms of "total recoverable" reserves (see Table 4.4.18) only provides an indication of gas production facility costs. The table illustrates that offshore production facilities are considerably more expensive than onshore facilities, but the cost range for topsides (i.e. gas processing equipment cf. structure to support this) varies considerably, as explained below.

The cost of gas processing equipment is dependent upon several variables, namely:

- Pressure of the source reservoir - The pressure of reservoir influences what dewpoint control technology can be used, and how much compression is required.
- Volume of associated light liquids - If there are sufficient associated light liquids (i.e. LPG) in the raw gas, then an additional separation train will be required.
- Quality of raw gas - For many raw gas streams (e.g. Maui), there is little need to remove contaminants (such as sulphur and carbon dioxide), for other plants (e.g. Kapuni raw gas is 45% CO_2) the cost of contaminant removal is significant.

Since most gas reserves in New Zealand have good water drive and adequate pressure, some generic CAPEX curves can be ascribed to typical gas production facilities[16] - see Figure 4.4.19.

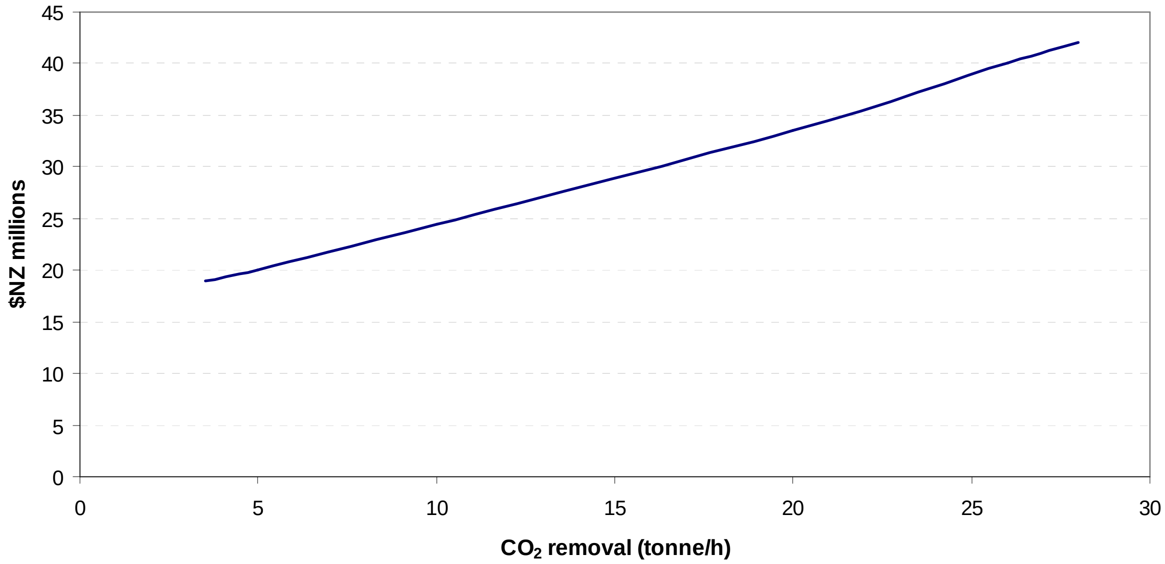
Figure 4.4.19 – Typical New Zealand gas processing plant CAPEX



The design of CO_2 removal plants is dictated both by the quantity of CO_2 removed per hour, as well as the total gas flow processed. Figure 4.4.20 provides indicative CAPEX costs for New Zealand CO_2 removal facilities. There is a significant fixed cost element to CO_2 removal plants (i.e. the intercept at zero looks to lie somewhere between \$15 and \$20 million). Thus, at low levels of CO_2 removal there are significant economies of scale, but these disappear at levels above five tonne per hour. It should be noted that this cost is considered as an addition to an existing gas plant cost (i.e. not on a standalone basis), because there are many common shared facilities / utilities between a CO_2 removal plant and the associated gas plant.

[16] Onshore plant with no carbon dioxide removal or inlet compression.

Figure 4.4.20 – Typical CAPEX for CO_2 removal plant

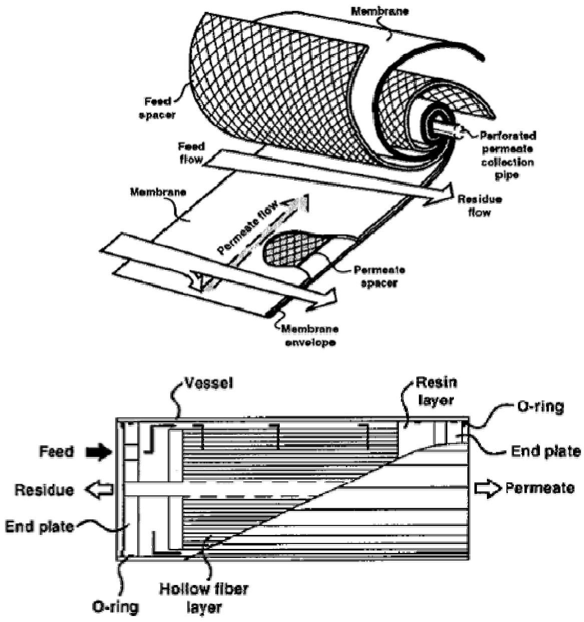


By linking the information in Figure 4.4.19 with Figure 4.4.20, it is possible be identify how the CO_2 removal costs influence the overall gas plant CAPEX.

Table 4.4.21 – Influence of CO_2 removal on gas plant CAPEX

		Gas Plant Size		
		60 PJ/y	75 PJ/y	100 PJ/y
CO_2 Removal	10 tonne/h	26%	23%	21%
	18 tonne/h CO_2	34%	29%	26%
	25 tonne/h	41%	35%	32%

Figure 4.4.22 – Image and schematic of membrane based CO_2 removal plant



Source: Image - UOP Separex Membrane system
Schematic – Baker, 2002

Since New Zealand has relatively few production facilities, it has been possible to obtain actual construction costs (or cost estimates) for the majority of assets – see Table 4.4.23.

Table 4.4.23 – Capital cost of New Zealand gas production assets

Asset	Commission date	Capital cost (NZ$ million, 2007)
Kapuni – gas / condensate field	1962	≈2,200
Kapuni - Gas Treatment Plant	1969	
Maui A – Offshore platform	late 1970s	≈7,600
MPS - Maui Production station	late 1970s	
Maui B project	1992	1,000
Pohokura	2006	900
Kupe	2009	~900

The timescale to build a production facility depends on the size and complexity, but three to five years is typical. Bringing offshore discoveries into production takes a year or two longer. The following times are typical for various phases of project development:

i) Option elimination, and definition of preferred development plan: 18 months

ii) Consents: approx 12-18 months, partly concurrent with i) above

iii) Design and procurement: 12-18 months, partly concurrent with ii) above

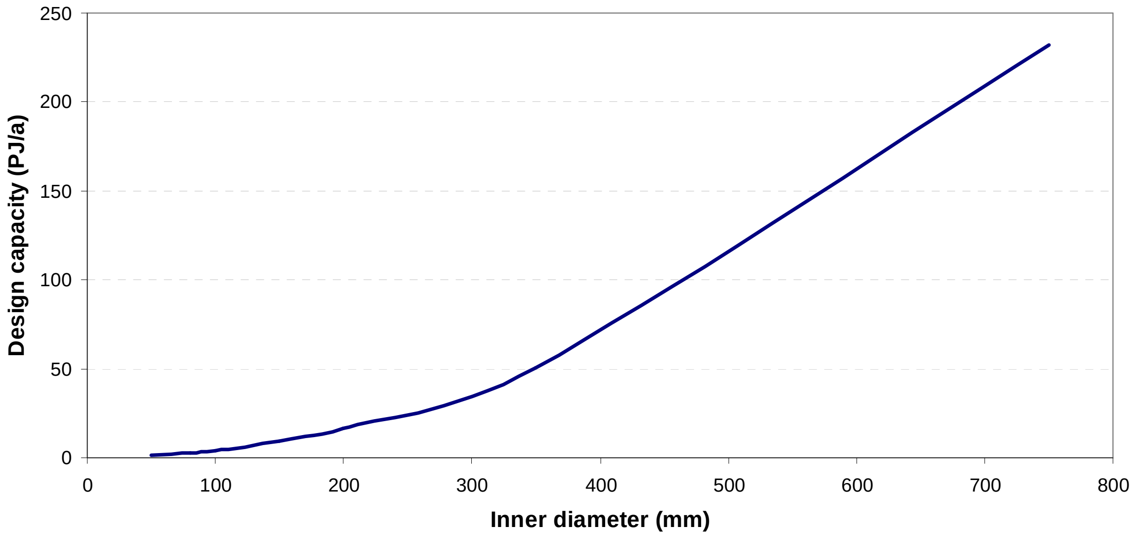
iv) Construction: 18-24 months, partly concurrent with iii) above

The field life of gas reserves is dependent on the size of the discovery and rate of extraction. The extraction rate is often dependent upon field pressure and declines towards the end of field life. Generally the supporting infrastructure is designed for a life of between 25 and 30 years, with major overhauls after about 10 years. The constant process of plant renewal and modifications means that in reality many plants can have a life in excess of 30 years e.g. Kapuni Gas Treatment plant.

4.4.5.3 Gas transport assets

The primary mechanism for transporting gas is via pipelines. The gas carrying capacity of pipelines follows a squared relationship with diameter for a inlet pressure condition. Figure 4.4.24 indicates the relationship between pipeline diameter and maximum flowing capacity, assuming: typical processed gas to NZS 5442, 53 bar inlet pressure, 25 km carbon-steel pipeline length, 10 bar pressure drop across the pipeline.

Figure 4.4.24 - Gas transmission pipeline capacities



In order to obtain a first pass, "high-level" order of cost for such pipelines, the following simple formula is often applied.

Installed pipeline cost = (L × D × m) + X + V + C + M

Where:

- L = pipe-line length in km
- D = pipe diameter in inches
- m = is a pipe length-diameter cost factor (see Figure 4.2.18)
- X = fixed NZ$ cost per crossing
- V = fixed NZ$ cost per valve stations
- C = Cost of compression stations
- M = Pipe-lay barge mobilisation cost (for offshore pipelines)

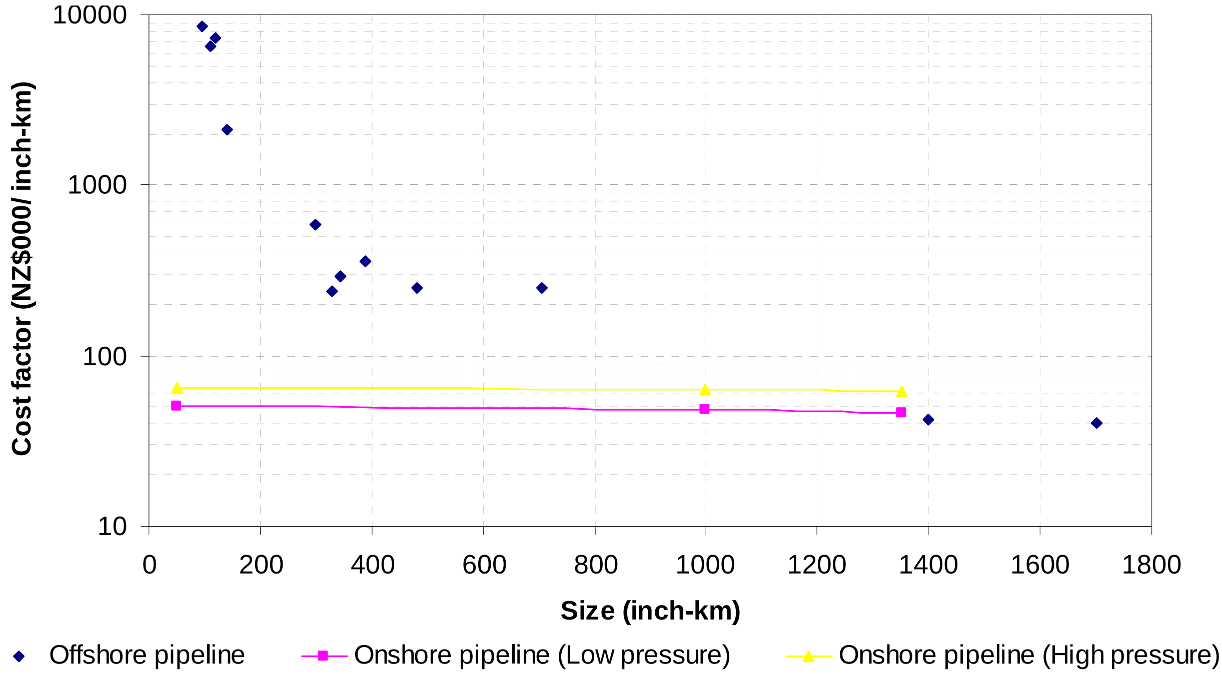
This formula is reasonably applicable for carbon steel pipelines in the size range of 4" – 16", which traverse relatively easy open terrain. The formula allows for consents, easements, materials, construction plant and labour, engineering design and supervision. Higher pipeline cost factors should be applied to pipeline laid in difficult (steep and rugged) terrain, and pipelines constructed from exotic materials.

The costing of onshore pipelines is relatively straight forward application of the pipeline cost factors summarised in Figure 4.2.18. The cost of crossings can vary from, approximately; $10,000 for crossing a rural road; $25,000 for crossing a creek; up to $250,000 for crossing rivers or major obstacles. Any horizontal directional drilling or valve stations need to be costed separately, as these can vary considerably depending on terrain and line size.

The cost of compressor stations must be estimated separately. For gas turbine-driven compressors, the cost of the rotating machinery (approximately $1,000/MW) makes up approximately 40% of the cost of the complete station.

In the event that a major gas discovery is made in the south, the cost of connecting it (including compression) to the North Island gas grid with a 20 - 24 inch diameter pipeline can be expected to be in the order of NZ$1.6 million / km for the onshore section, and NZ$3.3 million / km for the offshore section.

Figure 4.4.25 – Pipeline cost factor (NZ dollars, 2007)



The cost of offshore pipelines can be estimated using the above formula, but since New Zealand's our meteorological-oceanic conditions are onerous, construction costs can be significantly higher than predicted by the simple formula. For offshore pipelines it is also necessary to determine pipe-lay mobilisation costs. There are basically three options:

1. Conventional pipe-lay barge mobilisation – Often in the order of $20 – 30 million. Currently worldwide supply of these barges is tight.
2. Modified light vessels to commission bottom tow or flexible / reeled pipeline designs. This option can be attractive because it obviates conventional barge mobilisation costs.
3. Work barge mobilisation - For some offshore jobs where heavy platforms and topsides need a work barge, the mobilisation costs can be spread over both conventional work and pipe-laying.

4.4.5.4 Gas utilisation

Since New Zealand has relatively few gas utilisation facilities, it has been possible to obtain actual construction costs (or cost estimates) for the majority of assets – see Table 4.4.23.

Table 4.4.26 – Capital cost of New Zealand gas utilisation assets

Asset	Description	Output capacity (PJ/y)	Consumption capacity (PJ/y)	Commission date	Capital cost (NZ$ million, 2007)
New Plymouth power station	Open cycle gas turbine (450 MW; Decommissioned)	14.2		1970's	900 (= 2007 est)
Taranaki CC	Combined cycle gas turbine (377 MW)	12.1	21.9	1998	
Maui Development pipe line & North Island gas grid	Electricity generation and co-generation Petrochemical industry Commercial use (incl. CNG transport use) Residential use Industrial use		86.4 28.7 3.5 4.3 31.0	1970s	1,000 (= 2007 est)
Kapuni Ammonia Urea	NG to Ammonia / urea (479 tpd → 155 ktpa)	Non-energy	7.8	1981	120
Methanol Waitara valley	NG to methanol plant (1,800 tpd → 530 ktpa)	10.80	20.0	1982	250
Motonui methanol & methanol to gasoline	NG to methanol plant (2@2,600 tpd → 2@ 1,200 ktpa) Methanol to gasoline plant (2,200 tpd; demolished)	36.8	68.1	1983	3,000
Port Taranaki	Urea/LPG/MeOH loading (Not used)			1982	25
Huntly 1-4	Open cycle gas turbine – coal and gas (972 MW)		5 PJ/y auxiliary	1980's	1,950 (=2007 est)
Huntly 6 (P40)	Open cycle gas turbine - gas	1.6	6.0	2004	
Huntly e3p	Combined cycle gas turbine	12.1	21.3	2007	
Stratford power station				1990's	350 (= 2007 est)
Otahuhu B	Combined cycle gas turbine	12.7	24.4	1999	400 (= 2007 est)
Southdown cogen	Hybrid CC – cogen plant	3.8	8.8	1997	
Orica (Morrinsville)	NG to hydrogen peroxide	Non-energy	0.9	1983	

The time taken to develop gas assets is considered to be:

- Consent: approx 2 years
- Research: approx 1-2 years
- Construction and finance: approx 2 years

The operational lifespan of an asset is typically around 30 years. The design asset life is normally quoted to be between 15 - 25 years, with major overhauls after approximately 10 years.

Gas generally produces lower levels of pollution than other thermal generation fuel sources (both in terms of noxious pollutants and CO_2 per unit of energy produced). Whereas coal produces around 91 kt CO_2/PJ, gas (from Maui for example) produces almost half of this amount at 52 kt CO_2/PJ. Kapuni gas is an exception – because the CO_2 stripped from Kapuni gas is vented to atmsopher, the CO_2 emissions from Kapuni is comparable to that of coal. Depending on the technology used, gas is generally a more efficient fuel. For example, coal fired thermal generation is generally has a transformation efficiency in the region of 35%, compared to modern combined cycle gas turbines which may have efficiency factors of greater than 60%.

4.4.5.5 Gas storage

New Zealand only has one gas storage facility – the Ahuroa field, owned and operated by Contact Energy, will be able to withdraw gas at rates up to 170 TJ/day. The total investment in this infrastructure was $150 million[17].

The rule of thumb for costing LNG storage tanks is NZ$3,700/m³, but the cost of high nickel steel has seen dramatic cost increases recently. Two 240,000 m³ tanks would be suitable to support a 100 PJ/y import / export terminal.

4.4.5.6 Present and future gas supply costs

Gas pricing is different to oil, in that while oil is easily stored, easy to transport, and has a high volumetric energy content, exactly the opposite applies to gas. For this reason, until large gas markets opened up, produced gas was considered a nuisance and flared.

When the Maui gas / condensate field was discovered, total gas demand in New Zealand was insufficient to make development of the reserves worthwhile. Security for the development of Maui field gas was assured by the government signing the Maui White Paper which established a take-or-pay contract with the Maui partners and Shell, as operator, developed the field.

Until recently the price of gas in New Zealand was determined by the escalation formula in the Maui White Paper. In 2001 Maui wellhead gas was NZ$2.2/GJ - the cheapest in the world. Subsequent depletion of the Maui reserves has lead to industrial gas prices rising towards NZ$7.8/GJ. Local gas prices reflect the costs required to supply local demand. If LNG imports were required to support local demand, then gas prices will likely rise above NZ$12/GJ.

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[17] Ahuroa facility development costs were: $27m for the rights to use the site, $27m for the remaining gas in the storage, $54m for gas inventory, and $150m for processing infrastructure (http://nzenergy-environment.co.nz/home/free-articles/taranaki-gas-storage-facility-on-track.html).

The MED reference scenario now defines the gas price outlook as “existing plants are assumed to be able to access gas a prices of $8.5/GJ (in real terms) until ~2020. Post 2020, tightening supply sees gas prices begin to rise gradually towards the opportunity cost of alternative energy sources for electricity generation of ~$13/GJ (including emission pricing) by 2035”

4.4.6 Research status

“Applied research” that furthers the understanding of New Zealand’s petroleum potential, and develops a broad nationwide inventory of petroleum prospecting leads and concepts, has the potential to increase petroleum exploration and subsequently improve the national trade position. This type of research is beyond the mandate of private companies, who are focused on detailed mapping of their licence areas, and consequently must be undertaken by governments or national petroleum companies. New Zealand’s understanding of petroleum potential is relatively immature, hence there are several research areas which should be considered:

1. Undertaking sediment and structure mapping of frontier regions - the cost of this data acquisition and interpretation is non-trivial (in the order of $50 million over the next decade).
2. "Next generation" regional digital maps of basin depositional systems and structures using industry-standard state-of-the-art techniques. To “fast-track” the digital mapping of say 5 basins over the next 10 years would require about $2.5 million per annum.
3. Aggregation of exploration leads and prospects. The Crown Minerals archives contain an enormous amount of historic exploration and leads data from petroleum company mapping of licence areas. Significant value could be derived from systematic nation-wide compilation of the relevant ‘open file’ data.
4. Developing innovative exploration play concepts, including for deep gas and stratigraphic traps which could be very big but which have hitherto received little attention.

New Zealand contributes little to the development of oil and gas technology advances but can still benefit from changes as they occur. For example, advances in sub-surface imaging and computer technology has enabled exploration in new areas in deeper water. The advent of “geo-steering” and horizontal drilling has allowed production wells to penetrate much more of the reservoir target, thus enhancing ultimate recovery. The uptake of other technology, such as the use of floating LNG production and off-take vessels may facilitate the development of offshore gas fields without the need for pipelines to shore-based production stations.

The national benefit that results from petroleum exploration and development is set by the associated rules and regulations. In order to ensure that the nation derives maximum benefits from such developments, there is a need for strategic analysis of national policy and strategy. The review should consider:

- The impact of environmental taxes on trading relations e.g. carbon tax on imported products.

- The economic impact of paying a premium for domestic fuels relative to imported fuels - Money spent domestically has significant kick-on effects associated with provision of services and reduced sensitivity to the dollar market.
- The role of demand side management and energy supply substation (e.g. gas to liquids plant).
- The importance of national dialogue and acceptance of resource exploitation strategy, with particular focus of the role of revenue reinvestment.

Table 4.4.27 – Research status

(Green highlight indicates 'Fair knowledge', Amber indicates 'Could improve', Red indicates 'Knowledge gap exists')

	International	New Zealand	Comment
Develop a strategic picture to assess risks / responses to volatility in gas availability / affordability, and economic impact of indigenous production Vs import.	Advancing Government bodies	Immature MED, Treasury, Consultants	There have suggestions that a "Petroleum strategy development" advisory board be established with a mandate similar to the former "Liquid Fuels Trust Board".
Quantification and qualification of basin structure, volumes and type of sediments and assessment of petroleum prospectivity in far offshore frontier areas	Advancing. Petroleum industry. Other Government agencies such as CSIRO, AGSO, USGS	Immature GNS, Crown Minerals	Acquisition and interpretation of offshore geophysical and remote sensing data to identify possible petroleum exploration plays. Primarily seismic reflection data, but also including gravity, magnetic, and geochemical sniffer surveys.
Quantification and qualification of structure and volumes and type of sediments in proximal frontier basins with known but as yet uneconomic petroleum potential (i.e. excluding Taranaki Basin)	Advancing. Petroleum industry. Other Government agencies such as CSIRO, GA, USGS	Advancing. GNS, Crown Minerals	"Next generation" state-of-the-art digital mapping of basin depositional systems and structure from seismic reflection data, for input into sophisticated models of petroleum generation, migration and likely present-day habitats.
Aggregation of existing un-drilled exploration leads & prospects and identification of new potential targets	Advancing, Petroleum industry Other Government agencies such as CSIRO, GA, USGS	Immature. Crown Minerals, GNS	Compilation of un-drilled leads and prospects previously mapped by oil companies, with associated metadata, supporting information and verification, including names, location, target horizons and estimated reserves volumes. Development of innovative exploration play concepts, including for deep gas and stratigraphic traps, and petroleum charge scenarios.

Maximising production from discovered fields (recovery efficiency)	Advancing, Petroleum industry, Other Government agencies such as CSIRO	Advancing. GNS, UoA	Applied reservoir quality characterisation through petrology, petrography, diagenesis, rock property and stratigraphic architecture studies, for input into production simulation models.
Petroleum systems geoscience	Advancing, Petroleum industry, Other Government agencies such as CSIRO, GA, USGS	Advancing. GNS	Increasingly specialised determination of geological factors that are critical for petroleum charge, re-migration and accumulation. Some data shortfalls include: seal rock properties, structural controls on fluid migration, geochemical correlations between source rocks and produced oils, empirical reservoir properties, controls on reservoir quality by depth, area and geological formation, analysis of paleo-oil accumulations, effects of tectonics on subsurface stress and fluid pressures.
Petroleum geoscience databases	Advancing, Petroleum industry	Advancing. Crown Minerals, GNS	Sophisticated data compilation and interpretation products, and digital data delivery mechanisms, especially in GIS (map-referenced) format. There is exciting potential also for presenting data in 3D visualisation models.
Drilling	Mature	Mature. Oil industry	Drilling many wells is the number one requisite to make new discoveries, but drilling research per se is not required.
Processing technology	Mature. UOP	Mature. NZRC, Transfield Worley	R&D is being done internationally.
Gas storage	Advancing, Petroleum industry	Immature Contact Energy, GNS	Geological evaluation of depleted gas reservoirs as future strategic storage sites, potentially in synergy with CCS.
Deep gas	Advancing, Petroleum industry Other Government agencies such as USGS	Immature	Investigate reservoir quality versus depth trends, pressure and stress regimes, fault behaviour, potential for basin centred gas, close to source reservoir distribution and play concepts
Petroleum price forecasting	Immature	Immature. MED, NIWA, Solid Energy	'Active following' requires an annual budget to be allocated to the task.

4.4.7 Summary

For countries seeking to reduce GHG emissions and increase energy system resilience, the qualities of natural gas have great appeal. Natural gas has the lowest GHG emissions of all fossil fuels, and yet is still a relatively cheap fuel. It is therefore an ideal substitute for coal as a fuel for heating and electricity generation. The flexibility of natural gas means that it can substitute oil as a transportation fuel.

The backbone of New Zealand's gas infrastructure was constructed as a response to the world oil shocks of the 1970s. Government advisors recommended converting some of the huge Maui gas reserves into liquid transport fuel, in an effort to insulate the country from high world oil prices. This materialised during this 'Think Big' era, when government initiative and sponsorship lead to the development of: Motunui (methanol production + gas to gasoline), Waitara Valley (methanol production), Kapuni (ammonia-urea manufacture). The Motonui methanol to gasoline plant was decommissioned and demolished in the mid 1990s, but the gas to methanol train still continues to produce chemical grade methanol for export.

New Zealand has historically had a more than sufficient gas supply from Taranaki fields, particularly Maui, which has seen gas grow to account for around a fifth of total electricity generation. The re-determination of Maui reserves marked a significant change in outlook – even with a significantly reduced demand from the petrochemical industry, the potential for a gas supply shortfall is on the near (<10 years) horizon. New Zealand currently has a limited appetite for developments that require a natural gas feedstock, and the associated economic opportunities. Greater recognition of the huge economic benefits of the development of large petroleum discoveries could dramatically change this outlook.

New Zealand's distance from global markets effectively places a surcharge on our trading margins. To counteract this, we need to reduce the economic cost of every input of production to less than that of our trading partners. This includes the cost of energy, which in turn means we need to utilise the cheapest, most efficient, and most flexible fuels available. New Zealand is obliged to follow the preferred global trend of exploiting gas, if for no other reason than to stay competitive in the international marketplace.

New Zealand must be prepared to explore the opportunities associated with large scale gas field development or else face continued erosion of its' economic base. Medium scale development will only support domestic energy (e.g. electricity generation, fertiliser manufacture), but will not enable development of export markets (e.g. methanol, LNG) or provide transport fuel resilience (e.g. CNG, GTL). At current market rates ($12.2/GJ) a field the size of Maui (4,050 PJ) is worth approximately $49.5 billion. This resource helps to underpin electricity generation, has value for direct heating use, and is a critical feedstock for fertiliser and methanol production (the latter being a significant export earner). In 2003 it was forecast that the loss of "cheap" Maui gas would cost the economy at least an extra $220 million a year for alternatives and, if less palatable options such as importing LNG or coal are adopted, the incremental cost could exceed $1,000 million (Stone, 2003).

If New Zealand does not respond strategically, there is a risk that we will resort to LNG importation with subsequent damage to our economy. The irony is that New Zealand has reason to be optimistic about its gas supply future, since it has vast, relatively unexplored, offshore territories within which there remains significant potential for world-class gas fields to be found (with associated export earnings). For the full economic benefits of this to be realised, a sustained and thorough investigation of our petroleum resource potential is required. It could be an opportunity missed if, say in thirty years time, politicians and consumers alike were asking “I wonder if we do have large petroleum fields out there?”

Ultimately, New Zealand’s strategic approach must remain cognisant of the long lead times associated with petroleum field research, exploration, discovery, and production processes. Maintaining underlying economic prosperity will require continued research, support and reinvestment of revenue streams. Making a step change in economic performance, or responding to the threat of supply – demand tension, will likely require government intervention and more regulation in the domestic petroleum market.

Section 4.5
Unconventional gas

4.5 UNCONVENTIONAL GAS RESOURCES

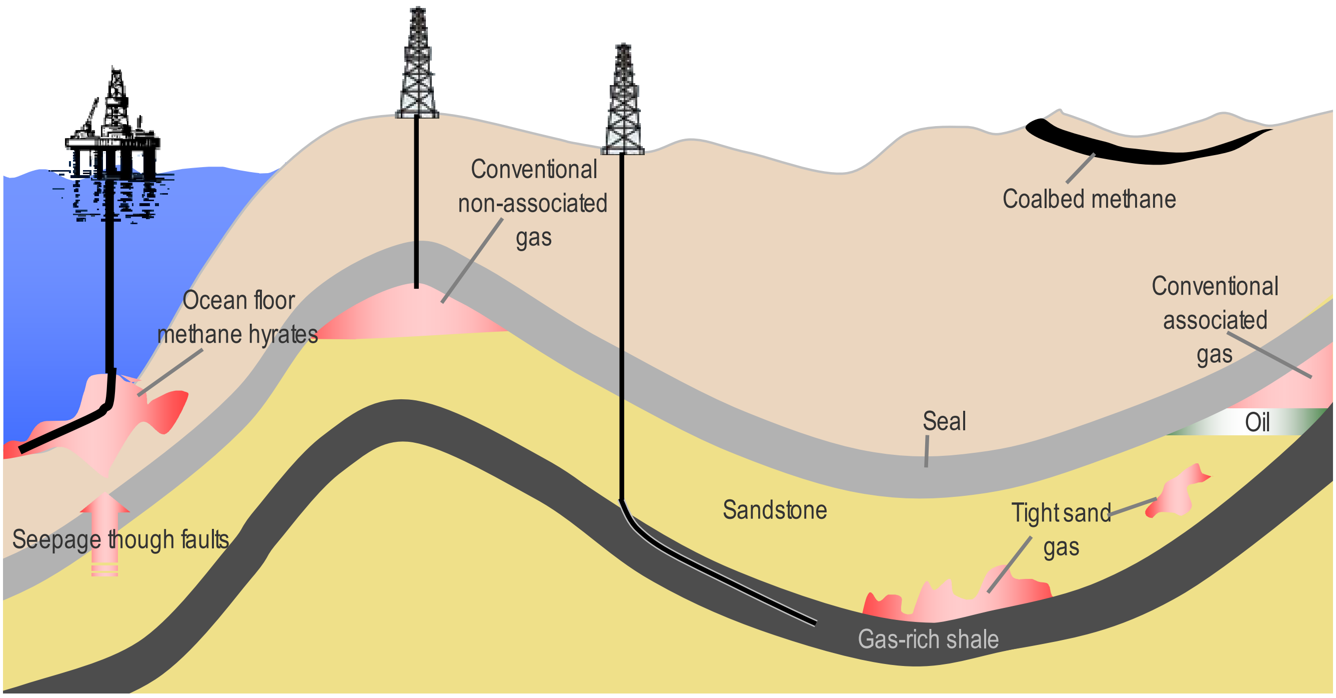
4.5.1 General introduction

> Unconventional gas resources can be characterised by:
>
> - Immature, but rapidly advancing extraction technology
> - Environmental impacts not well understood

The distinction between conventional and unconventional gas resources is a convenient way of distinguishing between traditional and possible future resources extraction opportunities. Historically, natural gas has been recovered from traps[18]. This "conventional gas" has migrated from source rock to the reservoir. In contrast, "unconventional gas" has either not migrated from source, or is held in location by association with the source material. In order to extract this gas, the bond between source material and gas molecules must be overcome. In this section we consider four forms of unconventional gas resource:

- Coal bed methane (CBM) adsorbed into the coal matrix
- Tight gas held in source roack
- Shale gas held in mudstone beds
- Methane hydrates held in solid form at depth by pressure

Figure 4.5.1 – Schematic of unconventional gas geology



Source: Adapted from http://en.wikipedia.org/wiki/File:GasDepositDiagram.jpg

[18] A structure in the earth's crust where a non-permeable layer (seal) over-lays a porous / permeable layer of rock. Structural traps result from deformation in the rock lay that contains hydrocarbons. Fault-related features may also be considered as structural traps. Stratigraphic traps are formed when other beds seal a reservoir bed or when the permeability changes within the reservoir bed itself.

Many industry sources define natural gas extracted form tight sandstone formations (tight gas) as unconventional, mainly due to the expensive extraction technology employed, and relatively low well production rates experienced. Since tight gas barely differs from conventional natural gas in regards to geological origin, exploration technology and envrionmental impact, we will not directly address this source in this section.

Recent interest in developing “unconventional” natural gas resources is mainly driven by the increasing cost of conventional natural gas, as known deposits are depleted and the majority of new finds are more difficult to develop and extract. Political decisions to regain more national control over energy resources are a further driver for the currently very strong interest in unconventional gas development, particularly in the United States and Japan.

Currently there is no commercial production of unconventional gas in New Zealand, although exploration and fracturing has commenced. It is likely that CBM, shale gas and tight gas extraction will develop when the New Zealand domestic natural gas market tightens with resulting increase in floor price. These resources will provide an in-fill / buffer function within the natural gas supply, but volume of supply is highly uncertain. The relative rate of development will be influenced by production cost and risk as well as environmental performance. The development of these technologies in New Zealand is disadvantaged by the potential for further large conventional natural gas developments and uncertainty over whether or not there is significant resource potential.

The exploitation of methane hydrates as a potential energy source is an immature technology with potential to vastly increase energy availability. Recent trials suggest that extraction of this resource is technically feasible in some geological environments (i.e. polar), subject to further research and investment. A study of the potential for methane hydrate development in New Zealand (CAENZ, 2009) suggested that there would be need for a significant advance in extraction technology and the development would have to be sufficiently large to justify the development of associated gas demand e.g. LNG export terminal. The East Coast margin is considered one of the single largest gas hydrate provinces in the world, and may be favourably positioned for extraction, as it is close to land and supporting infrastructure. If technological advancements allow utilisation in a safe and environmentally acceptable manner, then methane hydrate developments could make a significant contribution to New Zealand’s energy needs.

4.5.1.1 Scale

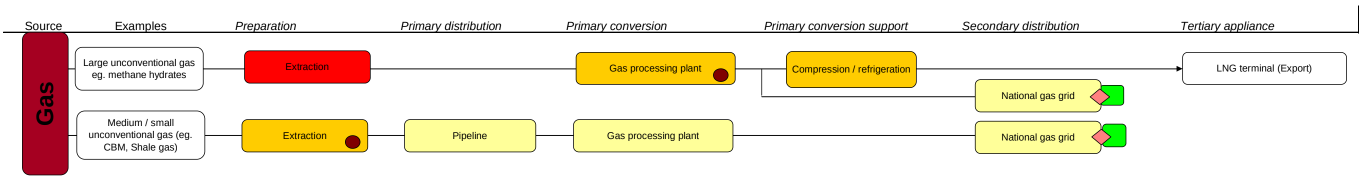
CBM, shale gas and tight gas extraction technology is similar to conventional natural gas extraction technology. Because of the relatively lower extraction rates, these developments tend to be small / medium scale developments.

Methane hydrates developments have high technical risk and would require significantly more compression than conventional gas developments, all of which is expensive. Development of hydrate deposits below the sea floor in the deep ocean would require many wells compared to the number required to exploit a conventional gas field and it may be that if technologically feasible, hydrate extraction is only feasible economically if developed on a very large scale.

4.5.1.2 Pathways

The energy pathways associated with unconventional gas resources are essentially identical to those of natural gas i.e. extraction, gas processing, transportation and common utilisation. As indicated above, the most significant difference (with respect to conventional gas), is that extraction is considerably more difficult. After gas processing, the product (i.e. natural gas) is essentially identical to natural gas sourced from conventional reservoirs, hence gas utilisation follows the same common pathways that are addressed in Section 4.4.1.4.3.

Figure 4.5.2 – Unconventional gas energy pathways



A full view of the pathway is presented in the Pathway Overview Map at the start of this document.

4.5.1.3 Quality of the resource

A common characteristic of unconventional gas resources is that they are predominantly methane and carbon dioxide i.e. they contain very little heavier hydrocarbons such as propane or butane, and no natural gas condensate. The quantity of carbon dioxide ranges from minor (<1%) to significant (>80%) – CBM usually has a few percent carbon dioxide. Methane hydrates can contain other light gases such as nitrogen, carbon dioxide and ethane. In practice however, most hydrates contain >90% methane.

Most unconventional gas is called 'sweet gas' due to limited quantities of contaminants, in particular hydrogen sulfide. For each 1m³ of gas hydrate, approximately 164m³ of gas and 0.9m³ of water will be released. The water must be removed by dewpointing and dehydration before the gas is sufficiently dry for sale.

4.5.1.4 Myth busting

During the relatively short period of time that unconventional gas resources have been considered as a meaningful substitute and addition to conventional natural gas resources, many great hopes about the cost and scale of these new opportunities have been raised. Consequently myths have been created where initial projections could not be backed-up by demonstration. Although unconventional gas from CBM and shale beds have lived up to expectations better than unconventional oil, there are still a number of serious misconceptions about the resources in circulation.

The most important myths pertain to the scale of the resource, extraction rates, and costs. Estimations about the size of unconventional gas resource potential vary hugely - in particular estimates of the world's methane hydrate endowment. Early estimates (Laherre, 2009) projected that methane hydrates are the most abundant form of organic carbon on earth. Over recent years these estimates have been dramatically lowered, nevertheless, the most recent and conservative studies still define the world's unconventional gas endowment at many times the size of known conventional gas deposits. Given the size of the resource, many people have concluded that this resource base can negate concerns about "peak gas" and provide abundant and cheap gas supplies far into the future. Analogous to "peak oil", such projections have generally disregarded the limiting nature of extraction rates and immature technology – even though there may be massive resources, it may not be possible to extract these resources at a rate and price which sustains current demand growth.

In recent times the aggressive development of unconventional gas resources in some regions (i.e. coal bed methane in Australia and shale gas in the United States) has led to a decline in gas prices. Some economists therefore assume that development of unconventional gas resources will lead to lower gas prices well into the future. After the 'sweet spots' have been developed, the less attractive resources will have to be developed using production technology that is more advanced and expensive than conventional technology. Since many of the technologies that would support unconventional gas developments are still in development or have not been trialled, it is difficult to evaluate with certainty, the risks and costs associated future unconventional gas developments. Much progress still needs to be made before we can confidently distinguish between legitimate concerns and myth based fear mongering.

4.5.2 Introduction to resources

Coal bed methane is an unconventional gas extracted from buried coal seams. It is associated with most coal deposits. The gas is generally of high quality, with very low concentrations of sulphur, CO_2 and other contaminants. The gas can often be injected into a gas network without extensive processing. Globally, major coal regions are also major regions for CBM development. Commercial development has largely centred on deposits in North America and Australia.

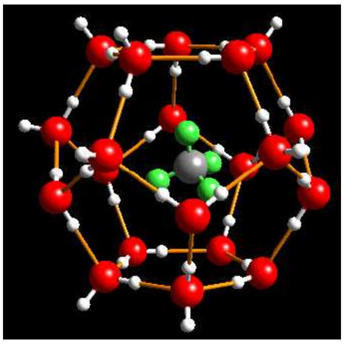
New Zealand has coal deposits throughout the North and South Island and consequently a good resource base for CBM developments. However, the greater part of New Zealand's coal reserve is either lignite or sub-bituminous coal and bituminous coal.; these low rank coals have significantly less potential for CBM than do the higher rank bituminous and sub-bituminous coals common in Australia (e.g. Queensland) and present locally in Southland and West Coast. Between 5 and 8 companies are currently exploring for CBM opportunities in New Zealand, but progress has been slow to date, with no commercial projects in production so far. Early exploration of CBM potential from coal deposits in the Waikato were found to have relatively poor yield by world standards i.e. the levels of well stimulation (fracturing) required made field development uneconomic. Exploration in the South Island identified several deposits which appeared to be relatively easy / cheap to produce, but the lack of gas pipeline infrastructure restricts development scale to local industrial and / or electricity generation options.

Shale rocks are very widely distributed throughout the world, however current exploration and production focuses only on high quality, gas rich formations. While options for shale gas production are investigated in many countries throughout the world, most of the commercial production is conducted in the United States, where shale gas currently supplies ~20% of national gas needs. New Zealand has shale rock deposits throughout the North and South Island which could potentially yield shale gas.

Methane hydrates are methane gas held in clathrate form under high pressures and / or low temperatures in Arctic permafrost or below the seabed. Methane hydrates are a unique chemical substance in which molecules of water form a lattice that encloses, molecules of methane (and related gases). Research during the past two decades has revealed that gas hydrates exist as a void-filling material within shallow sediments (on-shore in the Arctic and within deep-water continental margins) and as massive "mounds" (often in association with unique chemosynthetic biota) on the deep sea floor. The gas hydrates will sublime into gas if pressure is reduced or heat applied. The capacity to change form from solid to gas represents both hazard and opportunity. Historically, methane hydrates formations were considered areas to

Figure 4.5.3 - Model of methane hydrate structure

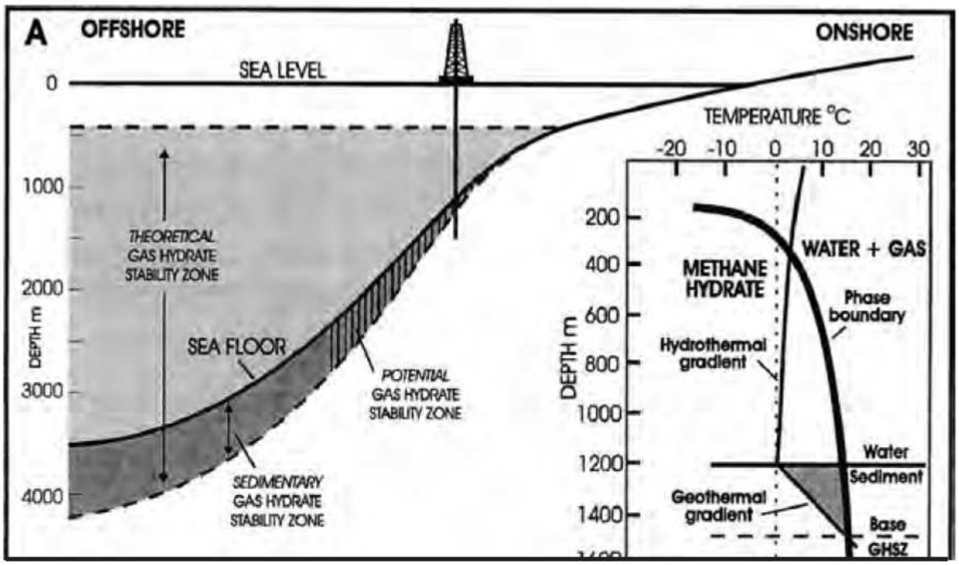
Methane (green/gray molecules) enclosed in water lattice (red / white molecules)



avoid because sediment disruption and drilling could trigger massive gas and pressures releases posing a hazard to personnel and tools. If methane hydrates can be captured, then some of the planet's largest stores of organic carbon would be available in the form of natural gas.

Methane only exists in hydrate form under specific temperature and pressure conditions, known as the 'gas hydrate stability zone'. The temperature and pressure conditions for hydrate formation for offshore settings is illustrated in Figure 4.5.4. Gas hydrates are effectively a store of hydrocarbon gas that has seeped up from sediments and rocks which are more deeply buried.

Figure 4.5.4 - Methane hydrate stability zone in oceanic setting



Source: CAENZ, 2009

New Zealand has one of the single largest known gas hydrate provinces in the world. Gas hydrates occur along the East Coast and Fiordland margins in water depths greater than about 800 metres. Most research has been undertaken on the East Coast province, with over 100 days of surveying being undertaken in 2006 / 07. The extent of gas hydrates off-shore of Fiordland is less well known and resource potential is more speculative, as summarised in Table 4.5.5.

Table 4.5.5 – The Hikurangi and Fiordland methane hydrate provinces

	Hikurangi margin	Fiordland *(Note 1)*
Area of gas hydrate	50,000 km^2 *(Note 2)*	2,200 km^2
Volume of gas hydrate	228.5 km^3 *(Note 3)*	10 km^3
Volume of gas at STP	34,474 km^3 *(Note 3)*	1,600 km^3 *(Note 4)*
Theoretical volume of recoverable gas at STP	23,010 km^3 *(Note 3)*	1,100 km^3

Notes:
1. Adapted from Gorman, Fohrman & Pecher (2006)
2. Adapted from Henrys, Pecher & Charm NZ Working Group
3. From Henrys et al (2008) and Pecher & Henrys (2003)
4. From Henrys et al (2008)

For the East Coast margin, the area of widespread gas hydrate indication, based on bottom simulating reflectors (BSRs) observed on seismic data, is about 50,000 km² with an estimated volume of gas hydrate of at least 228.5 km³. Of this volume, less than 10% present where high gas hydrate concentrations are associated with strong bottom simulating reflections (BSRs) linked to broad geological structures that could enhance fluid flow. Pecher and Henrys (2003) estimate that there are about 813 trillion ft³ (TCF) of technically recoverable (with no regard to cost) reserves on the East Coast margin, although only a small portion of this may be in satisfactory concentrations to be economically viable for production. If 5% of the resource were economically viable then over 40 TCF (42,700 PJ) of gas would be producible, i.e. about 12 times larger than the initial in-place reserves of the conventional Maui gas field. These estimates are based on an incomplete data set and do not include conventional gas reserves trapped by the gas hydrate zone, or the yet-to-be-assessed Fiordland margin hydrates. Much of the reserves are found in muddy sediment as illustrated in Figure 4.5.6.

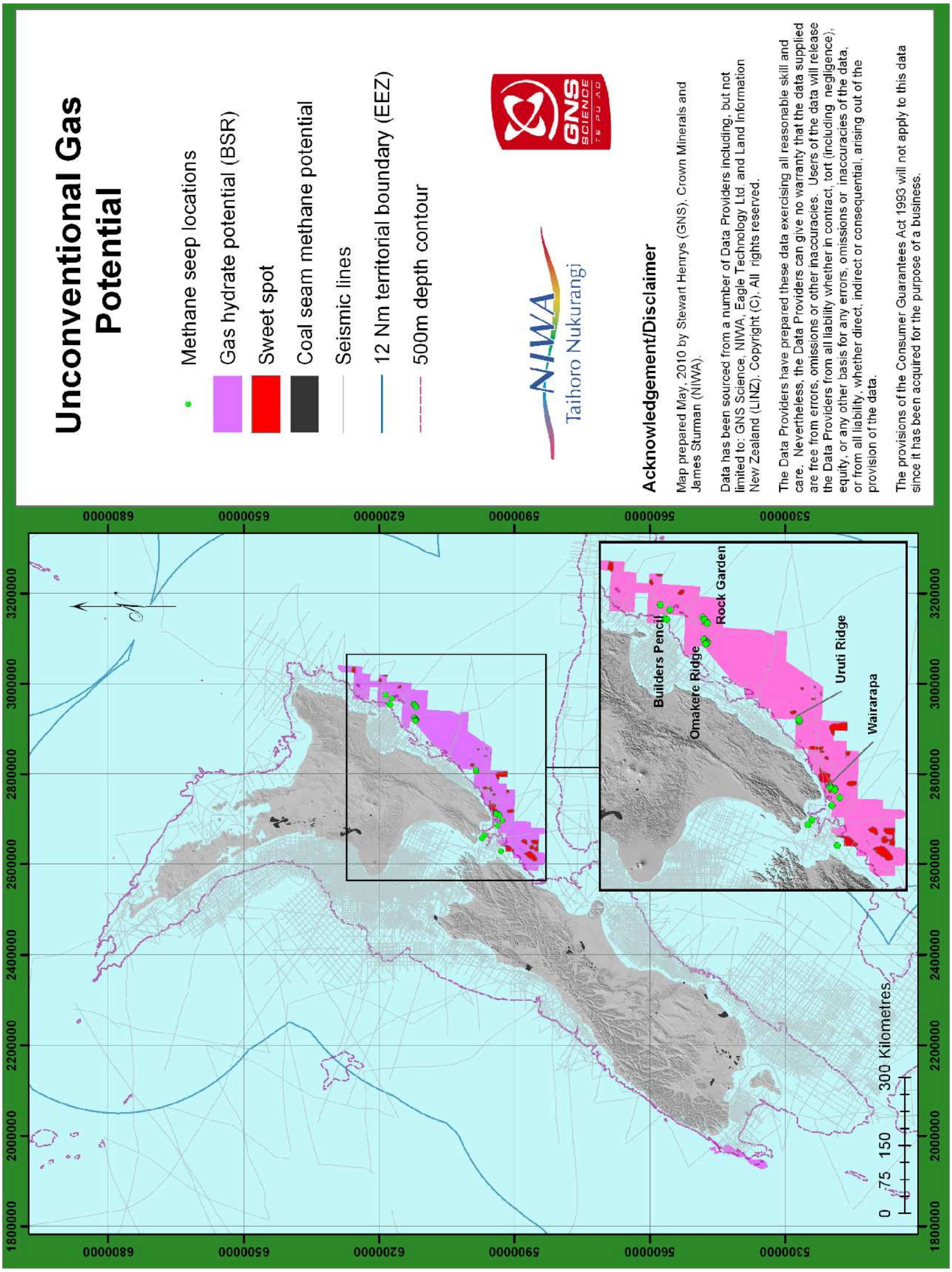
Figure 4.5.6 - Methane hydrates recovered from the East Coast in 2007

Gas hydrates occurring as thin (< 1 cm) veins

Source: Renard Centre of Marine Geology.

The locations of potential unconventional gas reserves are summarised in Figure 4.5.7.

Figure 4.5.7 – Potential unconventional gas resources



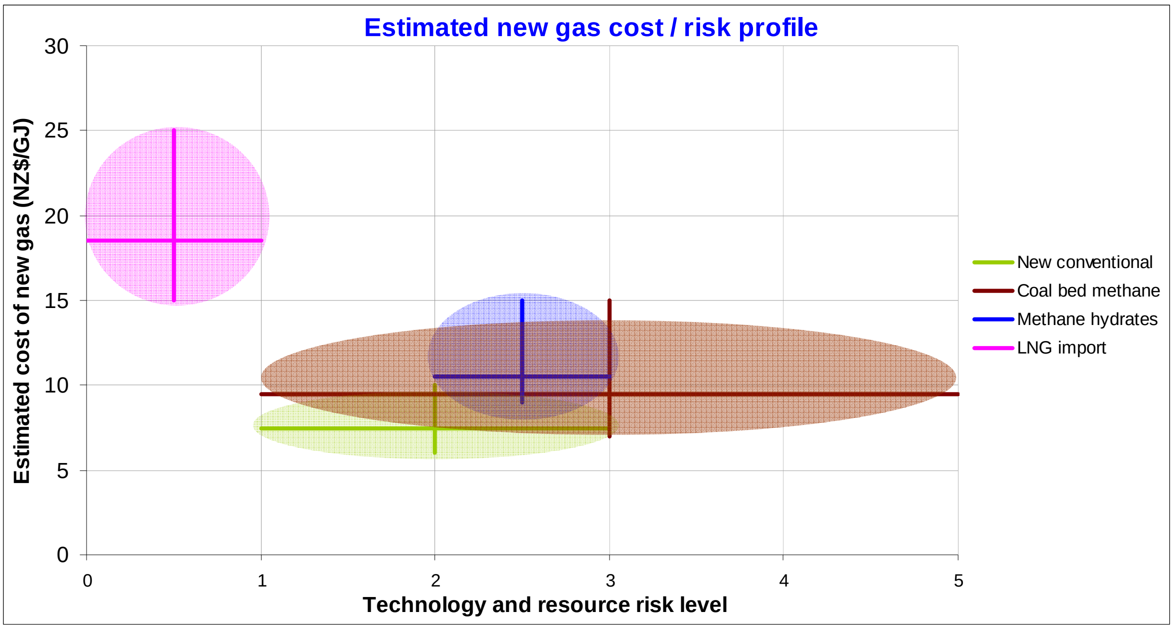
4.5.2.1 Resource uncertainty

Large uncertainties exist in the size of the resource and in the estimates of producible volumes. There is also uncertainty surrounding the technology that will be adopted for production of unconventional gas.

4.5.3 Barriers and limitations

For most unconventional gas resources, there are substantial barriers to development. For CBM and shale gas developments, the most significant obstacle appears to be cost, although environmental considerations also play a role, and there is still uncertainty about the size of the resource. For methane hydrates, the proposed production technology has yet to be demonstrated at a commercial scale. Since the costs of methane hydrate extraction are likely to be greater than conventional gas of equivalent size, the cost efficiency associated with large scale developments will be required in order to be competitive with smaller scale conventional gas production. The range of technical risk and cost risk was summarised by Heubeck (2009) as illustrated in Figure 4.5.8.

Figure 4.5.8 – Technology and resource risk profile and estimated marginal cost for a range of potential natural gas supplies



Coal bed methane covers a wide range of risk profiles and production costs. The ease of identifying CBM regions and the relatively simple and mature production technology, is counter-balanced by low well and field productivity and short production life. Around the world indications are that the porosity of the reservoir (determining flow rates and the need for fracturing) and disposal options for the co-produced water from CBM fields are the paramount factors determining the success of CBM ventures. Coal bed methane in New Zealand is still in the very early stages of development, and may well be subject to surprising developments. Preliminary data seems to indicate that CBM production effort can vary dramatically from field to field, and even within different pockets of the same field. Early indications are that most of the CBM resources in areas that could easily be connected to the gas pipeline network are rather difficult to produce and hence expensive. Conversely some of the fields that are easier to produce (e.g. West Coast prospects) cannot be easily delivered to market. Compared to other unconventional gas options in New Zealand, CBM has the lowest resource and technology risk. The fact that CBM can be developed gradually in small increments is seen as an additional benefit.

The major barriers to the development of shale gas, if a resource were proven, appears to be cost. While shale gas can be extracted from a wide range of shale formations, the high production cost, in particular the need for intensive fracturing, currently limits the scope to the easiest and most prolific prospects. Industry experts estimate that even the easiest US shale gas developments require a gas price of around $10/GJ (US$7/MMBTU) to be economical (Dave Cohen, 2009) which is about twice the current New Zealand natural gas price. New Zealand shale prospects to date have not been intensively evaluated, so the effort and cost of potential New Zealand shale gas developments remain very much unknown. As New Zealand hosts only a relatively small oil and gas workforce and equipment base, with no particular expertise in horizontal drilling and fracturing methods necessary for shale gas developments, know-how and equipment for potential shale gas developments will have to be imported, which, given New Zealand's remoteness, will further increase the cost of shale gas ventures here. Environmental concerns regarding ground water contamination from fracturing fluids, and the visual landscape impacts of a large number of short lived shale gas wells and associated support infrastructure are a further deterrent for potential New Zealand shale gas developments. Given New Zealand's great potential for conventional gas developments, it can be assumed that these barriers will prevent shale gas development at a meaningful scale for the next few decades.

The biggest risk for methane hydrate developments is the currently untested production technology. Despite decade long efforts and millions of research dollars spent predominantly by the United States, Japan and South Korea towards solving these issues, there are currently no commercial projects or pre-commercial pilot projects in operation. Major challenges for most deep sea methane hydrate developments around the world are working at great depth in waters far off-shore, issues of ground destabilisation around extraction sites and a lack of proven reservoir management techniques for these rather heterogeneous and unstable reservoirs. In this regard the New Zealand methane hydrate resource does have distinct advantages over other deposits throughout the world, as some of it is located close to shore, at moderate depth and could potentially even be drilled from on-shore production platforms. On the flip side, the East Coast hydrates are located in mudstone-dominated geologic environment. No methane hydrate extraction trials have been conducted in this environment, and there are serious doubts about hydrate extraction from mudstone lithologies.

Should suitable hydrate extraction technologies be developed, they will certainly be more expensive than for conventional natural gas developments, however methane hydrate developments offer the opportunity to benefit from economies of scale. Some models assume methane hydrates production facilities will have a capital cost which is roughly twice that of conventional gas developments, and the operating costs will be 1.5× greater (RPS group, 2008; CAENZ, 2009). If the technological barriers could be overcome, it is therefore plausible that unconventional gas extracted from methane hydrates could be cheaper than other forms of unconventional gas, and potentially even be competitive with smaller and / or more complex conventional gas developments.

Too little is currently known to comprehensively judge the environmental performance of unconventional gas developments. Some coal bed methane developments in Australia have been praised for providing a novel freshwater source for agriculture in arid regions, while other CBM developments in Australia and the US are seen as a threat to agriculture and the environment due to large quantities of saline water requiring disposal. Shale gas developments in the US have been criticised for using potentially toxic chemicals for rock fracturing and well stimulation, which may endanger ground water sources. Shale gas developers insist that such methods do not pose an environmental risk. A lot of speculation also surrounds the environmental dangers potentially posed by deep sea methane hydrate developments. Apart from questions around the disposal of large quantities of fresh water in sensitive marine environments and accidental release of methane from the ocean floor, several experts have raised the issue of methane hydrate developments accidentally destabilising shelf margins. The consequences of such destabilisation could be severe - ranging from triggering tsunamis to the release of vast quantities of methane from the disrupted sediments.

4.5.4 Introduction to conversion technology

Coal bed methane technology extracts methane gas from underground coal seams by means of desorption. This technology is applicable to most deeper buried coal deposits, with the particular advantage of being able to extract energy from coal seams that are too deeply buried or to inconsistent for coal mining. Deep buried coal seams (200m to 600m below ground) usually hold both water and methane gas at elevated pressures. The methane gas is generally absorbed onto the coal's matrix. Production wells are drilled into the coal seams, usually with horizontal extensions. Pumping water from the seam results in a pressure drop which releases methane from the coal matrix. Both water and raw gas are brought to the surface together. The raw gas from CBM is usually of very high quality, with little sulphur, CO_2 or N_2 contamination, and can often be injected into a gas transmission network without extensive pre-conditioning. In comparison to conventional natural gas and other unconventional alternatives:

- CBM has little resource risk in established CBM areas (which are easy to identify) i.e. few wells turn out as failures
- Lead times for developing CBM projects are usually short
- The production of CBM is labour and equipment intensive
- The environmental performance of CBM developments has so far not been comprehensively evaluated, but potential risks appear to be manageable in the New Zealand context.
- Production rates from CBM wells are much lower than conventional gas wells and well / field life time is shorter

- Production costs are significantly higher than for conventional natural gas

Due to these constraints even large CBM deposits can sustain only relatively modest flow rates and total CBM production in a particular field, area or country can only be increased slowly. It would therefore appear that CBM in New Zealand would fulfil a buffer function in response to high natural gas prices.

The source rock of shale gas generally has very poor permeability and conductivity for gas. Where this rock has natural fractures, shale gas has been produced (in the United States) using conventional technology. The extraction of shale gas from shale rock without natural fractures has only recently become practical, due to technological advances in horizontal drilling and rock fracturing technologies. Modern, shale gas developments therefore rely on horizontal extensions (up to 10,000 feet long) of wells drilled into the shale for maximum connectivity of gas reservoir and production well. Fracturing, the opening up and extension of existing fissures and creation of new ones in the rock, is accomplished by injecting pressurised fluids down the bore hole and around the well-reservoir contact zone. Only the combination of horizontal wells and fracturing can ensure sufficient reservoir to well connectivity and consequently economical well production rates. However, as the space of shale rock around each well bore affected by fracturing is limited, shale gas wells usually show very steep individual depletion rates as the fractured reservoir is drained very rapidly. Well depletion rates of 60% to 90% p.a. are common for most US shale gas developments. The quality of gas extracted from shale can vary very widely depending on the quality of the source rock, and temperature, pressure and chemical conditions during the gas formation process in the geological past. Currently only shale gas deposits of high gas quality are targeted, as the requirement for expensive gas treatment would increase the already high production costs even further. The quality of gas contained in New Zealand shale formations is currently unknown. In comparison to conventional natural gas and other unconventional alternatives:

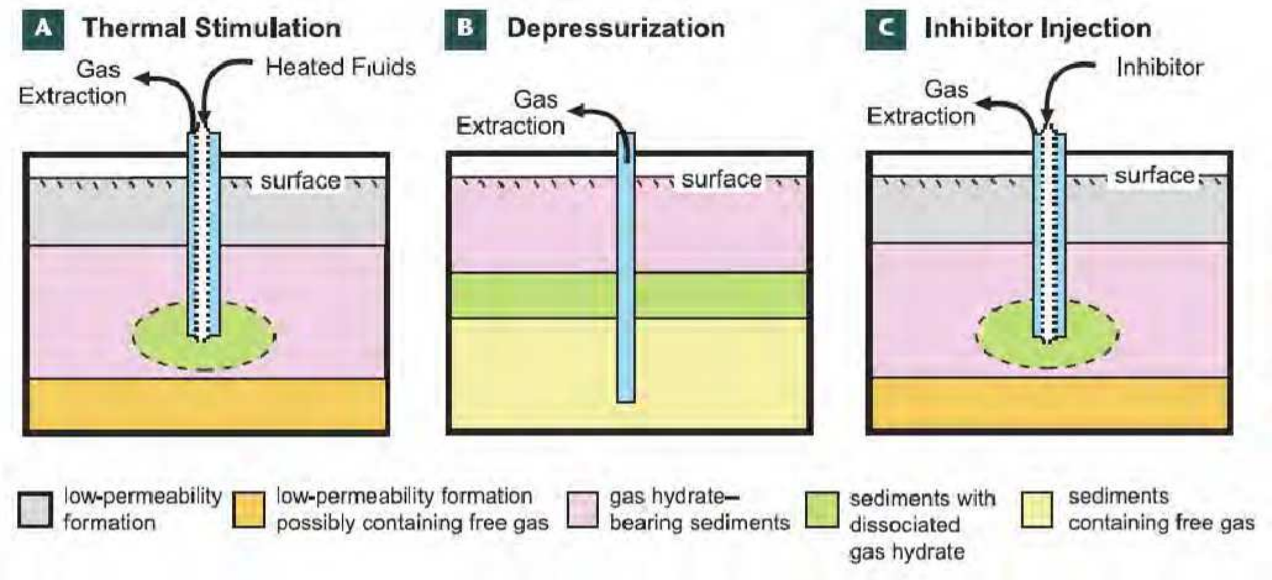
- Shale gas has relatively little resource risk in established areas, however ultra fast well depletion rates can be an issue
- The production of shale gas is labour and very equipment intensive
- Production rates from shale gas wells are much lower than for conventional gas wells and individual well production rate declines are very large
- Production costs are significantly higher than for conventional gas
- Environmental concerns, such as groundwater contamination, could be a deterrent for shale gas developments in New Zealand.

Given New Zealand's vast potential for conventional gas exploration and development, it appears unlikely that shale gas developments which are associated with many financial, management and environmental risks will become a substantial energy resource in this country any time soon. Even other unconventional gas resources such as CBM would appear to be more viable and less risky, and therefore most likely be developed sooner and at a larger scale than shale gas.

The second opportunity associated with gas hydrates, it the potential for production of the free gas from underneath hydrate caps.

Methane hydrates are only stable within a specified temperature and pressure range (see Figure 4.5.4), hence extraction techniques must destabilise the hydrate by either: (i) increasing temperature, (ii) reducing pressure, (iii) destabilising matrix with chemical i.e. hydrate inhibitors. The selection of preferred extraction technology appears to be related to the location of the hydrate formation relative to free gas and seal layers – see Figure 4.5.9. In-situ dissociation seems to have many advantages over relocation and subsequent dissociation; hence almost all extraction techniques propose using conventional gas reservoir production systems. Methane hydrates have not yet been produced commercially, but technology development is progressing swiftly.

Figure 4.5.9 – Production methods for extracting natural gas from methane hydrate deposits



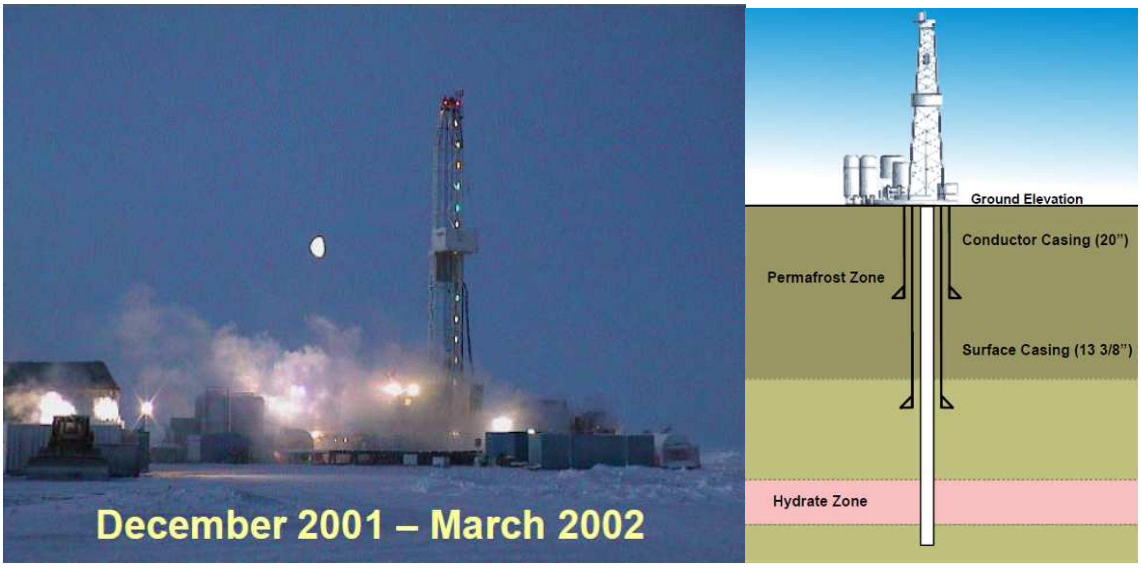
Source: Ruppel 2007

The longest methane hydrate production run ever reported – 13,000 m³ over 6 days from Mallik, Canada - utilised the depressurisation methodology. Preliminary trials using methane hydrate inhibitors e.g. methanol, LDHI, carbon dioxide have also been carried out, but not with the extended runs of Mallik. The major technological challenge is to maintain bottom hole stability within the production zone whilst accelerating methane recovery. It should be noted that New Zealand's deep sea hydrate deposits are of a type very different from the sub-permafrost hydrates at Mallik, and hence may well require different technology, and face different challenges.

Once methane has been extracted, it can be handled using conventional natural gas technologies. Initial experimental results indicate a very high quality for gas extracted from methane hydrates, which is largely deprived of contaminants such as H_2S or N_2. In comparison to conventional natural gas and other unconventional gas extraction:

- Resource risk is not understood
- The extraction technology is yet to be proven
- Lead times for developing methane hydrate projects are expected to be similar to conventional natural gas projects, i.e longer than for other unconventional developments such as CBM
- Each well will have significantly lower production rates and higher water cuts. This in turn will require a larger number of production wells and higher operating costs (Hancock, 2008).

Figure 4.5.10 –Mallik used conventional gas technologies to produce commercial quantities of gas from hydrates



Source: Pierce, 2008

It is well recognised that the production costs of methane hydrate extraction will always be higher than for a conventional natural gas field of comparable size. In spite of this, the development of methane hydrates projects could still be driven by economic imperatives such as:

i) The economies of scale which may be associated with methane hydrate production could mean that is it cost effective in New Zealand if there is no large scale conventional gas production.

ii) Imported LNG may be more expensive than gas produced from methane hydrate facilities >150 PJ/y.

iii) Natural gas from larger methane hydrate production facilities could be used to provide national energy security (as a transport fuel) or export revenue.

iv) Gas has lower GHG emissions than coal or oil per energy unit delivered.

A fuller explanation of the merits and risks of methane hydrate developments can be found in Hooper et. al. (CAENZ, 2009). Recent activities related to gas hydrate development have included:

- The US roadmap for gas hydrate development includes drilling in both the Arctic and the Gulf of Mexico before 2011, with production testing scheduled before 2015 (US DOE, 2006).
- Production of gas hydrates from within permafrost has been tested in Canada (Dallimore and Collett, 2005).
- The Japanese government, in association with the government of Canada, has run an extended production tests at Mallik over the winter seasons 2006 / 07 and 2007 / 08 (US DOE, 2007).
- The first flaring of gas produced from hydrates at the onshore, permafrost Mallik site in the Canadian Arctic was in December 2007 (Pierce, 2008).
- April 2008 – first production of commercial quantities of gas from hydrates using conventional oil and gas technologies over a 6-day production run at Mallik[19].
- Based on success at Mallik, Japan announced plans for commencement of offshore extraction technology trials in 2009-2010[20].

In summary, the production technology required to commercially extract natural gas from methane hydrates is still in development. There is a great deal of optimism being driven by resource limited nations (e.g. Japan, India, Korea, United States) to advance this technology. The timeframe for commercial production is uncertain (possibly 15 years), and will only be viable at large scale (i.e. >150 PJ/y). The requirement for large scale development would suggest that this gas will only be extracted in conjunction with industrial demand (e.g. GTL, methanol, fertiliser or LNG) and would likely link to the existing natural gas network.

[19] Dominion Post “Gas rich ice ignites a fuel frenzy” [16/4/2008; Business Section Pg 8]
[20] *Ibid*.

4.5.5 Asset characterisation

The perception that numerous small CBM developments will provide a buffer in the supply to the natural gas market has been accommodated by providing several assets in: Waikato, Taranaki and Otago. For simplicity the assets were characterised as standard gas assets, with the research time reduced by 1 year. No shale gas developments have been characterised at this point.

Methane hydrate production in not considered in either the 'continuity' or 'political' scenario, but is considered in the 'redevelopment' scenario. The phasing and costs associated with CAENZ (2009) base case installation has been employed, namely:

	10 PJ/y upgradable facility			150 PJ/y upgradable facility		
	CAPEX / OPEX pa. (NZ$ million)	Duration (years)	Risk	CAPEX / OPEX pa. (NZ$ million)	Duration (years)	Risk
Research (and assessment)	22	11	4	66	1	1
Consenting (and FEED)	44	1	2	132	2	1
Finance and construction	1300	3	3	2743	2	2
Operation	81	25	2	280	25	1
Decommission	65	1	0	202	1	0

Additional considerations include:

- Less than 5% of the production is considered to be used as a fuel within the extraction and processing of these assets. The associated GHG emissions are assessed based on this level of combustion (yielding approximately 52 kt CO_2/PJ) and with 0.5% fugitive emissions of methane.
- Water recovery is as per RPS Energy case study profile
- Areal footprint is considered minimal.

4.5.6 Research status

Prospecting, development and production of coal bed methane resources in New Zealand seems to be largely driven by industry (private and SOE). These developments can leverage from a well established information base about New Zealand's coal resources that has been built up over decades. Supporting technology, know-how and some personnel will be imported from overseas. Given New Zealand's limited, albeit substantial and potentially important, CBM resource, this appears to be a practical pathway, as there doesn't seem to be a specific need for customised Kiwi technology for the CBM resource; in fact some aspects of New Zealand CBM developments (e.g. production water disposal) are a relatively simple matter by world standards.

Table 4.5.11 – Research status – Coal bed methane

(Clear indicates 'Fair knowledge', Green highlight indicates 'Potential opportunity', Amber indicates 'Could improve', Red indicates 'Knowledge gap exists')

	International	New Zealand	Comment
Resource mapping	Evolving Australia, USA	Immature GNS, CRL, Solid Energy, L&M	General knowledge about coal basins is good, but it is less clear how this can be adapted to knowledge of CBM potential. Evaluation of seam performance in regards to gas permeability and fracturing needs to be improved.
Evaluation and feasibility	Mature Santos, Chevron	Immature Solid Energy, L&M	New Zealand would benefit for active technology following.
Production technology	Mature Santos, Chevron	Emerging Solid Energy, L&M	New Zealand would benefit for active technology following.

Based on the low probability of shale gas production commencing in New Zealand, the only recommended research directions pertain to keeping options open i.e. watching international developments, and identifying and evaluating New Zealand's resource base.

Table 4.5.12 – Research status – Shale gas

(Clear indicates 'Fair knowledge', Green highlight indicates 'Potential opportunity', Amber indicates 'Could improve', Red indicates 'Knowledge gap exists')

	International	New Zealand	Comment
Resource mapping	Evolving	Insufficient to date	Investigate faulting and fracture characteristics in shales, especially in the East Coast, and relationship between source, migration and trapping of gas in fractured shales.
Evaluation and feasibility	Evolving USA	Immature Solid Energy, L&M	New Zealand would benefit from active technology following.
Production technology	Relatively mature USA	Emerging Solid Energy, L&M	US technology and environmental performance is unclear.

Spending on New Zealand methane hydrate research is currently ca. $500k per year (FRST funded). Currently the focus is on analysing the results of recent 2006 / 07 East Coast surveys and on establishing a New Zealand roadmap for developing the resource to possible production in 10 to 15 years time. New Zealand's methane hydrate resource is considered to be world class and could potentially provide a large proportion of New Zealand energy needs as well as yielding substantial export value.

Table 4.5.13 – Research status – Methane hydrates

(Clear indicates 'Fair knowledge', Green highlight indicates 'Potential opportunity', Amber indicates 'Could improve', Red indicates 'Knowledge gap exists')

	International	New Zealand	Comment
Resource mapping	Evolving Most coastal state marine survey organisations	Immature GNS	3D seismic is required as precursor to test drilling. Better alignment of New Zealand interests / research requirements with international research programmes operating in New Zealand waters – e.g. Sonne cruise 2010. Consideration for 'encouraging' hydrates mapping as part of bids for New Zealand exploration permits.
Evaluation and feasibility	Immature Japan, Russia, USA, Canada, India	Immature GNS, CAENZ	Development of gas hydrate roadmap. Feasibility study into potential hydrates technology demo sites. Securing a New Zealand entry into the Gulf of Mexico Joint Industry Programme (JIP) as a precursor to the development of a New Zealand JIP.
Production technology	Evolving Japan, USA, India USSR	None	New Zealand would benefit for active technology following.
Extraction technology	Immature RPS Energy, US DoE	None	New Zealand would benefit for active technology following.

4.5.7 Summary

New Zealand has historically had substantial gas supply relative to demand and hence a relatively low gas price and limited exploration. The development of unconventional gas resources in this environment is risky, since there is high probability of the discovery of conventional gas fields which will be more financially attractive than the unconventional gas developments. Both CBM and shale gas developments in New Zealand are disadvantaged by their relatively small scale, high production costs, and New Zealand's significant potential for further large scale and world class conventional natural gas developments. Without government intervention, unconventional gas developments will stay at the periphery of the New Zealand gas sector.

New Zealand currently has no commercial scale production of unconventional gas. Exploration for CBM has commenced, but it is indicated that production will only commence if New Zealand domestic gas prices increase substantially. There have been a few minor explorations of shale gas potential, but no production

New Zealand has very large methane hydrate deposits located on the East Coast margin of the North Island. This accumulation is considered to be one of the single largest gas hydrate provinces in the world. The exploitation of methane hydrates as an energy resource is immature but has significant potential. Recent trials suggest that extraction of this resource is technically feasible, subject to further research and development. If technological advancements would allow utilisation of methane hydrate as an energy resource in a safe and environmentally acceptable manner, methane hydrate developments could be a game changer, not only for New Zealand's energy supply, but for the economy as a whole.

Section 4.6
Coal resources

4.6 COAL RESOURCES

4.6.1 General introduction

New Zealand's coal resource can be characterised by:

- 15 billion tonnes of in-ground resources
- Wide variation of coal properties and geological settings
- Production of about 5 million tonnes per year, equivalent to 86 PJ of energy
- Most bituminous coal production is exported
- 5% of in-ground resources are bituminous
- 20% of in-ground resources are sub-bituminous
- 75% of in-ground resources are lignite

Coal is New Zealand's most abundant fossil fuel; it was the country's main energy source in the late nineteenth century and remains an important contributor to energy supply and a significant export commodity. The main coal producing areas are the Waikato region in the North Island and the West Coast region in the South Island. Annual production is about 5 million tonnes (Mt). Recent increases have been driven mainly by export opportunities for high-quality coking and thermal coals, and increased use of coal for domestic thermal power generation. Electricity generation and iron / steel processing accounts for over half of New Zealand coal usage, with other industrial uses accounting for a third (e.g. timber, pulp and paper, cement, and meat, dairy and wool processing). The remainder is used in the commercial and residential sectors. Residential consumption is now small and in decline. Almost half of New Zealand's coal production is exported, mainly to India and Japan.

New Zealand has in-ground coal resources of over 15 billion tonnes, most of which is lignite in the South Island but includes high quality thermal coals and some extremely high quality coking coals. The world-scale South Island lignite deposits account for 75% of New Zealand's coal resources. The main deposits are well known, with technically recoverable quantities in the 10 largest deposits established at over 6 billion tonnes, equivalent to 72,000 PJ of energy, or the energy content of 20 Maui gas fields. On a per capita basis, New Zealand is very well endowed with coal resources – second only to Australia.

Solid Energy produces over 80% of New Zealand's coal, with the remainder being produced by a number of smaller, private coal producers. Almost all production is bituminous or sub-bituminous coals, in approximately equal quantities. Over 60% of production is from two large open-cast mines operated by Solid Energy at Rotowaro in the Waikato (sub-bituminous) and at Stockton on the West Coast (bituminous).

The extent of New Zealand's coal resource is well known, mainly due to the comprehensive Coal Resources Survey that was carried out by the Government, between 1976 and 1989, in response to a series of oil price rises and increasing electricity demand. This was the largest mineral exploration programme ever carried out in New Zealand and included large-scale drilling programmes, geological and resource assessments and mining feasibility studies. Outcomes from the survey included discovery of very large lignite resources in Otago and Southland.

The extraction and utilisation of coal has increasingly become controversial. Coal mining represents both an economic opportunity and an environmental hazard. From an economic perspective, New Zealand's coal reserves support a significant export industry, supply energy to the electricity, industrial and primary production sectors and have the potential to hedge New Zealand's economy and security of energy supply against oil market volatility. From an environmental perspective, the extraction of coal has significant adverse affects on the local environment as well as contributing significant green-house gas emissions (GHGs) during mining and at the point of combustion.

Gasification and carbon storage and sequestration (CCS) are technologies that could be used to reduce some of the GHG emissions associated with coal utilisation, but the application of these technologies also reduces the economic advantage of using coal.

4.6.1.1 Pathways

The quality of coal is generally defined by its carbon fraction and this also defines the likely utilisation pathway. However, sulphur and ash content, trace element contents, reactivity and many other properties affect utilisation potential. The grades of coal extracted in New Zealand and current uses are:

- Bituminous coal has the highest carbon content and low moisture content. Production is entirely from the West Coast and is mainly exported as thermal, semi-soft or hard coking coal. It is also supplied to various domestic markets, especially in the top part of the South Island..
- Sub-bituminous coal is used for electricity generation at Huntly, steel making and processing at Glenbrook and industrial use throughout New Zealand.
- Lignite has moderate carbon and high moisture contents. It is generally uneconomic to transport lignite any distance, and use in New Zealand is limited to the southern South Island.
- Peat is a coal precursor and is used in small, low-heat applications (e.g. space heating).

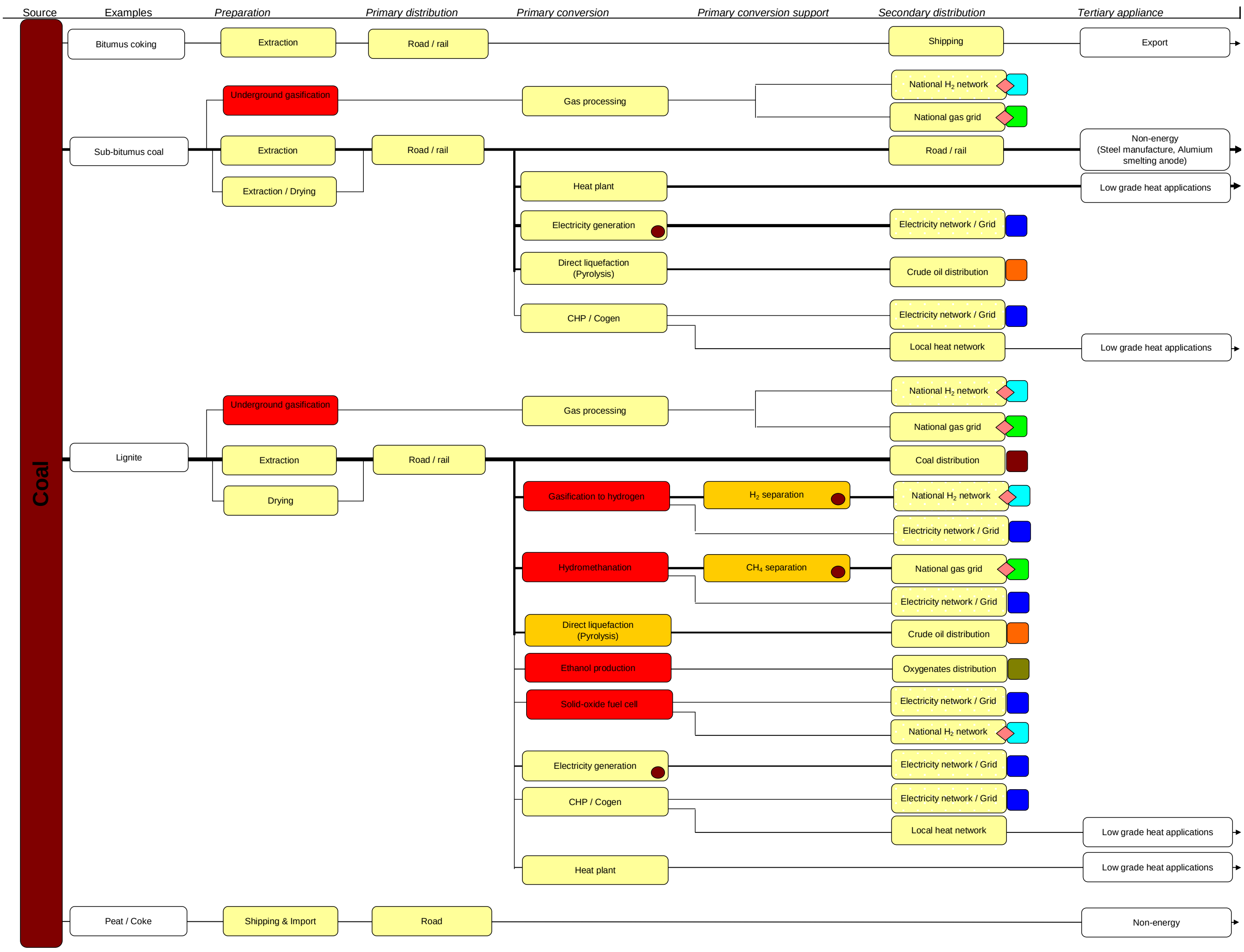
All coal is extracted either by open-cast or underground mining. Recovery rates for opencast mining can exceed 90% of mineable reserves. High recovery rates are very difficult to achieve in underground mining, and range from 75 to 10% in New Zealand mines.. Preliminary processing (e.g. crushing and drying) can be undertaken at the mine in order to meet market specifications

For small mining operations, coal is often transported by road to coal users. For larger-scale operations, rail and purpose-built conveyors are more cost-effective. One transport mechanism that has not been used in New Zealand, to date, is local gasification and transportation of primary energy as synthetic natural gas (SNG). This latter option is a more radical, but potentially feasible, mechanism for using Southland lignites.

Coal is generally used to provide high grade heat for industrial applications. Most often, the end-use is the production of steam. Steam generated at 10 barg is often used for evaporators, driers, hot water services (in schools, university and hospitals), hot water calorifiers (steam / water heat exchangers used to produce hot water), processes, autoclaves, and space heaters. High pressure steam, at 166 barg (as used at Huntly power station), is often used to generate electricity by letting pressure down across a steam-turbine generating set.

The low-pressure, low-grade-heat, steam that exits the turbine unit of an electricity-generating station may have further energy extracted from it for use in down-stream industrial and commercial applications (e.g. timber drying, district heating etc.). Significant energy efficiency advantages are gained through this combined use of primary energy for both heating and electrical power generation purposes. This method of energy utilisation is referred to as Combined Heat and Power (CHP) or cogeneration.

Figure 4.6.1 – Coal pathways



A full view of the pathway is presented in the Pathway Overview Map at the start of this document.

Coal can be converted from a solid fuel stock into a fuel stock that is better suited for use in transport applications. There are four primary mechanisms by which coal resources can be converted:

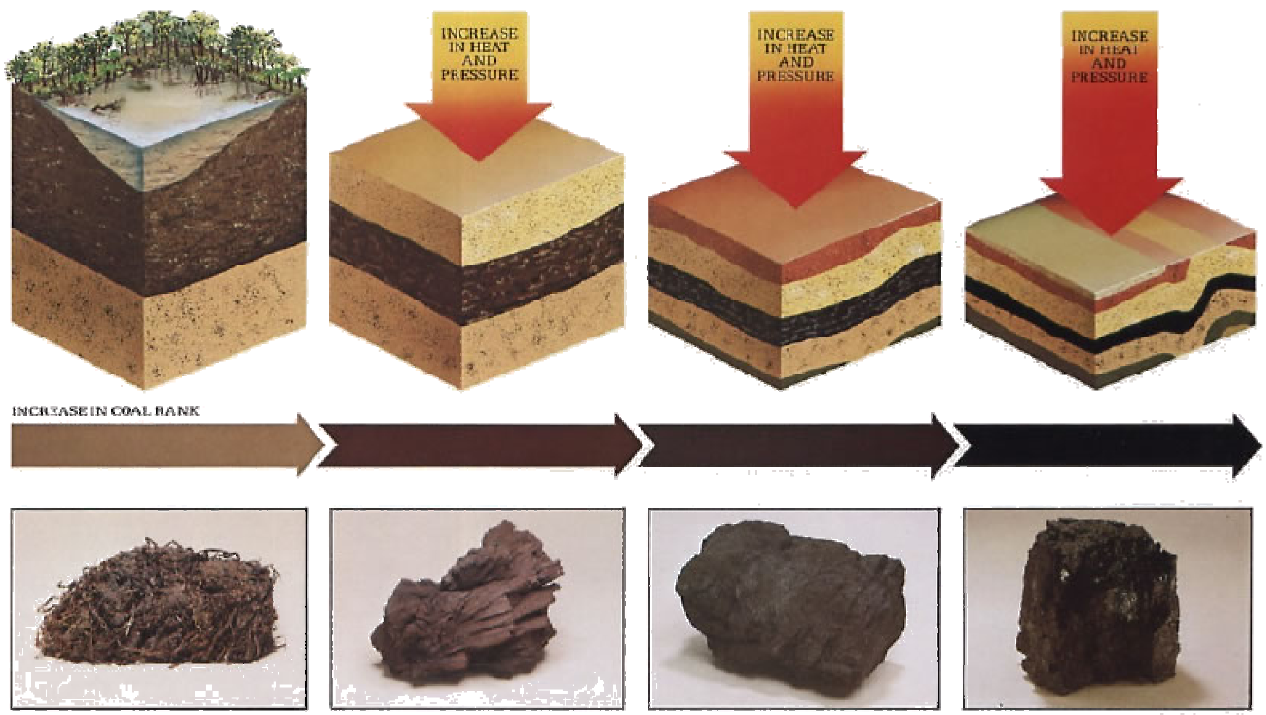
- Indirect liquefaction, also known as coal-to-liquids plant (CTL) - based on coal-gasification and synthesis of the resulting gases into liquid fuels. A synthesis plant would be located near to the lignite coal resource in Southland or Otago, with the synthetic fuels being transported by pipeline or road tankers to fuel distribution hubs.
- Direct liquefaction, also known as coal-to-crude plant (CTC) - based on coal-pyrolysis. This produces a low-grade of liquid fuel feedstock, which could also be processed at plants located in Southland or Otago and transported by road tanker. The crude feedstock would be taken to the Marsden petroleum refinery to supplement the processing of conventional crude oil feedstocks into higher-grade transport fuels.
- Underground coal gasification, which produces a low-grade syngas that can be used directly in a power station or converted to a synthetic version of "natural gas" or other products.
- Hydromethanation could produce a synthetic version of "natural gas" for distribution by pipeline. This gas could then be used directly in compressed natural gas (CNG) vehicles or converted to liquids in centralised gasification plants based along distribution pipelines in the North and South islands.

As an alternative to the use of coal-derived liquid fuels to support the transport sector, coal-fired power stations could support the electrification of the national transport fleet. Conversion of coal energy to electricity (with carbon capture and sequestration) in Southland or Otago could be used to support a national electric vehicle infrastructure, with electricity being more widely distributed to the end-users by an upgraded national electricity grid network. This alternative option has the potential to deliver "clean" vehicle technology to New Zealand – with zero emissions at the vehicle tail-pipe and centralised sequestration of carbon dioxide possible at the power station.

4.6.1.2 Quality of resource

Coal quality / rank is generally defined by moisture content and energy yield. The more valuable coals have higher carbon content and less moisture, as a result of greater exposure to heat and pressure.

Figure 4.6.2 – Illustration of coal rank



PEAT
Carbon content 60%
Volatile matter > 53%
Ave. calorific value 16800 kJ/kg
Moisture content > 75% (in-situ)

BROWN COAL
Carbon content 60 - 71%
Volatile matter 53 - 49%
Ave. calorific value 23000 kJ/kg
Moisture content 35% (in-situ)

SUB-BITUMINOUS COAL
Carbon content 71 - 77%
Volatile matter 49 - 52%
Ave. calorific value 29300 kJ/kg
Moisture content 25-10% (in-situ)

BITUMINOUS COAL
Carbon content 77 - 83%
Volatile matter 29 - 29%
Ave. calorific value 36250 kJ/kg
Moisture content 8% (in-situ)

Source: http://www.uow.edu.au/eng/pillar/images/about/coal_rank.jpg

Table 4.6.3 - Energy densities (Gross / LHV) of New Zealand coal resources

	MJ/kg	kg/ m³
Bituminous (export)	30.65	800 – 929
Bituminous (domestic)	29.51	800 – 929
Sub-bituminous	21.98	673 – 913
Lignite	14.99	641 -865

Source: June 2009 Energy Data File

4.6.1.3 Myth busting

A common myth is that coal is the cheapest energy source available in New Zealand. It is certainly true that large-scale extraction facilities can extract coal from the earth at a very competitive price. The extracted product is, however, difficult to transport and has limited application until transformed either into electricity or fuels. After the losses in energy, associated with conversion, and the costs associated with transport and conversion are taken into account, the overall cost of coal-derived energy is often comparable to, or more expensive than, energy derived from other sources e.g. geothermal, hydro or natural gas.

Much of New Zealand's large coal resource is not easily mineable.

1. Waikato sub-bituminous coals are difficult to mine because much of the resource is present at > 300 metres, and a large proportion is probably not mineable. Current extraction uses underground mining technologies mainly at a depth less than 300 metres. Even where the seams can be mined safely and economically, the percentage of coal recovered is likely to be low. It would be difficult for coal mined from deep underground mines in the Waikato to compete on price with thermal coal imported from overseas.
2. Export of high value West Coast bituminous coal earns export dollars but the resource is limited. Further restraints on the value of coal exported come from the cost and difficulties of getting the coal to market – the railway link and the coal handling and export facilities at Lyttleton may be at or close to capacity.
3. The largest of the Central Otago lignite deposits underlies a "greenfields" area of little developed native tussock grassland with very high landscape values and any proposal to mine it would probably meet fierce resistance.
4. Southland contains a vast amount of lignite, of which about 4 billion tonnes is present at less than 100 m of covering strata. Seam thicknesses are typically in the range 2 to 8 metres, and for the mining prospects the calculated overburden to coal rations were in the range 2.18 : 1 to 8.22 : 1. However, though capable of yielding millions of tonnes a year of relatively cheap fuel, the Southland lignite deposits do not compare favourably with the vast lignite deposits of Victoria, estimated to total 430 billion tonnes. Lignite seams in the Latrobe Valley of Victoria are up to 100 metres thick, with multiple seams often giving virtually continuous coal thickness of up to 230 metres. Seams are typically located under only 10-20 metres of overburden.

The other costs associated with the use of coal that are not often considered in financial analysis are the environmental 'side effects' and implications. Some of these externalities include:

- Release of carbon dioxide, methane and other greenhouse gases
- Generation of waste ash material containing heavy metals
- Emission of "acid rain" pre-cursor gases (SO_2) into the atmosphere (as a result of the sulphur content of coal)
- Changed ecological environments around mining operation sites
- Mining development interferences with groundwater and water table levels
- Impact of mining and thermal-power plant operations on local river water flows and subsequent impact on other land-uses

- Mining dust and fly ash nuisance
- Subsidence of land above mining tunnels, sometimes damaging infrastructure
- Rendering land unfit for other uses during and after mining operations.

Coal enthusiasts believe that coal can be a ‘clean’ fuel, i.e., can be made to have a low greenhouse gas footprint. For coal to be a ‘clean’ fuel, two developments must occur:

1. CO_2 recovery technology must be vastly improved
2. Secure, long-term CO_2 storage / sequestration locations must be identified

There are some recognised barriers to this potential reality that are discussed in Section 6 - “Secondary conversion”. Needless to say, the cost of developing this technology is not inconsiderable and New Zealand has yet to formally identify suitable CO_2 storage locations.

Figure 4.6.4 – International scale of coal mining

World’s largest trencher (located in Gemany) capable of 76,000m³/h

Source: http://padmasrinivas.blogspot.com/2007_07_01_archive.html

4.6.1.4 Scale

Small-scale mining operations can be cost-effective where resource quality is good and mining conditions favourable. In order to ensure demand, most small-scale operations must blend with larger operations.

The scale appropriate for regional gasification is not well understood yet, but it is suggested that a 5 MW scale of operation may be viable, provided the distance of the mine is not much greater than 10 km from the national gas grid.

An intermediate-scale of mining operation could sustain a 100 MW thermal-power generation facility. Even this scale of thermal generation is considered small and would not benefit from the scaling advantages afforded by a 350 – 1,000 MW power generating facility.

Pathways that convert coal into liquid transport fuels can only be built cost-effectively when demand for the end products is sizable (e.g. 90,000 barrel per day).

As the scale of mining operations increase, the acquired risk, capital cost, distribution infrastructure and environmental control mechanisms (e.g. land remediation and ash dispersal) must increase in scale accordingly.

Figure 4.6.5 – Scale of New Zealand coal mining

Source: Rotawaro, Huntly mine (http://www.ioqnz.co.nz/reports.php?report_type=2)
(insert): Port Lyttleton coal operations – Capable of stockpiling 250,000 tonnes, and loading 1,000 tonne/hour

4.6.2 Introduction to the resource

Workable coal seams are present in the Northland, Waikato and Taranaki regions of the North Island, and, in the Nelson, West Coast, Canterbury, Otago and Southland regions of the South Island (see Figure 4.6.6 and

Figure 4.6.7). New Zealand's total in-ground coal resource is estimated to be about 15 billion tonnes. Most of the resource is in the lignite deposits of Southland and Otago, where the 10 largest deposits are estimated to contain over 6 billion tonnes of economically recoverable coal, equivalent to 72,000 PJ [MED (2007)]. The North Island resource of about 2.5 billion tonnes (16%) is almost entirely sub-bituminous coal, most of which is in the Waikato region (see Figure 4.6.8).

There has not been a comprehensive assessment of New Zealand's coal resource estimates since that published by Barry et al. (1994) and an updated assessment is well over due. However, such a re-assessment is beyond the scope of this project and so the 1994 data are used here. Coal-in-ground figures for most coalfields are quite reliable, but those for the main producing coalfields of Huntly, Rotowaro, Buller, Greymouth and Ohai are less so, because they do not take into account recent production and resource proving. As noted previously, estimates of recoverable coal are generally uncertain and will change depending on market conditions and as a result of on-going exploration and feasibility studies.

Sub-bituminous and bituminous in-ground resources are approximately 3.5 billion tonnes, but recoverable quantities of these coals are uncertain, partly because the most recent published inventory of New Zealand's coal resources (Barry and others 1994[21]) was effectively an assessment of recoverable coal as of the late 1980s and needs extensive revision. Assumptions made in 1994 on technical, economic and environmentally acceptable recoverability may no longer be appropriate and other factors will also have changed, namely:

- Production since 1994
- New exploration by permit holders
- Commercial sensitivity of new estimates
- Most current public reporting of reserves is in terms of the JORC code, which is unsatisfactory for national energy inventory purposes.

Additional data on New Zealand coal resources and assets comprises details of coal production for currently operating mines and estimates of the known in-ground and recoverable resource. Coal production data were sourced from Ministry of Economic Development annual reports of coal production and mining company annual reports. Production data for the last five years was compiled for each coal region, coalfield and for each mine where the data was available or could be reasonably back-calculated or estimated. Figures for coal exports and imports are also included in the data.

[21] Barry and others 1994. Coal resources of New Zealand. Resource Information Report, Ministry of Commerce. http://www.crownminerals.govt.nz/coal/data/Coal_reports_details.asp?n=3132

Figure 4.6.6 – New Zealand coal regions and coal fields – North Island

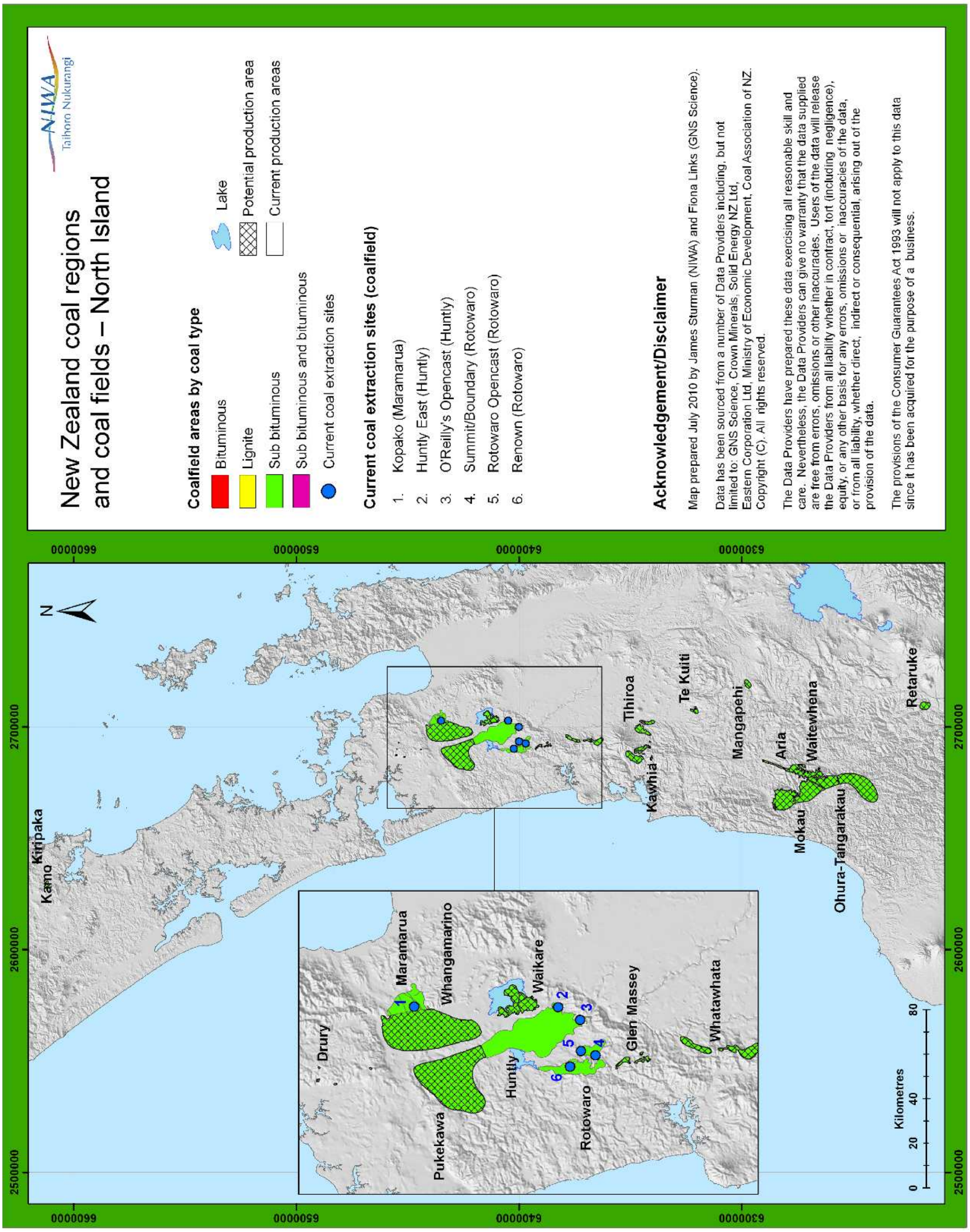


Figure 4.6.7 – New Zealand coal regions and coal fields – South Island

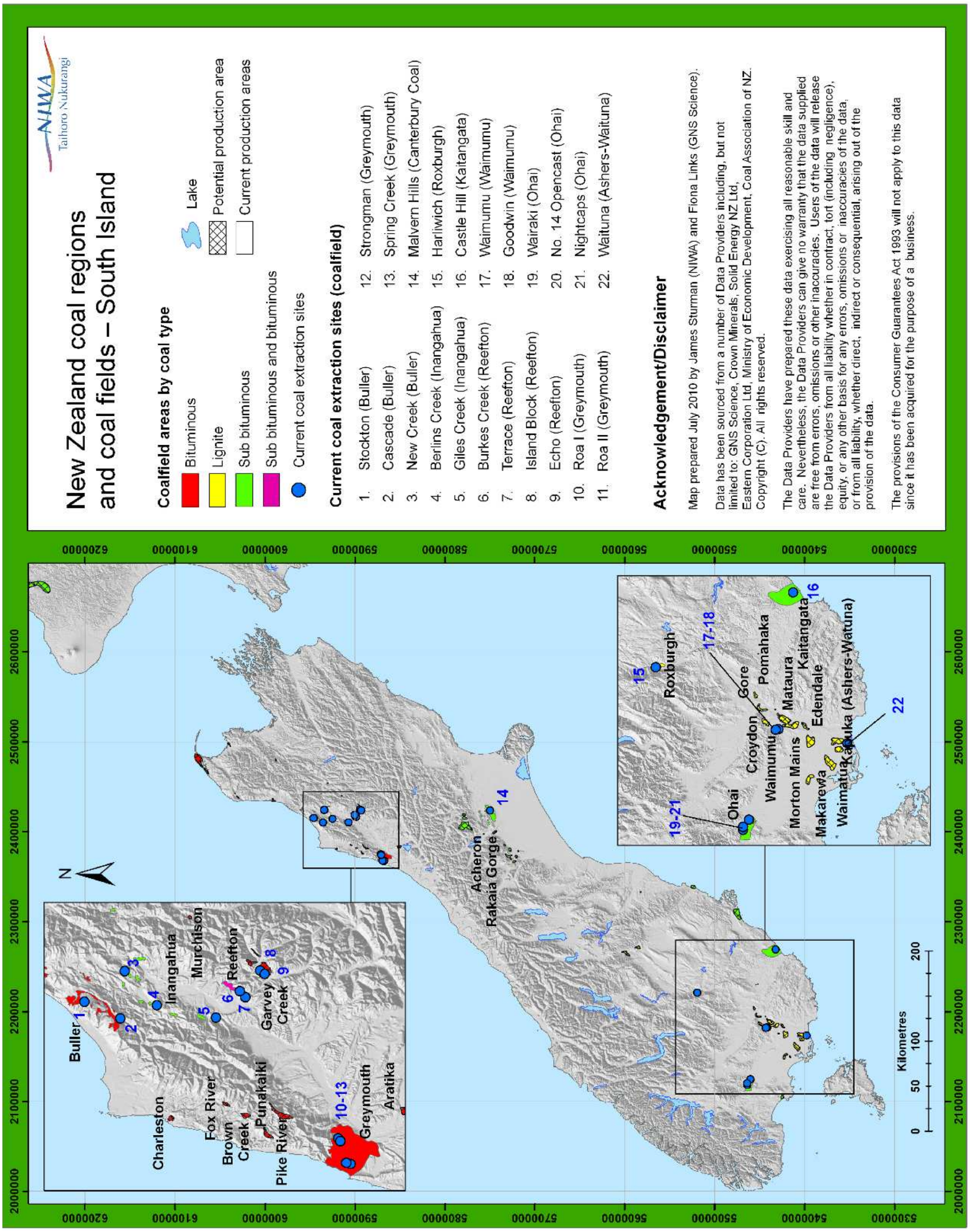
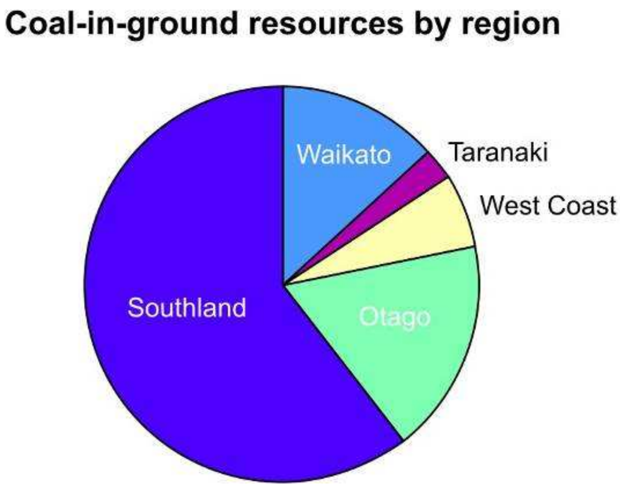
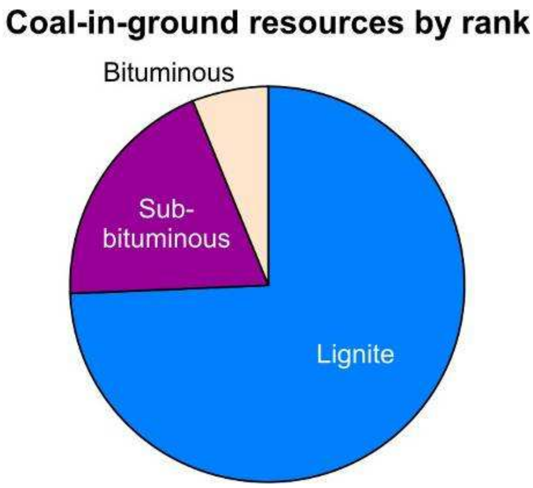


Figure 4.6.8 – Distribution of New Zealand's in-ground coal resource by region and rank





4.6.2.1 Bituminous resources

4.6.2.1.1. West Coast region

Almost all of New Zealand's bituminous coal resource lies on the West Coast. Total production from the region to date has been over 60 Mt, with most coal coming from Greymouth and Buller coalfields. Recent annual production has averaged about 2.6 Mt, representing about half of New Zealand's annual coal production. Most West Coast coal is exported, via the port of Lyttelton, to meet an international demand for high-quality bituminous coals.

Sample of bituminous coal

Source: www.teara.govt.nz

Buller coalfield is New Zealand's largest producer of bituminous coal, with current annual production of about 2 Mt/y, the majority coming from Solid Energy's Stockton opencast mine. Buller coalfield has an estimated in-ground resource of about 190 Mt, most of which can be recovered by opencast mining. Greymouth coalfield has produced more than 35 Mt to date and current annual production averages about 0.5 Mt/y, mainly from underground mines. Greymouth coalfield has an estimated in-ground resource of 540 Mt but remaining recoverable resources are much smaller. Production from the nearby Pike River coalfield is now being exported.

Several mines in Reefton, Garvey Creek and Inangahua coalfields currently produce a total of about 0.18 Mt/y of bituminous and sub-bituminous coal annually. The remaining in-ground resource for Reefton and Garvey Creek coalfields is estimated to be 25 Mt. The Terrace underground mine at Reefton closed in 2009 but may yet reopen. Opencast coal production at nearby Garvey Creek is expanding. Inangahua coalfield has two small working mines and in-ground resource of 11.5 Mt, although the coalfield remains relatively unexplored.

4.6.2.2 Sub-bituminous resources

4.6.2.2.1. Northland region

Kamo and Hikurangi coalfields have small in-ground resources of about 1.5 Mt and 1 Mt respectively, but all other areas are considered to have been worked out. None of remaining coal at Kamo and Hikurangi is considered economically recoverable [Barry et al. (1994)].

Sample of sub-bituminous coal

Source: www.teara.govt.nz

4.6.2.2.2. Waikato region

The Waikato region is New Zealand's largest producer for domestic use, supplying the Huntly Power Station and New Zealand Steel as well as other markets. While the total coal in-ground resource for the region is estimated at 2078 Mt, the remaining recoverable quantities are much smaller. Rotowaro coalfield is nearing the end of its life, and underground mining at Huntly is becoming inceasingly difficult as deeper resources are accessed. There are substantial opencastable resources at Maramarua and Ohinewai, but the extent to which they are technically mineable and consentable projects is uncertain.. Apart from these two shallow resources, most of the remaining Waikato resource is too deep to mine. Underground gasification (UCG) is a possible energy recovery option.

4.6.2.2.3. Taranaki region

Total production from the region has been about 4 Mt (88 PJ), but no mines are currently operating. The remaining in-ground resource is estimated at 380 Mt in several thin seams. [Barry et al. (1994)]. Mokau Coalfield contains the majority of the potentially recoverable resource; Waitewhena and Ohura-Tangarakau have the rest. Aria and Retaruke coalfields have small in-ground resources which are probably uneconomic.

4.6.2.2.4. Nelson region

The region has a very small estimated in-ground resource of about 1.5 Mt, entirely within Collingwood coalfield, but is worked out [Barry et al. (1994)].

4.6.2.2.5. Canterbury coal region

Canterbury Coal Region comprises several small coal deposits scattered along the eastern foothills of the Southern Alps. The main coal areas are the Malvern Hills and Mount Somers coalfields, with smaller deposits present at Avoca-Broken River, Acheron River, Rakaia Gorge and Geraldine-Fairlie. About 2 Mt has been produced from the region, mainly from the Malvern Hills and Mount Somers coalfields. Currently, a small open-cast mine in Malvern Hills Coalfield produces about

4,000 tonnes (0.07 PJ) annually. The region's resources are poorly known but are estimated at about 3.6 Mt, of which 90% is in Malvern Hills coalfield [Barry et al. (1994)].

4.6.2.3 Lignite resources

4.6.2.3.1. Otago region

Sample of lignite

Source: www.teara.govt.nz

Otago Coal Region comprises: the Central Otago lignite deposits at Hawkdun, Home Hills and Roxburgh; the small North Otago coalfields between Ngapara and Herbert and at Waihao and Shag Point; and the Green Island, Kaitangata and Pomahaka coalfields south of Dunedin. The Kaitangata Coalfield includes a large lignite deposit. Despite its current relatively small production, ~60,000 tonnes per year (1.1 PJ/year), the Otago region has a substantial in-ground resource estimated at 2,720 Mt, most of which is lignite. The other coalfields have small resources. All the accessible coal has probably been extracted from Shag Point Coalfield.

4.6.2.3.2. Southland region

Southland coal region includes the extensive lignite deposits of eastern Southland and the sub-bituminous coals of Ohai and Orepuki coalfields in western Southland. Eastern Southland lignites have been mined on a small scale since the mid-nineteenth century, and open-cast mines currently produce a total of about 250,000 tonnes (3.8 PJ) annually. Open-cast mines in Ohai coalfield produced about 240,000 tonnes (5.8 PJ) annually until recently. Solid Energy's mine has now closed.

The Southland coal region has New Zealand's largest coal resource, mostly in the lignite deposits of eastern Southland. The region has an in-ground resource of 9,390 Mt, representing 60% of New Zealand's total resource. Ohai and Orepuki coalfields are relatively minor contributors with in-ground resources of 180 Mt and 10 Mt.

4.6.3 Resource uncertainty

New Zealand's coal resource is comparatively well known, due, largely, to the national exploration and assessment programmes undertaken during the 1976 – 1989 Coal Resources Survey. The survey was essentially a resource proving exercise and little emphasis was placed on identifying recoverable coal resources [Taylor (1999)]. Arbitrary recovery factors were used in many cases, although this does not apply to the South Island lignites, which were the subject of systematic mining feasibility studies carried out by the Liquid Fuels Trust Board in the 1980s. As a result, the quantities and geological certainty of the in-ground resource is well known, The 1994 New Zealand total in-ground resource figures of 2.7 billion tonnes classified as measured, 9.3 billion tonnes as indicated and 3.5 billion tonnes as inferred are a reasonable generalisation, although this does not take account of 15 years of production and exploration

With the possible exception of the South Island lignites, the recoverable resource is uncertain because, for many areas, the mixture of factors that determine economic recovery are not evaluated to modern best-practice standards. It is never possible for all of a mineable block of coal to be recovered. In-ground quantities must be considered in terms of technical and economic mining constraints, as well as a range of non-technical constraints, in order to determine the recoverable portion. Recoverable coal is very difficult to estimate and requires very detailed mining feasibility studies. Only part of New Zealand bituminous and sub-bituminous coal resources have been evaluated to a high level of confidence of their recoverability. Combined with the fact that most of New Zealand's easily-mined bituminous and sub-bituminous coal resources have been extracted, there is considerable uncertainty over the recoverability of the remaining quite large resources.

Converting resources into reserves is dependent upon a complex mix of factors. Crown Minerals has listed these factors as including [MED (2007)]:

- Resource size and location
- Geological conditions
- Technical constraints to mining
- Mining economics
- Access to resources
- Project consents
- Market size and certainty
- Market price
- Distribution costs and infrastructure.

4.6.4 Barriers and limitations

Coal mining is a costly and, often, a technically difficult process subject to a range of technical, economic, environmental and social barriers and limitations. Barriers and limitations to the increased use of this resource include:

- Market uncertainty
- Price uncertainty, including the price currently set by coal imports
- The difficulty of bringing new mines on-stream to meet rapid changes in demand
- Increasing environmental concerns about the use of coal.

4.6.4.1 Technical constraints

Technical constraints include:

- The limitations of existing mining methods and equipment to deal with the geological conditions of a particular coal deposit.
- The relationship between depth, rock strength and mining method is the most important limiting factor contributing to the technical mining prospect of an open-cast or underground deposit.
- Groundwater conditions, geological structure and seam geometry can also have a major impact on the technical mining prospect of a deposit.
- New, large-scale mines are unlikely to be developed unless there is an assured long-term market for the coal.
- Carbon charge may be a significant barrier to further development of the resource, particularly if imported coal does not face the same charge. In recent years, the amount of imported coal has increased dramatically and has reached over 1 million tonnes in some years. If imported coal competes with locally produced coal on price parity, it may be uneconomic to mine coal from some deposits, particularly those that occur in difficult geological settings.

4.6.4.2 Price constraints

Coal is commonly promoted as the cheapest energy source available in New Zealand. This is true for many small and large-scale operations, and it is certainly true that large-scale operations can mine coal at a very competitive price. The extracted product is, however, relatively difficult to transport and other than applications for supplying industrial heat, must be transformed either into electricity or fuels. After the losses in energy associated with conversion, and the costs associated with transport and conversion are taken into account, the overall cost of coal-derived energy is often comparable or more expensive than energy derived from other sources e.g. geothermal, hydro or natural gas. However, not all energy options are available to all consumers e.g. there is no piped natural gas in the South Island, and geothermal energy is confined to the central North Island.

Coal mining costs are increasing in some coalfields as the most easily won coal is extracted. This can be offset to varying degrees by improvements of technology and efficiency.

4.6.4.3 Environmental and social constraints

Some environmental and social constraints to coal mine development include:

- Increasing concerns about the use of coal as a fuel because of its contribution to greenhouse gas production and other atmospheric pollutants.
- Land use conflicts, including balancing the need for energy against preservation of land for agricultural, cultural, scenic or historical reasons.
- The inaccessibility of technically mineable coal resources underlying urban areas and closely underlying significant wetlands, lakes and rivers.
- The costs of managing environmental impacts during mining and carrying out rehabilitation when mining operations end.

An list of relevant externalities was identified in Section 4.6.1.3 – Myth busting.

There is a growing effort globally to apply carbon capture and storage (CCS) technology to coal combustion plant to reduce CO_2 emissions. The technological chain has yet to be used at the scale of a large coal-fired power plant. It is not clear to what extent CCS could be applied in New Zealand, or when. New Zealand has a limited number of ‘capturable’ point sources and, combined with the high costs of CCS, there are currently no incentives to deploy CCS in New Zealand. The Huntly power station and New Zealand Steel are the largest CO_2 emitters, but both are old plant to which retrofitting CO_2 capture is not viable. If CCS is deployed in New Zealand, it is most likely to be in association with CO_2 stripping from gas production or a coal-to-liquids plant based on the South Island lignites.

For coal to be a ‘clean’ fuel, two developments must occur:

- CO_2 recovery technology must be vastly improved
- Secure, long-term CO_2 storage / sequestration locations must be identified

Some recognised barriers to the deployment of CCS are discussed in the Section concerning “Secondary conversion” in this sequence of EnergyScape Asset Review reports. The costs of developing and applying this technology are considerable and New Zealand has yet to identify suitable CO_2 storage locations.

4.6.5 Introduction to conversion technologies

4.6.5.1 Extraction

Coal mining and extraction in New Zealand predominantly based around simple excavators (i.e. industrial scale bulldozers) and heavy trucking – see Figure 4.6.5. For larger scale operations conveyor belts and rail haulage replace the trucking. Processing of extracted coal is generally restricted to that crushing and fines control.

Underground coal gasification (UCG) enables the energy of coal to be recovered without traditional mining. The process involves the injection of oxidants into one end of an unmined coal-seam, and extraction of products via a production well at some distance along the seam – see Figure 4.6.9. The coal seam is ignited via the first well and burns at temperatures as high as 1,230 °C to generate: carbon dioxide (CO_2), hydrogen (H_2), carbon monoxide (CO) and small quantities of methane (CH_4) and hydrogen sulphide (H_2S). Product gases are drawn through the coal seam to the production well. Since the natural permeability of coal seams is often quite low, so several mechanisms are use to break-up the coal e.g. hydrofracing, electric-linkage, and reverse combustion. Progressive burning along the coal face is controlled by the rate and location of oxidant addition. Two methods of UCG are used commercially:

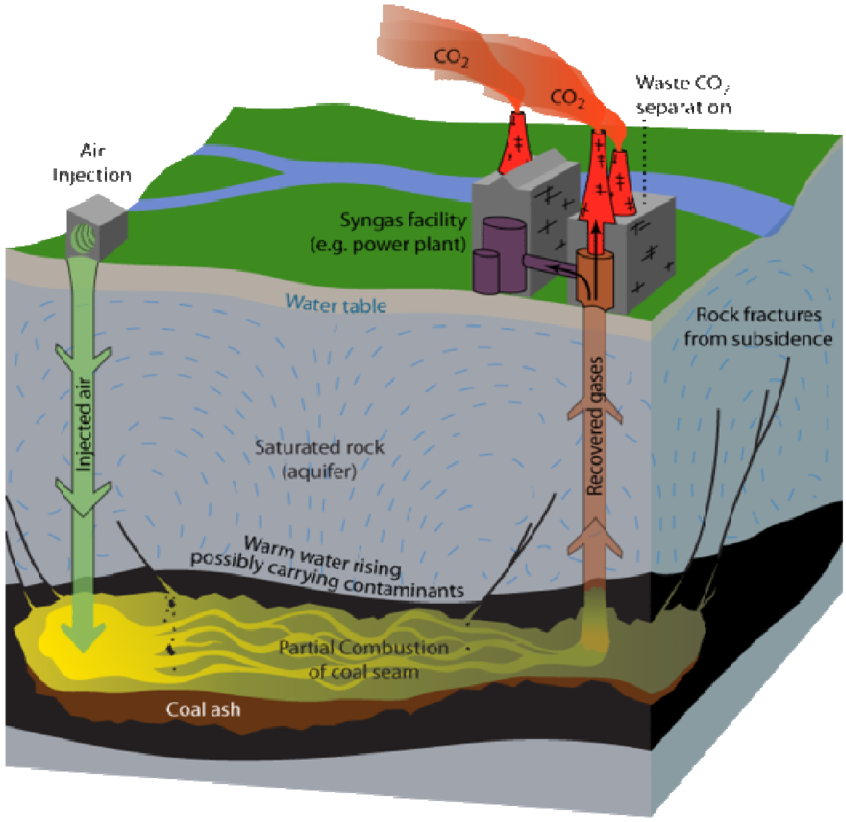
i) A series of vertical wells. This method often uses reverse combustion to break-up the coal and uses air and water as oxidants.

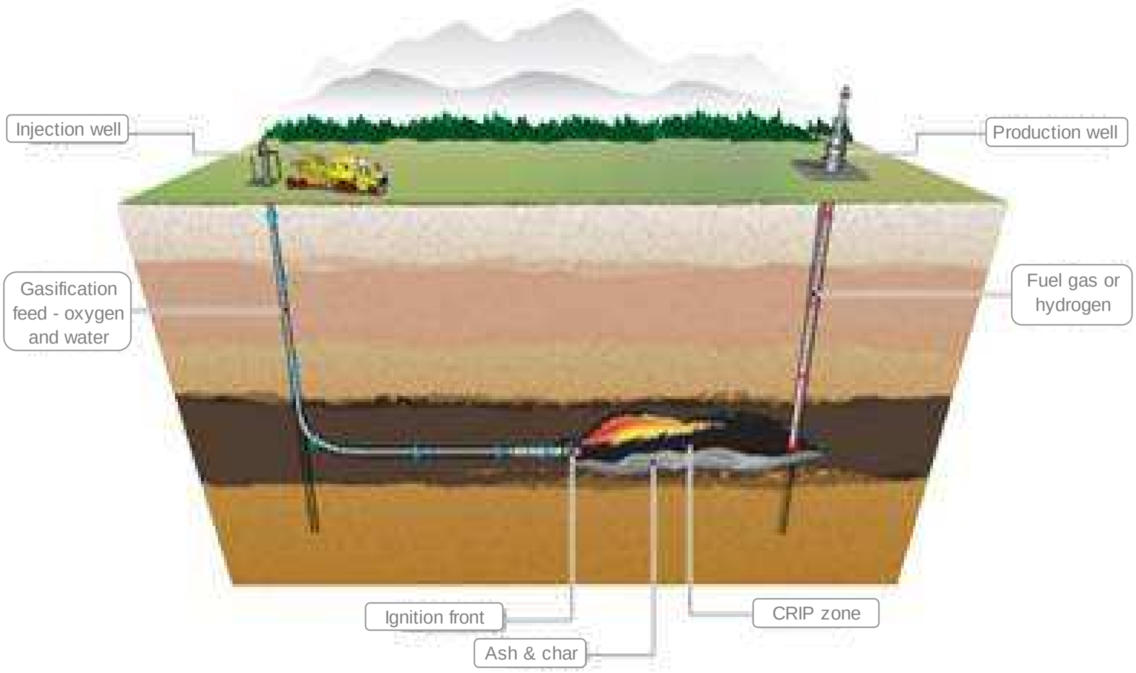
ii) Horizontal drilling with a movable injection point known as CRIP (controlled retraction injection point). This method often uses hydrofracing to break-up the coal and uses oxygen or enriched air as the oxidant.

The technology can be applied when a coal seam lies between 30 and 800 metres underground; has a thickness of more than 5 metres; has an ash content of less than 40%; and, has minimal discontinuities.

Figure 4.6.9 – Two underground coal gasification methods

(top) Spaced vertical wells method; (bottom) Horizontal drilling method.





Source: (top) http://en.wikipedia.org/wiki/Underground_coal_gasification
(bottom) http://www.ucgp.com/key-facts/basic-description/

From the beginning, Russians led development of this technology, with experimental work starting during the 1870s. In 1913, Vladimir Lenin wrote an article about a "Great Victory of Technology" which promised to liberate workers from the hazardous work in the nation's mines, but it was not until 1939 that commercial-scale UCG plants were operating in the Ukraine. Western Europe undertook experimental work between 1944 and 1959, with an attempt at a commercial pilot plant at Newman Spinney in 1958–1959. The US Department of Energy entered the fray in 1972, culminating in the Rocky Mountain 1 trial (1986-1988) that demonstrated exceptional environmental performance. Commercial scale projects have started in Australia[22], China[23], South Africa, India, and the Angren facility in Uzbekistan is still in operation today after more than 20 years of operation[24].

The advantages of underground coal gasification relate to both economics and environmental impact. Because UCG can recover energy products from deep coal seams, it can access coal resources that would not be economically recoverable by traditional technologies. Further, since the products are in gaseous form, the transport of products is often significantly cheaper. Finally, since ash and solid waste are retained underground, restoration costs are significantly lower. Looking forward it can be expected that the lower greenhouse gas emissions (GHG) associated with UCG compared with traditional mining will also increase the economic advantages of UCG.

The environmental benefits of UCG over traditional coal mining include: The elimination of solid waste (e.g. coal ash, oxides, waste rock and radioactive waste) discharge; no need for tailing and ash dams; much reduced visual impairment; reduction in sulphur dioxide (SO_2) and nitrogen oxide (NOx) emissions; and, significant reduction in ash content of end product.

The disadvantages of UCG primarily relate to subsidence and ground water contamination. Underground gasification results in the partial removal of a coal seam less ash. The depth of the void obviously relates to the thickness of the removed seam, but timing of subsidence will be dependent upon the structural integrity of the rock formation that remains. The combustion of coal in a partial oxygen environment yields many organic and often toxic materials (such as phenol) which remain in the underground chamber after gasification. Leaching of these materials into surrounding ground water is an inevitable outcome.

[22] Linc Energy successfully gasified 35,000 tonnes of coal near Chinchilla between 1999-2003.
[23] 16 UCG trials (http://www.coal-ucg.com/current%20developments.html)
[24] http://www.lincenergy.com.au/ucg.php.

4.6.5.2 Secondary conversion

Some of the secondary conversion technology that is identified in the coal pathways (see Figure 4.6.1) include:

- Heat plant
- Electricity generation
- Combined heat and power
- Gasification to hydrogen
- Hydromethanation for SNG production
- Indirect liquefaction
- Direct liquefaction
- Solid oxide fuel cell
- Ethanol production

These technologies are briefly discussed below.

4.6.5.2.1. Heat plant

Coal was being used as fuel from as early as the Bronze Age (3,300 – 600 BC) with more significant use and trade around 200 AD. In its simplest form, yielding heat from coal requires combustion with air. As with most solid fuels, in order to obtain maximum energy yield (i.e. efficiency) from the fuel, the feedstock must be crushed and residence time in the furnace maximised. There are a number of different types of coal combustors, generally set apart by the method used to feed the coal, for mixing the coal and air and for removing the ash. For example:

- Under-feed stokers (limited to plants <8 MW)
- Chain grate stokers
- Coking stokers (low ram stoker, inclined or reciprocating grate)
- Spreader stokers or sprinkler stokers (can cause problems with high particulate emissions)
- Fluidised-bed combustors (can handle a wide range of feed sizes and moisture levels)
- Pulverised coal combustors (used in well over 90% of the coal-fired plants around the world).

The use of air as the co-feedstock in combustion leads to considerable heat loss – all the inlet air must be heated to combustion temperature and only a portion of this heat is recovered before exhausting of flue gas. It is difficult / expensive to recover all of the heat from the flue gas, so a lot of heat is lost. In order to attain maximum combustion efficiency, the quantity of air used in the combustion is carefully controlled. Since >78% of air is nitrogen which is not required in the combustion process, some modern heat plants use oxygen-blown combustion (i.e. they make use of an air separation plant).

The products of combustion include: heat, carbon dioxide, water vapour, carbon monoxide (in varying amounts depending upon the combustion efficiency), sulphur dioxide, oxides of nitrogen (NO and NO_2), particulates, ash and trace metal emissions. To reduce the impact of these emissions on the environment, emission control systems are implemented on larger-scale schemes.

The typical scale of heat plants range from 200 kW (of heat output) to 45 MW[25].

4.6.5.2.2. Electricity generation

When coal is used for electricity generation, it is usually pulverized and then combusted (burned) in a furnace with a boiler. The furnace heat converts boiler water to steam, which is then used to spin turbines which turn generators and create electricity. The thermodynamic efficiency of this process has been improved over time. Simple cycle steam turbines managed to achieve about 35% thermodynamic efficiency for the entire process. Supercritical turbine plants run boilers at extremely high temperatures and pressures and are projected to be able to achieve efficiencies of 46%.

Electricity generation plants are generally significantly larger than heat plants e.g. Huntly Power Station has four 700 MWth coal combustion boilers feeding four 250MWe electricity generators. Overseas electricity plants can yield up to 680 MWe from a single combustion boiler.

4.6.5.2.3. Combined heat and power

The generation of electricity using coal (as described above), yields a large flow of low-grade-heat. Recovery of this heat significantly increases the energy efficiency of the process. For some fuels (e.g. gas and hydrogen), small domestic and industrial scale combined heat and power units are now available. The distribution of coal is much more difficult, hence the opportunities are restricted to large commercial / industrial users which have heat demand co-located with electricity demand e.g. timber drying, district heating, hospital / school heating etc.

[25] “Heat Plant in New Zealand” East Harbour Management, BioEnergy Association, Energy Efficiency and Conservation Authority, May 2004

4.6.5.2.4. Gasification to hydrogen

Coal gasification involves mixing coal with oxygen and steam in a heated and pressurised environment. The reaction produces syngas - a mixture of carbon monoxide (CO) and hydrogen (H_2) gas. If hydrogen is the desired end-product, then syngas is fed into the water gas shift reaction where more hydrogen is liberated.

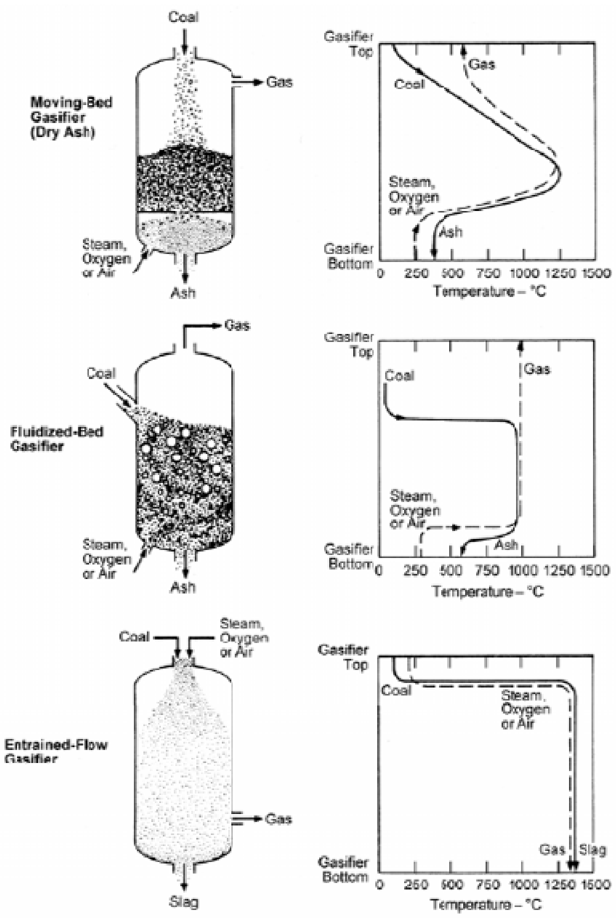
The basic reactions that are occurring are:

$$\text{(Coal)} + O_2 + H_2O \rightarrow H_2 + CO$$

$$CO + H_2O \rightarrow CO_2 + H_2$$

Figure 4.6.10 – Three major types of gasification process

(top) Moving bed gasifier; (middle) Fluidised bed gasifier; (bottom) Entrained flow gasifier



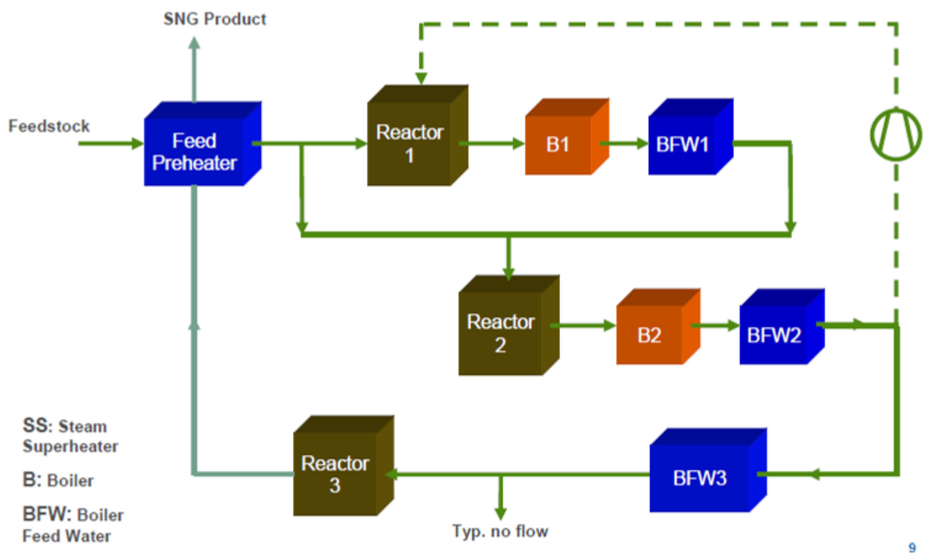
Source: Electric Power Research Institute, 2005

The gasification process was originally developed in the 1800s to produce town gas for lighting and cooking. There were safety issues associated with town gas, hence was replaced by electricity and natural gas. Gasification today is primarily utilised for the production of synthetic chemicals and fuels. The three major types of gasification processes are summarised Figure 4.6.9.

4.6.5.3 Hydromethanation for synthetic natural gas production

Coal hydromethanation uses the same gasification concepts as outlined above, but shifts the operating conditions towards the yield of methane rather than hydrogen. The process is increasingly receiving attention because it recovers the energy contained within coal, but with a reduced carbon penalty (i.e. CO_2 can be reduced). Methane recovery is maximised by use of multiple reactors (with recycle) operating at high pressure (~1000 psig, 69 barg) and low outlet temperatures. Introducing additional feedstock into the second stage also has advantages. A typical flow diagram for a methanation system is provided in Figure 4.6.11.

Figure 4.6.11 – Typical hydromethanation process flow



Source: Lurgi, 2008[9]

The product of hydromethanation is synthetic natural gas (SNG). This product could be distributed by pipeline to the conventional natural gas users.

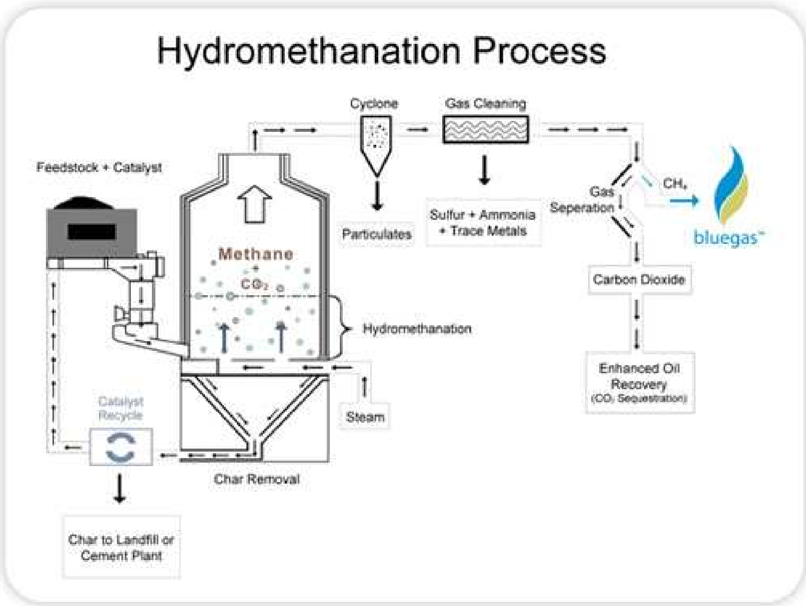
The following reactions are important to hydromethanation coal gasification:

$$(Coal) + O_2 + H_2O \rightarrow CH_4 + CO + CO_2 + Oils + Tars + C\ (Char)$$

$C + O_2 \rightarrow CO_2$	(exothermic – rapid)
$C + ½O_2 \rightarrow CO$	(exothermic – rapid)
$C + H_2O \rightarrow CO + H_2$	(endothermic – slower than oxidation)
$C + CO_2 \rightarrow 2CO$	(endothermic – slower than oxidation)
$C + 2H_2 \rightarrow CH_4$	Direct methanation (exothermic)
$CO + 3H_2 \rightarrow CH_4 + H_2O$	Methanation (exothermic)
$CO + H_2O \rightarrow CO_2 + H_2$	Shift reaction (slightly exothermic)

Simplifier hydromethanation schemes have been proposed for smaller scale developments – see Figure 4.6.12. These plants use a single reactor and can still achieve efficiencies between 55 and 65%, and up to 50% CO_2 recovery.

Figure 4.6.12 – Single stage hydromethanation demonstration plants



Source: (left) www.greatpointenergy.com
(right) Güssing 1MWth demonstation plant (http://www.eee-info.net/cms/EN/)

4.6.5.4 Indirect liquefaction

Indirect liquefaction involves a multi-step process, the first of which is the gasification of coal to make syngas. Gas to liquids (GTL) technologies are then used to convert gas into transport fuels. The most recognised GTL process is the Fischer-Tropsch process. In this process, passing syngas over catalysts yields light hydrocarbons (like ethane) which, with further reactions, are processed into heavier hydrocarbons. Conventional distillation can then be used to separate out a suite of high value transportation fuels such as jet fuel, petrol and diesel.

Syngas can also be converted into gasoline (i.e. petrol) using the Mobil MTG process. Syngas is first converted to methanol. Passing syngas over a catalyst of copper, zinc oxide, and alumina at 50–100 barg and 250°C produces methanol ($CO + 2\ H_2 \rightarrow CH_3OH$). The methanol is then subsequently polymerised, using a zeolite catalyst, into alkanes (i.e. petrol).

Indirect liquefaction technology and asset characterisation is discussed in Section 6 – Secondary conversions.

4.6.5.4.1. Direct liquefaction

Pyrolysis is the spontaneous thermal decomposition of organic materials in the absence of oxygen. The process produces a cloud of persistent smoke-aerosol and volatile gases, some of which can be condensed into a low-grade liquid fuel (i.e. bio-oil). The efficiency of bio-oil formation is governed by flash temperature and furnace residence time. Bio-oil resembles a light crude and would need to be refined to yield higher-grade transport fuels. Direct liquefaction technology and asset characterisation is discussed in Section 6 – Secondary conversions.

4.6.5.4.2. Solid-oxide fuel cell

Fuel cell technology is still evolving rapidly. Currently this technology can only process gaseous fuels, and cells are often sensitive to sulphur poisoning, but in principle fuels cells do not discriminate between fuels and only need a fuel which can oxidise. Some fuel cell concepts which could use coal as a fuel include:

i) Solid-oxide fuel cell (SOFC)

ii) Molten-carbonate fuel cells

iii) Pulverized coal in a gas carrier, such as nitrogen.

These technologies could yield high energy-efficiencies (65-80% of energy converted to electricity and heat) and could be used either to generate electricity or hydrogen depending on favourable pricing. This technology is discussed in Section 7 – Hydrogen options.

4.6.5.4.3. Ethanol production

Two processes for producing ethanol from coal are known:

1. Huls Arc Process (Weissermel et al., 2003) reacts coal and natural gas in the presence of an electric arc to produce a mixture of acetylene and ethylene gases. Subsequent hydration of ethylene with steam yields ethanol.
2. Syngas (produced from the gasification of coal) can be used by the anaerobic bacterium *Clostridium ljungdahlii* to produce ethanol and acetic acid in relatively high concentrations.

4.6.5.5 Non-energy

New Zealand coals have some unique qualities that make them well suited for coke making. At present there is no coke making carried out in New Zealand but coal is exported for this purpose.

The largest non-energy use of coal in New Zealand is the production of steel, and Solid Energy has proposed making fertiliser from lignite. Natural gas is currently the preferred feedstock for this process. More detail regarding the use of coal for non-energy purposes is detailed in Section 1 – End-use characterisation.

4.6.5.6 Carbon storage and sequestration

Carbon capture and storage (CCS) would be a key partnering technology to all the coal conversion processes (conventional and advanced) should stringent climate change initiatives be introduced. Please refer to Section 6 - Conversion technologies, for more detail on this technology.

4.6.6 Asset characterisation

It is very difficult to characterise the costs of coal extraction and processing using a bottom-up approach since costs are dominated by operating costs and are very location specific. To overcome this difficulty we back-calculated operating and capital costs based on raw coal sales prices, where capital costs were considered to only be 20% of total operation costs.

Modern, small scale (1 to 10 MW) coal combustion boilers are expected to operate with an energy efficiency of around 80 – 85% (steam or heat energy out versus coal energy in), but installed boilers in New Zealand may only be operating at around 65% efficiency due to their poor operation. The costs of these small-scale plants can vary considerably. As an indication, $3 million for capital and installation of a 10 MW capacity steam-raising plant is not unreasonable. Operating and maintenance costs typically run at around 10% of capital (i.e. $300,000 per annum for 10 MW steam plant). For a somewhat larger-scale plant of, approximately, 30 MW with combined heat and power capability, a capital and installation cost in the order of $15 million may be incurred with operating and maintenance costs of approximately $1.5 million per annum.

Application efficiencies range from near 100% for the conversion of steam heat to hot water, to 32 – 42% for electricity generation (and around 35% for the likes of the 1,000 MW-scale Huntly power station). A supercritical, pulverised coal-fired plant typically achieves around 42 – 45% efficiency in terms of coal energy in versus electricity produced, reducing to an estimated 36% if carbon capture and storage is also included.

Asset characteristics for New Zealand's boilers and electricity generation plants have been based either on data contained in the Electricity Commission's Generation Expansion model[26] and East Harbour Management Systems industry costing reports[27].

Coal has a high yield of GHG emissions per energy yield – typically 89 kt CO_2/PJ for bituminous coals, 91.2 kt CO_2/PJ for sub-bituminous coals, and 95 kt CO_2/PJ for lignites.

Most of the proposed future large scale coal conversion assets could be designed to incorporate carbon sequestration. The products of these conversions (e.g. ethanol, petrol, diesel) will still release GHG emission upon combustion, but some of the carbon that is recovered from these processes may be sequestered. In this way, the products of CTL technology may have a similar carbon footprint as conventional fuels, or lower if biomass is used as co-feed.

[26] http://www.electricitycommission.govt.nz/opdev/modelling/gem
[27] http://www.med.govt.nz/upload/9098/fossilfuel.pdf and http://www.eastharbour.co.nz/publications.html

4.6.6.1 Emerging trends

New Zealand's gas reserves equate to around a decade of consumption, although there is a high probability that new fields will be discovered. Until that happens, the New Zealand energy sector is in a period of transition from the Maui era of abundant and cheap natural gas to the post-Maui era which will follow field depletion.

Bituminous coal mined and exported from the West Coast for use in steel-making is – and is likely to continue to be - a high value commodity because of its desirable qualities – high to very high swelling values, low ash content, and low levels of deleterious elements. Only modest quantities are available and it is unlikely that bituminous coal will make a major contribution to New Zealand's energy supply.

Waikato coal plays a major part in New Zealand electricity generation, providing from the Huntly site almost 1000 MW of base load electricity to underpin demand from nearby Auckland, New Zealand's major city. Constraints on gas supply and price considerations resulted in the Huntly station being switched from burning mainly natural gas to burning coal, from both local mines and imports. The Huntly coal-fired plant is New Zealand's largest single electricity generating station and with no obvious substitute on the horizon, coal burning at Huntly is likely to be necessary for at least the next decade, with attendant emissions of greenhouse gases.

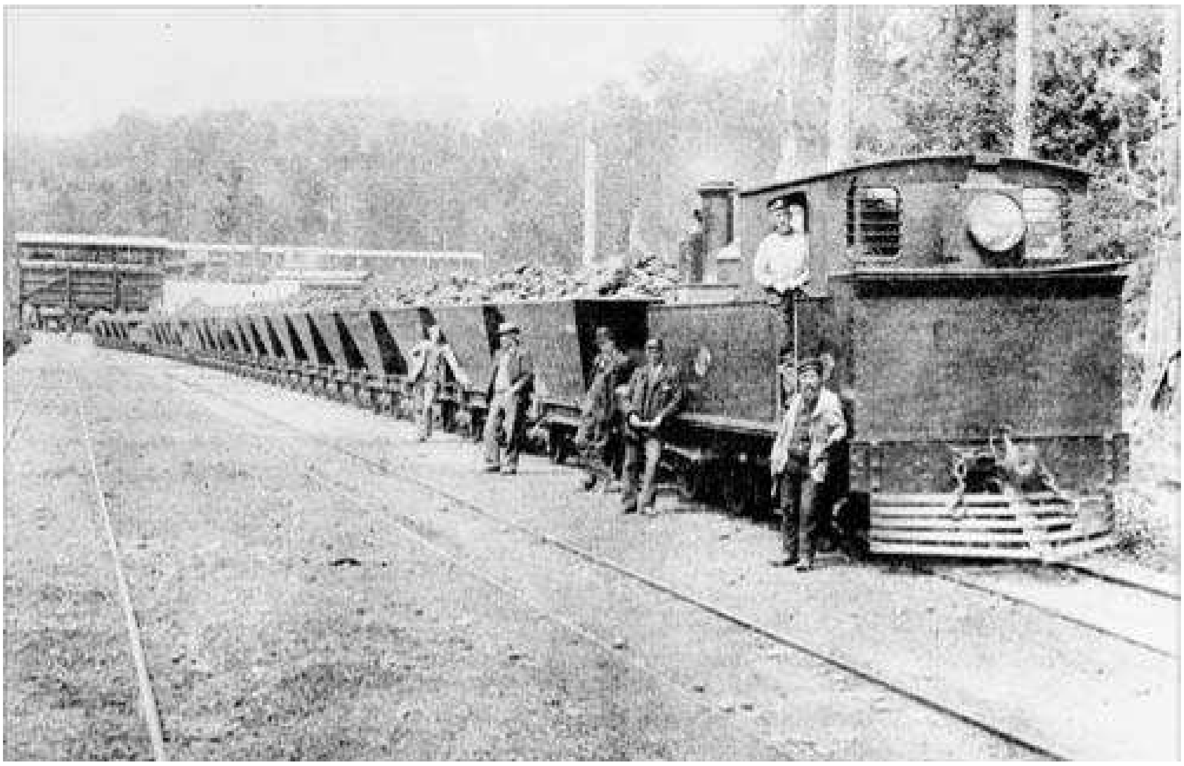
The two major customers for Waikato coal are Huntly power station and the Glenbrook steel mill. However, the opencast (and therefore relatively cheap) sub-bituminous coal reserve at or close to the specification preferred by the power station and particularly the steel mill is limited. If opencast reserves at Waikare are not exploited, in future, a greater proportion of the coal will have to come from underground mines beyond and deeper than the present underground operations and the price will be higher. Alternatives include adapting to burn slightly lower rank coals mined elsewhere in the region (e.g., Maramarua) or relying more heavily on coal imports. Imported coal can probably be landed in New Zealand at a price competitive with local underground production.

Serious consideration is already being given to the large-scale exploitation of Southland and Otago lignite. The possibilities include lignite to gas or liquids, fertiliser production, thermal power generation, or a combination of these. The total resource is very large – many times the original energy content of the Maui gas field – but how much of this can be mined at costs which are economically and socially acceptable is uncertain. Much is at depths of more than 100 metres, in relatively thin seams separated by laterally persistent aquifers, underlying land valued for agriculture. Vast, thick, near-surface lignites of Victoria, Australia can be mined more cheaply.

However, there is a high probability that a large scale opencast mine in Southland or Otago could, for decades, produce millions of tonnes of lignite a year cheaply enough to be attractive for thermal power generation and, perhaps, production of transport fuels. To do so would require mining at a scale not previously seen in New Zealand, with consequently large environmental impact. Mine and plant would require a very large capital investment; a key factor likely to influence potential investment will be the possibility that a lignite development could be undercut by a future gas discovery in the Great South or Canterbury basins.

Figure 4.6.13 – Echoes from the past

Seddonville coal train in 1893



Source: www.teara.govt.nz

4.6.7 Research status

Much of the large-scale combined plant (coal combustion plus application) research is of high-cost. New Zealand is, thus, more likely to purchase the technology from overseas and adapt it to New Zealand coals and applications. The suggested New Zealand 'adaptation research' includes:

- Improving upon the performance of existing plant through better calibration and operation
- Adaptation for co-firing or conversion of existing plant to enable increased use of biomass feedstocks
- CHP, including adaptation of existing plants
- Underpinning scientific study of the specific characteristics of New Zealand coals under the prevailing conditions of new coal-combustion technologies
- Adaptation of plant to capture CO_2 from the exhaust streams.

Recent research has focussed on technologies related to the utilisation of coal. A range of technologies that promote more efficient use of coal and minimise the environmental impact of its use are under investigation. Important research areas include work on the extraction of hydrogen and liquid fuels from coal deposits, the capture of carbon from coal combustion gases and the feasibility of long-term geological storage of extracted CO_2.

Although coal combustion is a mature technology, there are many large-scale research, development and demonstration activities underway worldwide to improve the efficiency, reduce and manage by-products and increase the use of biomass co-firing. These include research into:

- "Clean coal" technologies, which look to capture the greenhouse gas emissions and store them. These technologies include oxyfuel burning where near pure oxygen is used for combustion, rather than air, providing a more concentrated exhaust stream from which to separate carbon dioxide.
- Co-firing with biomass or wastes. This has the potential to possess a far lower carbon footprint than for firing by coal alone and becomes particularly attractive if combined with carbon capture and storage.
- Pressurised, pulverised coal and pressurised, fluidised-bed combustion technologies, which aim to improve upon the energy efficiency of coal-based thermal generation plant by producing a hot, high-pressure combustion gas stream for direct use in a gas turbine.
- Combustion of very fine, ash-free, washed coal that can be used directly in gas turbines.
- Supercritical and ultra-critical plant technologies (i.e., very high pressure and temperature), which aim to improve upon the energy efficiency due, primarily, to the high-pressure steam cycles used.

The South Island lignite deposits are large enough to support large-scale petrochemical processing into a range of energy products (hydrogen, diesel, jet fuel, methanol, ammonia, urea, etc.). Research into the feasibility of such processing is being evaluated. First stage studies into options for carbon capture and storage have been completed.

There is quite extensive research carried out by coal mining companies into mining techniques. While New Zealand is to some extent a technology taker in this respect, dealing with sometimes severe geological conditions has required extensive desk top and practical research. Examples are the adaption of 3D seismic for geological interpretation and mine modelling and the use of hydro mining (water jet coal cutting).

Table 4.6.14 – Research status

(Clear indicates 'Fair knowledge', Green highlight indicates 'Potential opportunity', Amber indicates 'Could improve', Red indicates 'Knowledge gap exists')

	International	New Zealand	Comment
Resource mapping	Mature	Mature Coal companies, MED, GNS	Well understood at most levels and most localities.
Mining technology	Mature	Variable Solid Energy, Pike River, others	Advanced feasibility studies applied to some operations.
Underground coal gasification (UCG)	Immature	Immature Solid Energy CRL Energy, Uni. Cant	May provide partial indigenous gas and oil substitute from syngas.
Hydromethanation	Immature	Immature CRL Energy, Uni. Cant	May provide a basis for indigenous gas and oil substitution. Can support biomass gasification.
Pyrolysis	Immature	Immature CRL Energy	May provide a basis for indigenous gas and oil substitution.
Light, conventional fuel synthesis	Immature	Advancing Solid Energy, L&M, CRL Energy	New Zealand should be ready to learn from the results of large-budget research projects overseas.
Carbon capture and storage potential (Geo-spatial)	Advanced CRC	Emerging FRST, GNS, Solid Energy	New Zealand is evaluating storage capacity.
Carbon Capture and Storage (Technological)	Advancing O&G consultants	Advancing Genesis; O&G consultants	Flue gas extraction and compression is relatively mature technology.
Consenting rules	Mature for some jurisdictions	Immature Ministry of Economic Development	Need for standardised guidance to support RMA. Need mechanism for allocation rights (CMA)

4.6.8 Summary

Coal is New Zealand's most abundant fossil fuel resource. Recent annual production has reached 5 Mt, with most coming from the Waikato and West Coast regions. Almost half is exported and domestic consumption is dominated by thermal power generation and iron / steel processing. The extent of New Zealand's coal resource is comparatively well known, mainly due to the comprehensive Coal Resources Survey carried out by the Government between 1976 and 1989. The total in-ground resource is estimated to be about 15 billion tonnes, with the majority located in the lignite deposits of Southland and Otago. Apart from the lignites, most estimates of recoverable coal are uncertain, as many of the factors affecting recoverability are not fully evaluated. Although New Zealand's coal resource is very large, there are significant barriers to increased use of the resource. These include a range of technical constraints to mining, the difficulty of bringing new mines on-stream to meet rapid changes in demand, market uncertainty, the price currently set by coal imports and increasing environmental concerns about the use of coal.

At present, coal production is increasing and is driven by two principal markets:

- International demand for premium bituminous coal from the West Coast
- Increased use of sub-bituminous coal for electricity generation at Huntly.

The demand for export coal is likely to increase, but the supply will be limited by existing rail and port facilities. While there is uncertainty about future gas supplies, the use of coal for thermal power generation is likely to continue and may even increase. Large-scale utilisation of the South Island lignite deposits warrants serious evaluation. New Zealand's coal resources could contribute to balancing the needs of energy security, economic competitiveness and value of fuel diversity in the highly energy-dependent New Zealand economy.

However, the contribution of coal combustion to greenhouse gas emissions will need to be addressed and mitigated if coal utilisation is to increase significantly. Capture and geological sequestration of CO_2 is one of the options under investigation that could allow energy production from coal to continue with greatly reduced CO_2 emissions.

Section 4.6
Nuclear energy

4.7 NUCLEAR ENERGY

4.7.1 General introduction

The development of nuclear energy represents both opportunity and risk. If nuclear fusion could be achieved safely and economically, an enormous resource would be available with limited direct environmental impact. In the late 1970s / early 1980s nuclear fission was heralded as a cheap and relatively benign electricity source. Subsequent difficulties associated with spent fuel disposal, leaks and contamination have challenged the economic justification and signalled the great risk to the environment of this technology.

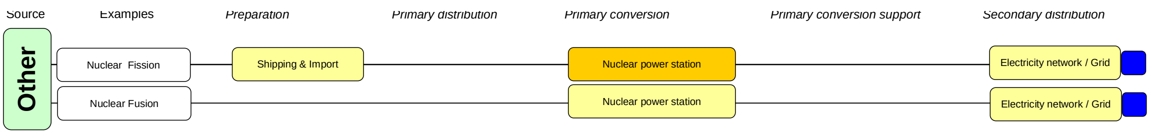
A pellet of uranium, weighing around 7 grams, can generate as much energy as: 3.5 barrels of oil, 480 cubic metres of natural gas, or, 810 kilograms of coal.
***Source*: Uranium101, Cameco**

The application of either of these technologies in New Zealand could be significantly limited by the lack of redundancy in our electricity transmission system, and operational difficulties associated with a large single shaft generator. Considering that New Zealand has no viable nuclear fuel resources, nor regions suitable for the safe disposal of nuclear waste, this technology is not a natural fit.

4.7.1.1 Pathways

There are only two common pathways through which nuclear energy may be harnessed and supplied in a useable form, and only one of these, nuclear fission, is feasible for New Zealand.

Figure 4.7.1 – Nuclear energy pathways



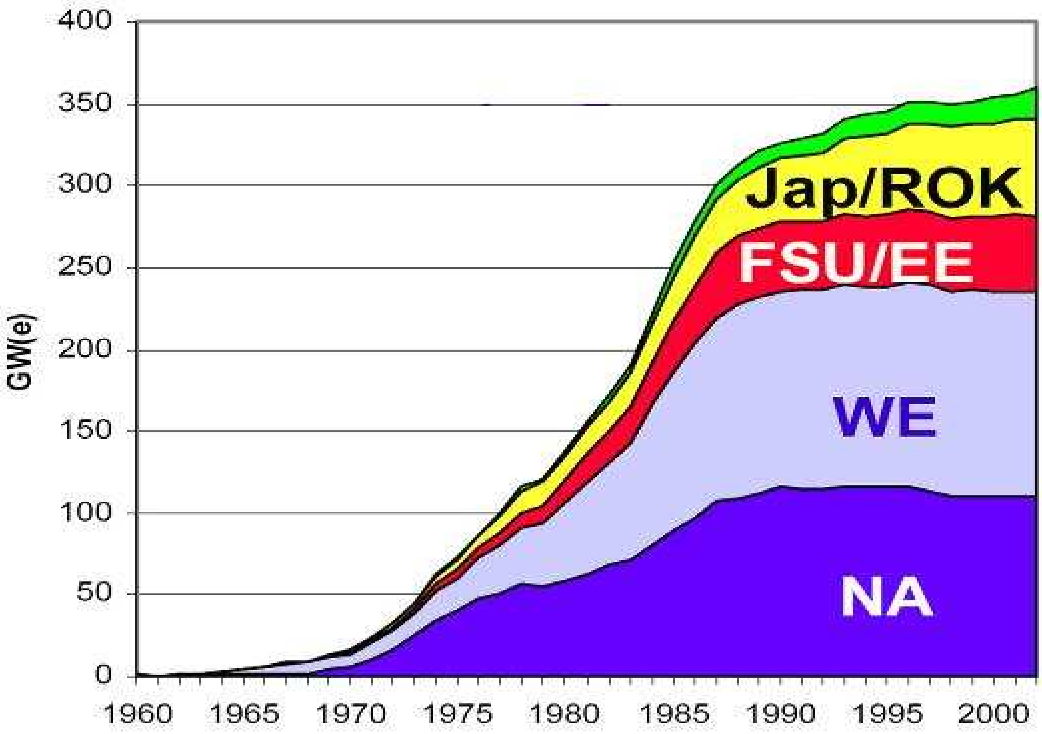
A full view of the pathway is presented in the Pathway Overview Map at the start of this document.

Nuclear fission, the process of splitting large atomic nuclei into smaller components releasing a significant amount of energy, was first discovered in the 1930s. However, it was not until 1951 that electricity was first generated from nuclear power [Wikipedia (2008a)]. Figure 4.7.2 shows the geographical distribution and timeline of nuclear power installations around the world. This figure indicates a flattening out of the generation capacity beyond 1988, as more than two-thirds of all nuclear plants ordered after January 1970 were cancelled [Cohn (1997)]. Recent developments in new nuclear power generation procurements have been described as a "nuclear renaissance" [Newton-Small (2005)] because this technology represents a possible solution to impending perils of 'peak oil' and 'climate change'.

Nuclear fusion, the process of fusing small atomic nuclei into larger components, and thereby releasing a significant amount of energy, is still in its experimental stages.

Figure 4.7.2 – Timeline of nuclear power plants

The global installed nuclear capacity in GW(electricity).
FSU: Former Soviet Union. EE: Eastern Europe. NA: North America. Jap: Japan. ROK: Republic of Korea. WE: Western Europe.



Source: IAEA (2002)

4.7.1.2 Scale

Early commercial nuclear power stations achieved electrical generating capacities in the region of 50 – 200 MW (e.g. Sellafield, UK), and modern, commercial, plant designs are available from 600 MW up to 1,700 MW. In the UK and central European economic context, the 600 MW reactor design represents the minimum feasible power output requirement for a new generating plant. If the same economic situation was true for New Zealand, this “entry level” scale of the plant would already be too large for the national electricity generating system and distribution grid to cope with. The reason for this that the large single shaft generation associated with a nuclear plant would need to have an equivalent scale of conventional power generating capacity to be permanently available during their operation. The conventional plant maintains a “spinning reserve” of potential power generating capacity in order to provide instantaneous back-up power for when the nuclear plant encounters a fault. With the small-scale of the existing national electricity system in mind (having three, major, conventional generating plant with capacities of approximately, 400 MW each), the associated operation of a further 600 MW of spinning reserve in addition to the nuclear power plant capacity is a significant, added burden. While enough spare generating capacity may be available in New Zealand’s hydro dams, this back up would only be available for a few weeks rather than months as required, and transmission constraints may limit the scope of this option.

Nuclear power engineering companies are working on a "fourth generation" of nuclear plant, which they believe will be cheaper, safer to operate and will provide the prospect of smaller-scale plant. However, such plants are not expected to be available "off the shelf" for a decade or more.

Conflicting with this drive towards smaller-scale nuclear plant is the fact that economic viability must rely on maximising the scale in order to overcome the sizeable, minimum costs associated with the safe operation and maintenance of the plant and the long-term issues associated with waste material storage [Contact Energy (2008)].

4.7.2 Introduction to the resource

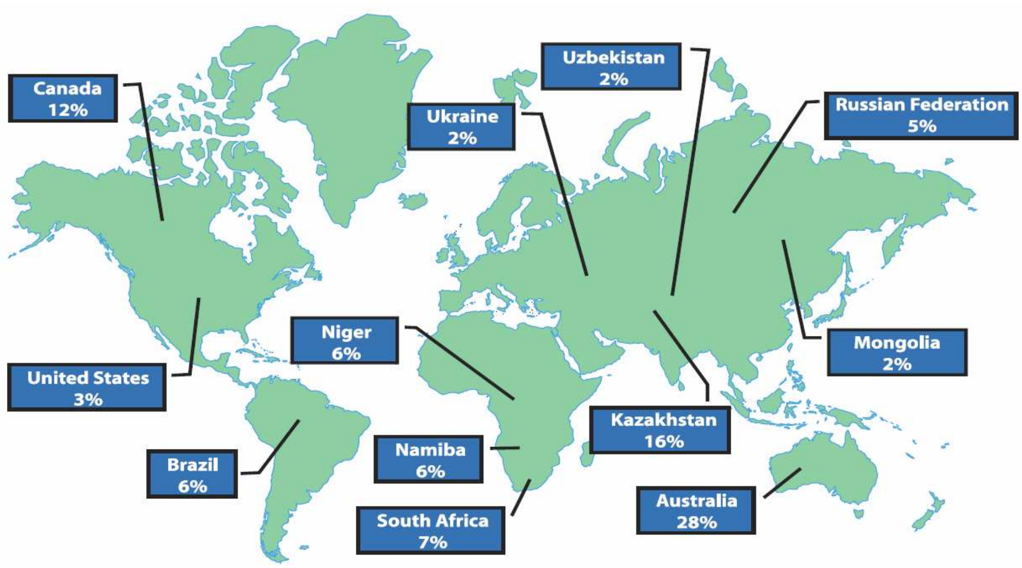
The most abundant isotope in Uranium oxide is Uranium-238 (99.28% of the natural occurrence). This isotope is called “depleted” Uranium and is not suited for fission. Rather, the Uranium-235 (0.71% of natural occurrence) and Plutonium-239 isotopes are used.

The fission of one Uranium-235 nucleus releases 50 million times more energy than the combustion of a single carbon atom.

***Source*: Uranium101, Cameco**

Enrichment of the uranium ore is required in order to increase the concentration of fissionable Uranium-235, before it can be used in nuclear reactors [Wikipedia (2008b)]. Plutionium-239 can be manufactured from Uranium-238 with “breeder” reactors, thus generating a secondary source of fissionable fuel for further nuclear power processes. Figure 4.7.3 indicates the distribution of major, naturally occurring, Uranium resources around the world.

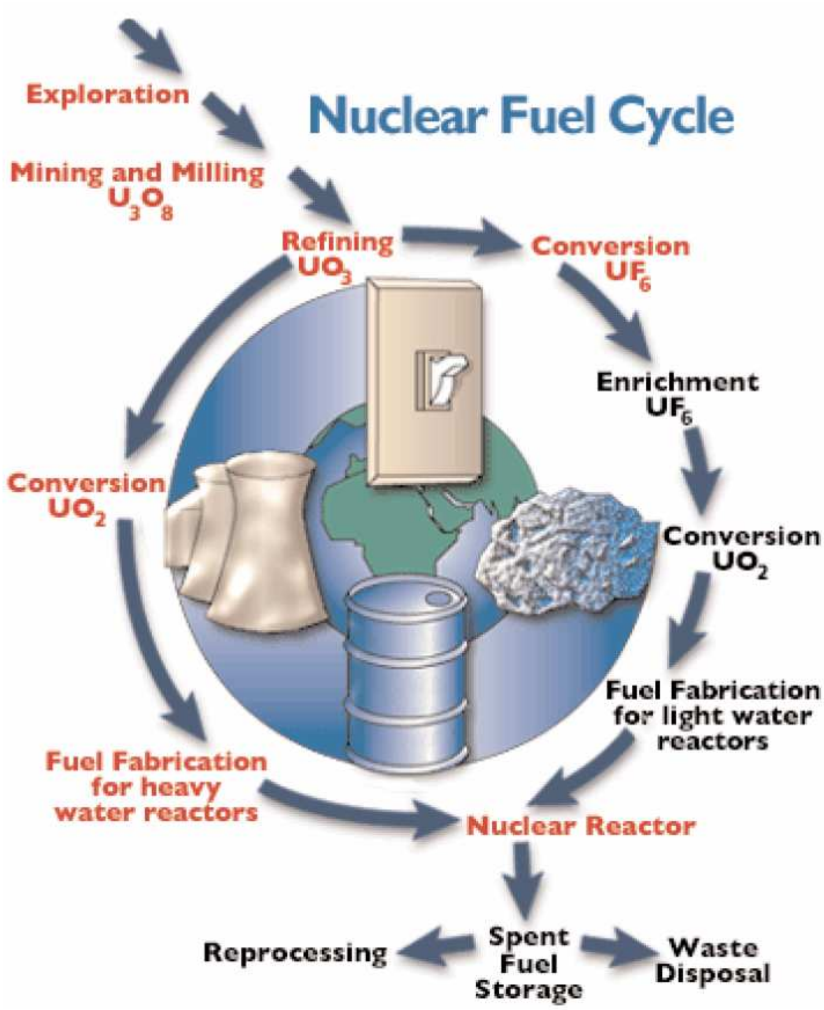
Figure 4.7.3 – Distribution of major Uranium resources across the world.



IAEA, Uranium 2005, Resources, Production and Demand, published by OECD.

The ten major Uranium sources indicated in Figure 4.7.3 are responsible for 95% of the world's total Uranium extraction, and, in 2007, the world production of Uranium ore (U_3O_8) was around 49 thousand tonnes [Cameco (2008)]. There are a number of secondary sources of fissionable Uranium. Currently mixed oxide (MOX) fuel, produced by down blending highly-enriched uranium (HEU) during nuclear weapons disposal, and re-processed uranium fuel (Figure 4.7.4) is available. Conflicting views exist regarding the extent of remaining nuclear fuel reserves. The IAEA estimates that at present consumption levels, the world is not going to run out of Uranium fuel for many centuries [IAEA (2005)]. Contrary to this view the Energy Watch Group of Germany (EWG) estimates that production of nuclear reactor fuel can not be increased beyond 2040, at which time the production will head into steep and irreversible decline (EWG 2006 "Uranium resources and nuclear energy" Report December 2006). This pessimistic view of insufficient production (mining) of reactor fuel is reinforced to a certain extent by the fact that currently ~⅓ of nuclear fuel demand is supplied from stock draws and nuclear weapons disposal (MOX fuel), which will cease shortly.

Figure 4.7.4 – Uranium supply cycle



www.cameco.com, Uranium 101

4.7.3 Barriers and limitations

New Zealand does not have any significant, indigenous sources of Uranium-235 and would need to buy nuclear fuel on the international market. This lack of internal resource means that there is no reduction in exposure to price fluctuations on the international Uranium fuel market for New Zealand.

The most obvious barrier to the adoption of nuclear power in New Zealand is that the technology is fundamentally unacceptable for many people. Opposition to military and civil nuclear technology has played an important role in New Zealand's recent history, and has become part of this country's identity. However, future energy development options need to be reviewed with a more rational approach.

Another barrier is the risk of nuclear accidents, however large or small (e.g. ranging from safely contained radio-active material spills and leaks to full-scale reactor core melt-down, as observed in the Three Mile Island and Chernobyl reactor accidents). The risk profile involved in these accidents makes it difficult for this power generation option to be compared with others, as it involves extremely low probabilities of accident occurrence coupled with extremely high levels of resulting damage. Nuclear facilities have, recently, been identified as possible terrorist targets, adding a further levels of associated risk.

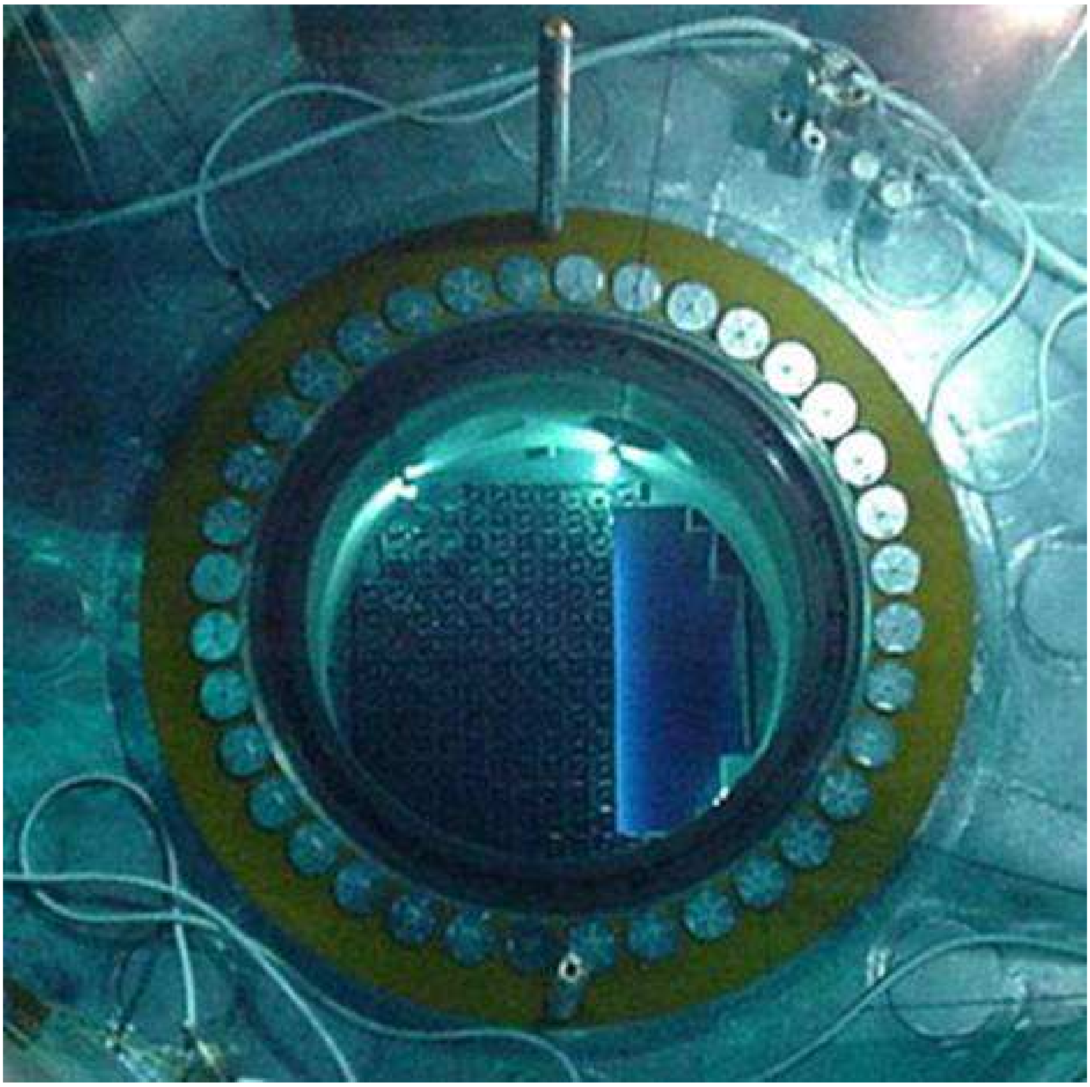
The long half-life of some of the fission products generated in a nuclear reactor introduces an intergenerational aspect to nuclear waste management. However, as there are few greenhouse gas emissions associated with nuclear electricity generation, it is suggested that nuclear power should play an increasing role in meeting the world's future electricity requirements. [NEI (2008)]

Although the concerns above play major roles in discussions of the 'nuclear option', there are other, less obvious, aspects that can be decisive, such as the significant commercial risks and technical difficulties involved with the implementation of nuclear power schemes. Concerns around the cost of nuclear energy also play a role. Nuclear power plants typically have low fuel costs in comparison to the high capital costs of the plant. There also remain large uncertainties in the cost of decommissioning the plant and "disposing" of waste materials at the end of the plant life.

The technical issues mostly relate to the integration of nuclear power stations into the electricity network, where even a small 600 MW single-shaft-turbine unit is considered to be very large by New Zealand standards. The largest turbines currently operated within New Zealand are Contact Energy's Otahuhu B gas-fired power station, of 380 MW, and Genesis Energy's e3p, 385 MW unit at Huntly. Adding a single-shaft 600 MW unit to New Zealand's electricity grid will introduce operational difficulties, including management of spinning reserve and dispatch of electricity into the network [Woodward (2008), Contact Energy (2008)].

It is also argued that adding nuclear power to the national generation portfolio requires a new government agency or 'nuclear regulator' to be created in New Zealand, similar to the electricity commission. A meaningful indemnity insurance for a nuclear power plant negotiated between the operator and a commercial insurance company might increase the cost of electricity generated to levels which would make nuclear generation uneconomic. Insurance cover would probably need to be provided by the government, as is done in one form or another in every overseas country using nuclear generation. Placing such a burden on the government could spark political controversy; it would complicate and delay implementation of a nuclear generation scheme.

Some of the barriers listed above may be overcome at high cost and with a strong political will. The economics of nuclear power generation are not very clear, but a number of factors indicate that nuclear generation schemes are economically not very competitive when compared to other, less risky, energy options. In any case, planning, construction and commissioning of a nuclear power plant, even without local-resident's opposition, will take at least a decade, and therefore can't be considered as a "quick-fix" to shorter term electricity shortages.



Nuclear reactor core www.sciam.com

4.7.4 Introduction to the conversion technology

There are only three forms of reactor technology in serious contention in the UK, Europe or the US [E&T (2008)]:

- Light Water Reactor (LWR) in two forms:
  - Pressurised Water Reactor (PWR);
  - Boiling Water Reactor (BWR), and;
- Heavy Water Reactor (HWR)

Most reactor designs are based on a Westinghouse or General Electric design. Modern forms of these designs are categorised as Generation III or III+. Generation III designs are advanced reactors developed during the 1990s. Generation III+ are yet more recent developments, intended for deployment by 2010 [Woodward (2008)]. The latest designs share the following common features: improved safety systems; modular design to reduce costs and shorten construction times; increased fuel burn-up to improve efficiency and reduce nuclear waste volumes and larger unit size to improve economic competitiveness. An important point to note is the vast amount of effort and resources required for the completion, and certification of a particular reactor design.

The cost of nuclear electricity generation is notoriously difficult to estimate, and initial cost projections have very often been far too low. Most difficult in this regard is the decision regarding which indirect costs (e.g. cost of nuclear waste disposal) have to be included in a cost calculation. The construction costs of a nuclear power plant are substantial and increasing rapidly. The construction costs for the 1600 MW pressurised water reactor Olkiluoto 3 currently being built in Finland will most likely have amounted to €4,500 million (NZ$10,000 million) by the time it is commissioned in 2011 (initial cost estimate €3,000 million) (Telepolis 2008), which would indicate a capacity cost of NZ$6,250/kW[28].

Recent estimates for the marginal cost of nuclear generation vary widely. A US government study (EIA 2006) projected a marginal cost of generation of US$0.059 /kWh (NZ$0.099 /kWh), for new nuclear generation schemes; however this study assumed a construction cost of US$1,984/kWh (NZ$3,307/kWh), which in light of the figures from Finland appears far too optimistic. A 2008 study considering historical nuclear performance trends (Severance 2008) indicates a marginal cost of 0.42 – 0.5 NZ$/kWh for new nuclear power generation schemes in the US.

[28] As a comparison, other electricity generation asset capital costs are typically: 2500 – 3500 $/kW for wind; 4000 – 4800 $/MW for geothermal; and 2000 – 2600 $/MW for coal.

4.7.5 Asset characterisation

Nuclear power generation is not included in the asset database used for scenarios in the LEAP model.

4.7.6 Research status

New Zealand should keep a watching brief on the progression of nuclear generation activities in Australia, since it may be possible to lever technology and skills from across the Tasman.

Table 4.7.5 – Research status

(Clear indicates 'Fair knowledge', Green highlight indicates 'Potential opportunity', Amber indicates 'Could improve', Red indicates 'Knowledge gap exists')

	International	New Zealand	Comment
Fission generation	Mature		May be able to develop if Australia advances nuclear fission generation plans
Fusion generation	Immature	Technology is still immature	Technology is still immature

4.7.7 Summary

A discussion on whether to employ nuclear power generation in New Zealand often becomes a discussion of the risks of nuclear accidents and of historical, political precedence. However, beyond this the implementation of nuclear power generation suffers from significant commercial risks and technical difficulties involved in its integration with the national grid.

The economic viability of a nuclear power plant is dependent upon its size. If a 600 MW power plant is deemed the smallest economically feasible, integration of this size of single-shaft-turbine into the electricity grid will introduce operational difficulties, including management of dispatch of electricity and spinning reserve.

In addition, high capital costs of development of the nuclear power plant and large uncertainties surrounding the costs of decommissioning and waste disposal still exist.

Considering these issues in light of alternative energy technologies makes this an unlikely option for New Zealand.

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Glossary

GLOSSARY OF COMMON TERMS

~	Approximately
Afforestation	To convert land into a forest by planting trees or their seeds.
ADCP	Acoustic Doppler Current Profiler – a measuring device that can be used for determining marine current flow speeds.
Assets	A physical item (or group of items) of infrastructure the either extract, convert or distribute energy e.g. wind farm, coal mine, electricity network.
AU	Ammonia Urea
Bar.g	Barometric gauge pressure – the pressure of a gas registered by a measurement gauge device, relative to the ambient pressure.
Bounded map	Land areas where activity is consider to be of low likelihood due to existing planning logistics e.g. Road in a National Park.
Bbl	"Esso" blue barrel – 42 US gallons, the international volumetric unit of oil.
Bpd	Barrels per day
BRANZ	Building Research Association of New Zealand - an independent consulting and information company providing resources for the building industry.
BTL	Biomass to liquids
CAPEX	Capital expenditure
CBM	Coal bed methane – Gas that can be dissociated for buried coal seams. Also known as coal seam gas (CSG).
CSS	Carbon Storage and Sequestration (or Sequestration) – The process of capturing greenhouse gas emissions can storing them for several hundreds of years
CCT	Carbon Capture and Trade
CGH_2	Compressed Gaseous Hydrogen
CHP	Combined Heat and Power. Electricity (power) production alone generates a lot of waste heat and is therefore doesn't recover maximum value from fuel. Heat generation achieves a fuel to energy output ratio, but doesn't produce high value electricity. A CHP operation combines the advantages of both.
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CO_{2EQV}	A common measure for greenhouse gas warming potential. This unit aggregates the emissions from CO2, CH4, SF6, N2Ox, HCF & PCF to Carbon Dioxide Equivalent.
CPI	Consumer Price Index
CTL	Coal to liquids
DME	Di-methyl Ether
DoC	Department of Conservation
DSM	Demand Side Management
E^3	A database used to assess Energy use, Economics and Emissions for processes
EDF	Energy Data File – Annual summary of New Zealand's energy demand. Maintained by MED.
EECA	Energy Efficiency and Conservation Authority
EERA	Energy Efficiency Resource Assessment
EEUD	Energy End-Use Database – Maintained by EECA
EEZ	Exclusive Economic Zone
EPRI	Electric Power Research Institute
EROEI	Energy Return on Energy Invested

EROFEI	Energy Return on Fossil Energy Invested
EtOH	Ethanol
F-T	Fischer-Tropsch process. A technology developed in Germany (1920s) which uses catalytic reactions to synthesise complex hydrocarbons from synthesis gas (carbon monoxide and hydrogen).
FC	Fuel Cell
FCV	Fuel Cell Vehicle
Firm capacity	A baseline (minimum) generation capacity that can be maintained on an inter-annual basis (e.g. dry year capacity of hydro power station).
FPSO	Floating Production, Storage and Offloading – a ship-based facility that accompanies offshore oil & gas drilling platform operations.
FRST	Foundation for Research, Science & Technology
FTE	Full-Time Equivalent – the equivalent number of people employed in full-time positions within an industrial sector.
GBS	Gravity-Base Structure – a heavy-duty, offshore, oil storage facility that is used to assist in offshore oil drilling operations.
GDP	Gross Domestic Product
GHG	Greenhouse Gas – Emissions that add to radiative warming of earth eg. CO_2, CH_4, SF6, PFC, HFC.
GIS	Geographical Information System
GJ	Giga-Joule = 1,000,000,000 Joules = 10^9 Joules of energy
GTL	Gas to liquids
GWP	GHG warming potential
HRAP	High Rate Algal Pond – a type of waste-water treatment pond
HEEP	Heat Energy Efficiency Program
HERA	Heavy Engineering Research Association
ICDP	International Continental Drilling Programme – towards the study of the Earth's crust, natural mineral resources and interactions with surface ecological systems.
ICE	Internal Combustion Engine
ICEV	Internal Combustion Engine Vehicle
IGCC	Integrated Gasification Combined Cycle
In-gate	All off-road transportation i.e. agriculture, forestry, mining, recreational and off-road vehicles.
IPCC	International Panel on Climate Change
Kt	kilo-tonne – equivalent to a million kilograms or a Giga-gram.
L/100 km	Litres per 100 km – a measure of fuel consumption used for road transport vehicles
lde	Litre of Diesel equivalent – a unit of measure for comparing the energy content of alternative fuels with that of a litre of conventional Diesel fuel.
LEAP	Energy pathway visualisation software – Long-range Energy Alternatives Planning.
LEAP framework	The database, output files and visualisation tools that are associated with running LEAP.
lge	Litre of gasoline equivalent – a unit of measure for comparing the energy content of alternative fuels with that of a litre of conventional gasoline ("petrol") fuel.
LHV	Lower Heating Value - the amount of heat produced by combustion of a unit quantity of a fuel, subtracting the latent heat of vaporization of the water vapour formed by the combustion.
LNG	Liquefied Natural Gas (mainly methane @ -160˚C)
LPG	Liquefied Petroleum Gas (mainly propane and butane)

mcfd	thousands of cubic foot per day
MED	Ministry of Economic Development
MEDF	Marine Energy Deployment Fund – administered by the EECA
MeOH	Methanol
MEPS	Minimum Energy Performance Standard
MJ	Mega-Joule = 1,000,000 Joules = 10^6 Joules of energy
mbbls	Thousand barrels – non-SI unit of volumetric measurement of oil
mmbbls	Million barrels – non-SI unit of volumetric measurement of oil (1mmbbl of crude oil contains approximately 6 PJ of energy)
MOT	Ministry of Transport
mmscf	millions of standard cubic feet
MT	Magneto-Tellurics – a technique used for mapping sub-surface rock features, relating to their natural, electrical conductivity.
Mt-km/$kt_{equivalent}$	Mega-tonne-kilometre travelled per kilo-tonne(equivalent) of various industrial stock moved.
MTG	Methanol-to-Gasoline plant
MW	Mega-Watt = million Watts – measurement of power output
NA & AN	Nitric Acid and Ammonium nitrate
NGL	Natural Gas Liquids
NZ	New Zealand / Aeotearoa
NZBCSD	New Zealand Business Council for Sustainable development
NZES	New Zealand Energy Strategy
NZEECS	New Zealand Energy Efficiency and Conservation Strategy
O & G	Oil and Gas
OPEX	Operational Expenditure
ORC	Organic Rankine Cycle
OWC	Oscillating Water Column – a form of wave energy conversion technology for marine applications.
Peak Oil	Defined as the maximum production (bpd) of a field, a province, or the world
Phase	The stage of development of an asset – eg. Research, Construction, Operating.
PHEV	Plug-in Hybrid Electric Vehicle
PJ	Peta-Joule = 10^{15} Joules = thousand, million, million Joules – measurement of energy.
PKT	Passenger Kilometres Travelled – used in the quantification of personal transportation
Risk score	An indication of the likelihood that a phase of asset development will fail (0 – Minimal to no risk; 5 – Extreme to almost total risk). When risk probabilities are applied to applied to Policy, research & financing costs an implementation risk ($000s) is calculated. When risk probabilities are applied to applied to operating capacity, an operational risk (MW) is calculated.
RMA	Resources Management Act
RON	Research Octane Number – a measure of the quality of a fuel, commonly seen at transport fuel filling stations to indicate the relative octane rating of petrol.
PWD	Public Works Directive
PV	Photo-Voltaic – relating to the conversion of solar energy, carried by photons, directly into electrical energy (via photo-voltaic cells that are built into panels or arrays).
RVP	Reid Vapour Pressure (The propensity of “light ends” to evaporate from crude oil).

SHW	Solar Hot Water
SI	le Systeme International d'unites – the international system for defining common units of measurement.
SMR	Steam Methane Reformation
SRF	Short Rotation Forest
StatsNZ	Statistics New Zealand
SUV	Sports-Utility Vehicle
Sweet gas	Well gas with low sulphur content (<4ppm H2S), as distinct from sour or "dirty"
TJ	Tera-Joule = 10^{12} Joules of energy
TE	Thermo-Electric – relating to the conversion of thermal radiation directly into electricity (via thermo-electric cells that are built into panels and arrays).
t-km	Tonne-kilomteres - used in the quantification of goods transportation
Tm^3	Tera-cubic metres – used as an SI alternative to "trillions of cubic feet" for measurement of natural gas reserves
tph	Tonnes per hour
TW	Tera-Watt = million-million Watts – measurement of large power output
US	United States of America
USDoE	United States Department of Energy
VFM	Vehicle Fleet Model – developed by the Ministry of Transport
VKT	Vehicle Kilometres Travelled – Generally associated wth passenger transportation.
WGIP	Wind Generation Investigation Project – set up by the Electricity Commission
WEC	Wave Energy Converters
WSP	Waste Stabilisation Pond – for waste-waster treatment

Appendices

APPENDIX A: SCHEMATIC OF NATIONAL OIL AND GAS ASSETS