Gas Supply and Demand Scenarios 2012 - 2027

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concept

Concept Consulting Group Limited
Level 6, Featherston House
119-123 Featherston St
PO Box 10-045, Wellington, NZ
www.concept.co.nz

Concept Consulting Group

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Preparation of this report

This report was prepared by Simon Coates, David Hunt and David Weaver.

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This report considers possible futures for gas in New Zealand, and identifies the key drivers and issues which are likely to affect how the supply and demand for gas is likely to develop over the next 15 years.

Gas supply

- New Zealand's gas supply position is stronger than it has been for many years driven by the highest level of exploration effort seen for a long time, driven by high oil prices.
  - Although exploration effort is predominantly focussed on oil, the fact that gas and oil are typically found together means that high oil exploration effort translates into increased likelihood of new gas being found.
- NZ has transitioned from the Maui-era which had a high dependence on a single declining offshore field. It now draws supply from an increasingly diverse range of onshore and offshore fields
- New Zealand's future gas outlook has also strengthened markedly
  - There are now sufficient reserves to last through to the mid-2020s based on current rates of use. This position is comparable with North America and Western Europe.
  - The petrochemical and power generation sectors play a valuable role in varying their consumption to match the prevailing supply position to help maintain the reserves / production ratio at relatively stable levels.
- This means the physical availability of gas to consumers is likely to be assured for the foreseeable future. To the extent uncertainty exists, it revolves around the *price* of gas. This report considers three illustrative scenarios for wholesale prices[1]:
  - Low price scenario ($4.5/GJ) – if exploration successes lead to an even stronger supply position (although not so large as to make it economic to export gas as LNG, at which point NZ gas prices would rise to the level of international LNG prices)
  - Medium price scenario ($7/GJ) – continuing adequate gas supply as has occurred since mid-2000's
  - High price scenario ($12/GJ) – where NZ prices are linked to international gas prices through development of an LNG import trade (in the case of v. limited exploration success) or export trade (in the case of a massive gas reserves being found – as is occurring in Queensland)
- As shown in Figure 1 below, current NZ gas market conditions appear to be somewhere between the medium price and low price scenarios – with wholesale gas prices having significantly eased from the peak levels (in real terms) seen in the mid-2000s
- This contrasts with Australia which appears to be moving from a relatively low gas-price position, to one that could be significantly higher than is expected for New Zealand, driven by the internationalisation of the Australian gas price through development of LNG export capabilities.

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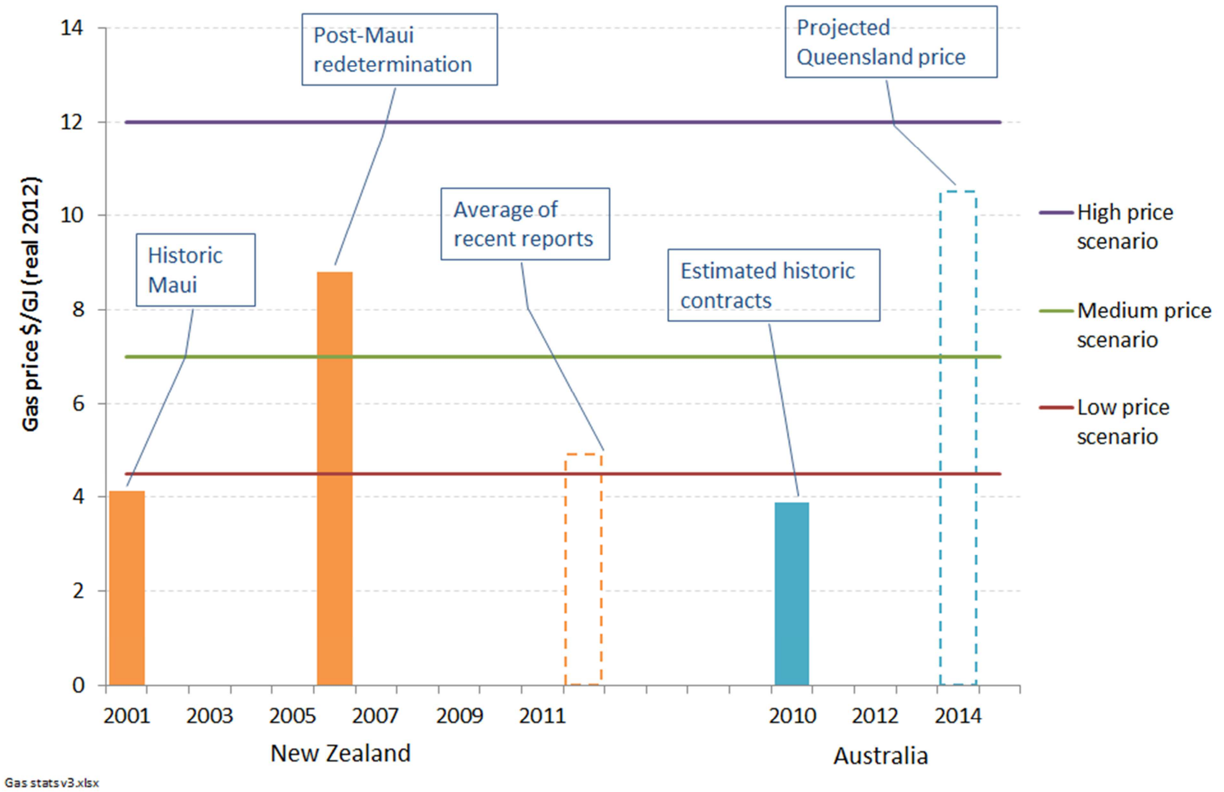
1 These are expressed in $/GJ at a transmission system receipt point in Taranaki, and therefore exclude any costs for transmission, swing, taxes etc.

Figure 1: Historic and projected wholesale gas prices in New Zealand and Eastern Australia



Source: Concept analysis based on data from company reports and disclosures, AEMO

In recent years New Zealand has moved into a position of greater gas availability, and this is being reflected in softer wholesale gas prices relative to earlier levels (albeit above the 'low gas price' scenario). Current indications are that these conditions are likely to continue for some years. Looking further ahead, it is more difficult to predict gas prices, and they could firm or soften depending on the rate of reserves additions versus usage. That said, any sudden major step-up in wholesale gas prices inside a five year period appears relatively unlikely, as the required preconditions would take some years to develop and would be unlikely to occur without warning.

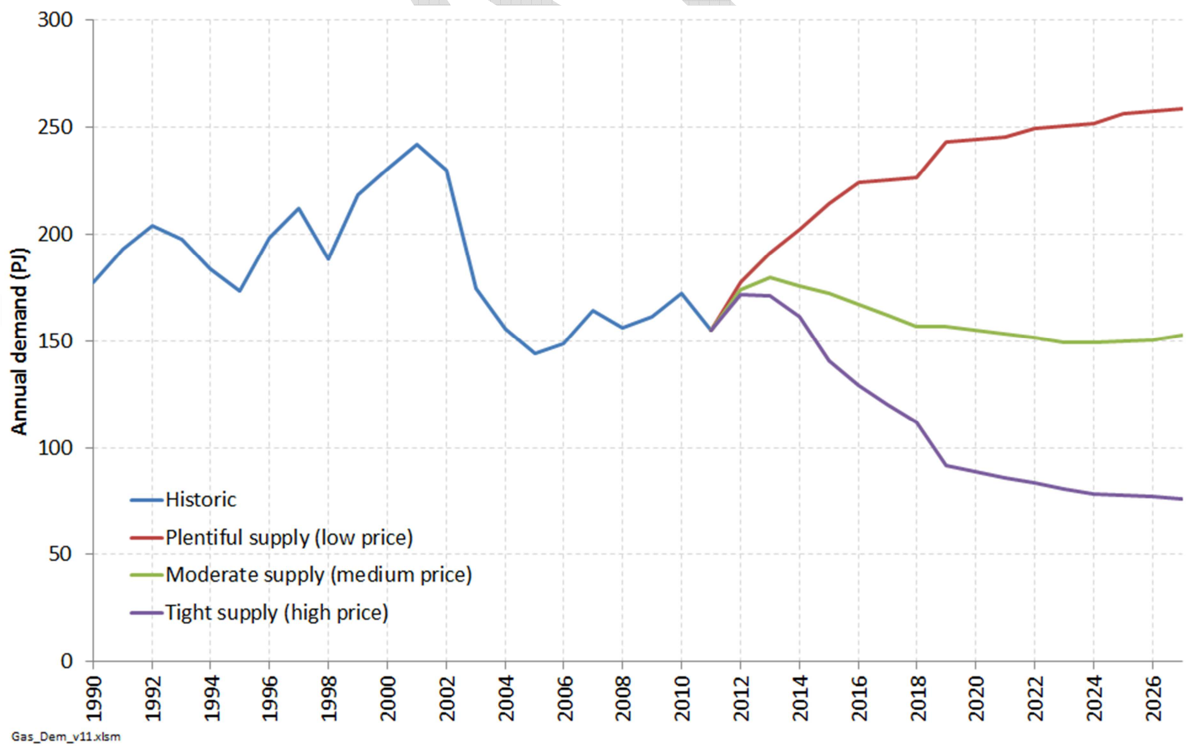
Gas demand

- Long-term gas demand in New Zealand is likely to vary significantly between the different price scenarios, ranging from 250 PJ/year in the low price scenario down to 75 PJ/year in the high price scenario
- As between the scenarios, the sectors where the main change in gas demand occur are petrochemical manufacturing (especially methanol production) and power generation – as these sectors are the most sensitive to changes in wholesale gas prices.
- The rolling off of existing gas contracts for power generators, coupled with the development of gas supply flexibility capability such as the Ahurora gas storage facility and gas reinjection at Pohokura, is likely to mean that gas-fired generators will respond even more flexibly to changing gas prices. This increased gas supply flexibility will likely also mean that gas-fired power generation will on

average consume less gas than historically, because of their better ability to avoid operation during low electricity price periods.

- Gas demand for other industrial, commercial and residential users is relatively steady across the scenarios. This is because:
  - even in a high gas price world, gas has a relatively strong position relative to alternative fuels due to the significantly lower process heat boiler capital and non-fuel operating costs compared with coal and biomass alternatives, such that any switching away from gas is likely to be relatively modest; and
  - in a low gas price world, the growth in gas demand will be limited by the growth in demand for energy services which will be closely linked to the growth in GDP. This is likely to be of the order of a few percent a year.
- This much greater demand variability of the petrochemical and power generation sectors illustrates the valuable 'shock-absorber' role fulfilled by such sectors:
  - they provide ready markets for gas when it is plentiful (thereby significantly lowering the cost of producing oil, making New Zealand a more attractive place to invest to produce hydrocarbons); but
  - they scale-back demand if gas reserves become scarce (thereby extending the life of reserves for the majority of gas users).

Figure 2: Projections of total New Zealand gas demand



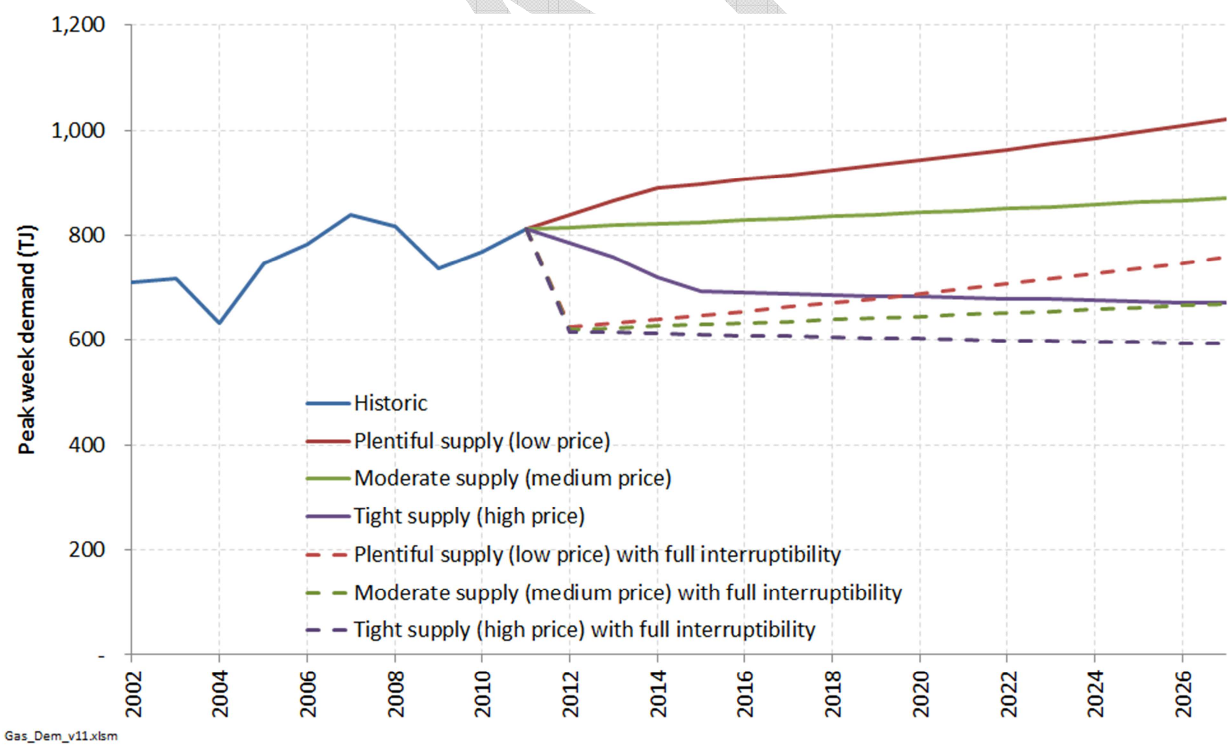
Source: Concept estimates

As indicated above, New Zealand currently appears to be on a trajectory which is close to the Low price scenario, resulting in increasing demand – particularly from the petrochemical and (to a much lesser extent) power generation sectors.

Pipeline investment issues

- The existing pipeline system is expected to have sufficient capacity to accommodate the projected scenarios with higher demand.[2]
- The only significant exception is Vector's northern pipeline system (from central Waikato northwards). This system has already reached its capacity limit during peak weeks, and it appears that some potential new gas demand is being suppressed in this region through an inability to secure pipeline capacity.
- However, some gas users (e.g. power generators) appear to have relatively low cost options to reduce their usage during peak demand periods.
- The scale of this potential is such that, if it can be harnessed, the need for costly new investment may be deferred for many years – as shown in the chart below – and it would allow currently suppressed potential new demand to connect to network.
- To harness such potential would require changes to pipeline pricing and access regimes, in order to send better signals to pipeline users of the cost of pipeline capacity at times of peak demand. The means by which such changes could be effected is beyond the scope of this study. However, this study does appear to indicate that relief of pipeline congestion in the North system through altered pricing and access arrangements would be a worthwhile achievement.

Figure 3: Projections of peak week gas demand on the Vector North gas transmission system



Source: Concept estimates

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2 Some investment would likely still be required in some specific areas – but not to the extent of requiring major new pipelines. New pipeline investment might also be required to connect new gas finds in locations such as the East Cape to the national transmission system.

- It is unlikely that new gas-fired generation would be developed in a location requiring connection to the Vector transmission system, but would instead be developed in Taranaki or a location along the Maui pipeline in the Waikato. This is because:
  - There are greatly reduced electrical benefits from locating a power station in Auckland or Northland due to major electricity transmission upgrades.
  - Conversely, a gas-fired power station in Auckland / Northland would likely incur significant gas pipeline upgrade costs.

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1 Introduction

This report considers possible futures for gas in New Zealand, and identifies the key drivers and issues which are likely to affect how the supply and demand for gas is likely to develop over the next 15 years.

The report is structured in three main parts:

The section titled "*Gas supply and price scenarios*" considers factors driving New Zealand's likely supply position. As well as comparing New Zealand's supply position with overseas gas markets, it examines the prospects for future gas supply from four potential sources:

- Additional Taranaki-based conventional gas
- Non-Taranaki conventional gas
- Unconventional gas
- Gas importation

The section titled "*Gas demand scenarios*" considers the drivers behind possible changes in demand for gas in three main sectors:

- Petrochemicals (principally methanol and urea production)
- Power generation; and
- Industrial, commercial and residential gas use for space, water and process heat

The section titled "*Peak demand scenarios and pipeline investment*" considers the drivers behind peak gas demand on the Vector transmission system. It develops statistical approaches to forecast weather-corrected peak demand, and considers the potential for increased use of interruptible gas contracts to alter the level of peak demand on the network.

This section particularly focuses on the Vector North System which in 2011 experienced peak demand at the limit of its pipeline capacity. It develops projections to assist consideration of the likely need for investment to increase the pipeline's capacity.

In undertaking this study the project team spoke with a large number of representatives from companies and organisations across the gas supply chain, including: upstream exploration & production, gas transmission and distribution, gas retailers and various other gas consumer sectors including power generation, petrochemicals, dairy, forestry and paper, steel, oil refining, and food processing.

Concept would like to thank all these representatives for their time, and the insights which they shared with the project team.

2 Gas supply and price scenarios

Chapter summary

- New Zealand's gas supply position is stronger than it has been for many years driven by the highest level of exploration effort seen for a long time, driven by high oil prices.
  - Although exploration effort is predominantly focussed on oil, the fact that gas and oil are typically found together means that high oil exploration effort translates into increased likelihood of new gas being found.
- NZ has transitioned from the Maui-era which had a high dependence on a single declining offshore field. It now draws supply from an increasingly diverse range of onshore and offshore fields
- New Zealand's future gas outlook has also strengthened markedly
  - There are now sufficient reserves to last through to the mid-2020s based on current rates of use. This position is comparable with North America and Western Europe.
  - The petrochemical and power generation sectors play a valuable role in varying their consumption to match the prevailing supply position to help maintain the reserves / production ratio at relatively stable levels.
- This means the physical availability of gas to consumers is likely to be assured for the foreseeable future. To the extent uncertainty exists, it revolves around the *price* of gas. This report considers three illustrative scenarios for wholesale prices[3]:
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- Current NZ gas market conditions appear to be somewhere between the medium price and low price scenarios – with wholesale gas prices having significantly eased from the peak levels (in real terms) seen in the mid-2000s
- This contrasts with Australia which appears to be moving from a relatively low gas-price position, to one that could be significantly higher than is expected for New Zealand, driven by the internationalisation of the Australian gas price through development of LNG export capabilities.

2.1 Historic gas supply

Natural gas has been produced in New Zealand for more than forty years. As shown in Figure 4, there have been distinct supply phases over this period, reflecting different states of the industry. The 1970s were characterised by relatively low levels of gas supply and demand (less than 50 PJ/year), as both gas

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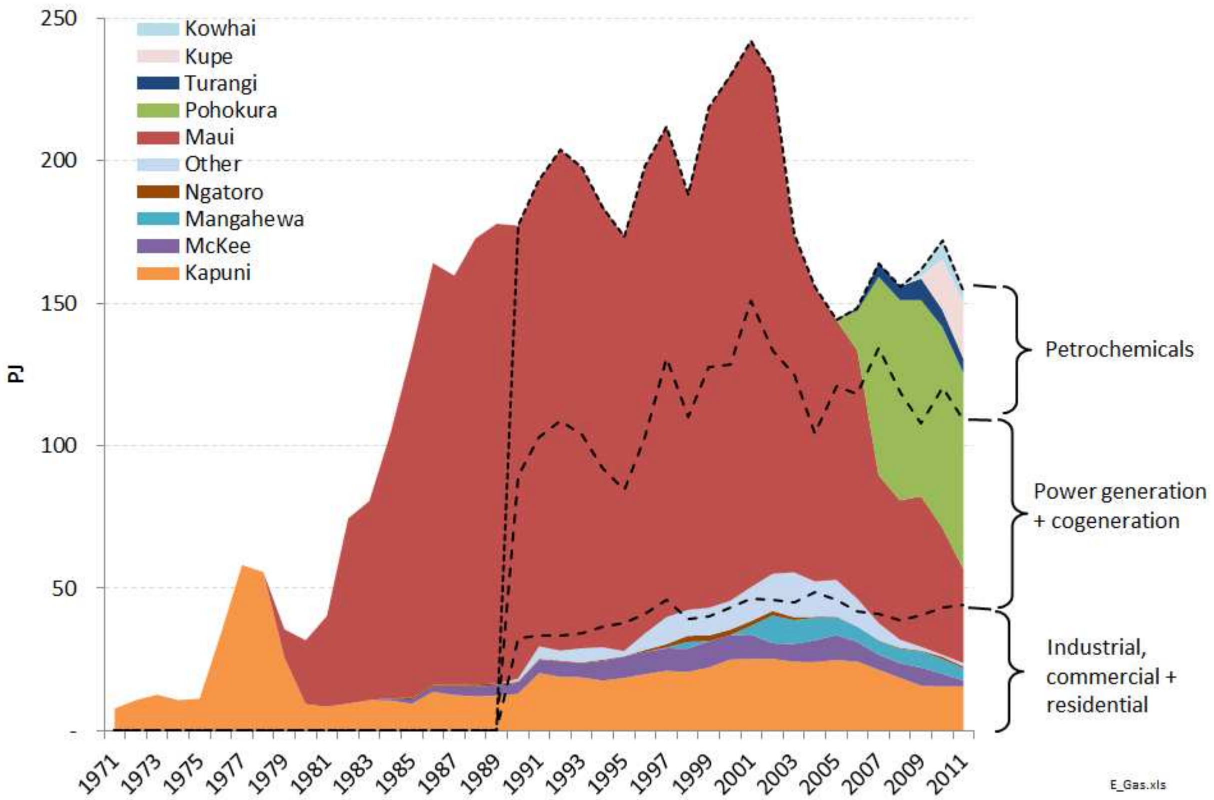
3 These are expressed in $/GJ at a transmission system receipt point in Taranaki, and therefore exclude any costs for transmission, swing, taxes etc.

production and gas using industries were established. Gas production then expanded rapidly in the 1980s as the Maui field came on stream and usage increased for petrochemical production and power generation. For most of the next two decades gas production (and demand) ranged between 200-250 PJ/year.

Figure 4: Natural gas production 1971 - 2011

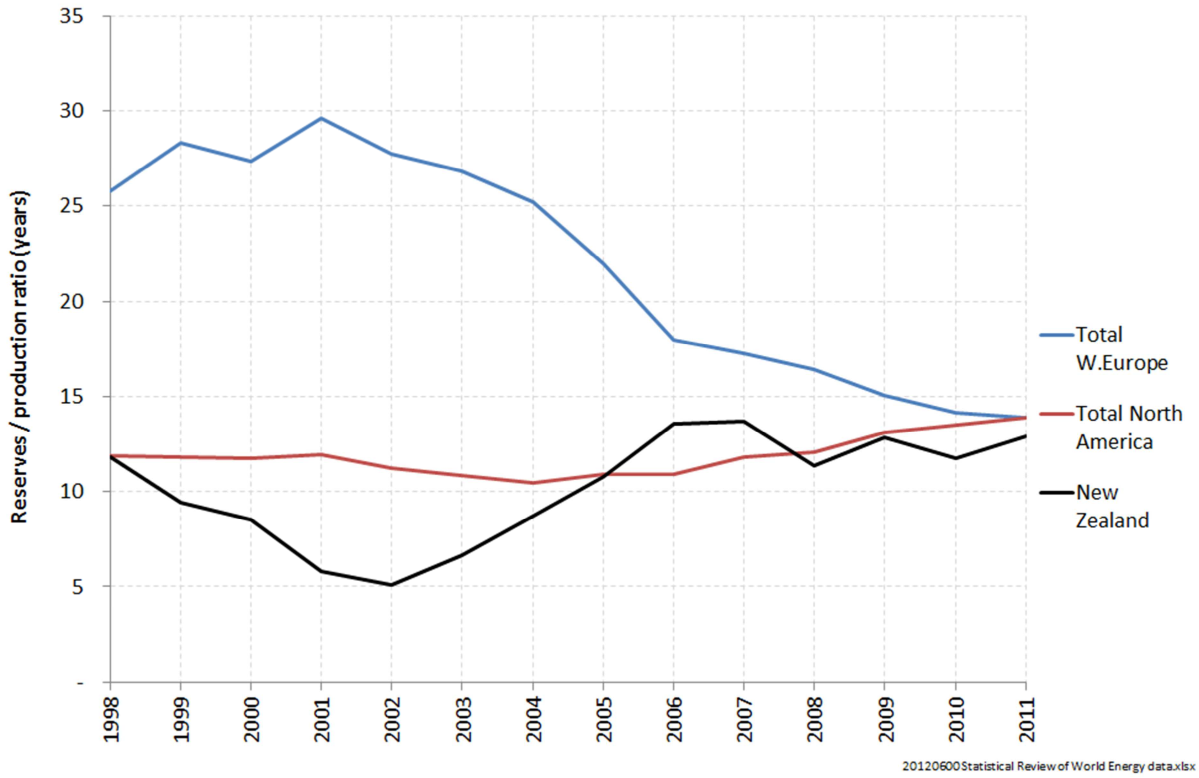


Source: Ministry of Business, Innovation and Employment, Energy Data File, July 2012. Excludes production from the offshore Tui and Maari fields as they are not connected to the gas transmission system. Usage data by sector not shown for period prior to 1990.

In 2003, the remaining economic reserves in the Maui field were revised downwards. This led to a sharp rise in gas prices and significant reductions in usage by some types of gas users – especially petrochemical production and power generation. More recently, and as set out in more detail in this report, new fields have been brought into production and reserves added within existing fields, plus there has been an upsurge in exploration activity. This has resulted in a softening of gas prices and a recovery in gas demand (especially for petrochemical production).

As discussed later in this report, this tendency for some categories of demand (especially petrochemical production and power generation) to respond relatively swiftly to changes in reserves has important wider implications. In particular, it means that reserves to production ratios (i.e. the number of years that gas 'inventory' will last at prevailing production rates) tends to converge back to around 10-15 years, despite significant changes in remaining reserves. This is illustrated in Figure 5.

Figure 5: Reserves (P50) to production ratio and remaining reserves



Source: BP Statistical Review, Ministry of Business, Innovation and Employment, Energy Data Files. Excludes production from the offshore Tui and Maari fields as they are not connected to the gas transmission system.

Furthermore, this tendency for reserves to production ratios to be relatively stable is not uncommon internationally as shown by Figure 6. In essence, countries or regions where large gas reserves are found tend to develop new gas-using industries, particularly *export* of gas via pipelines or as liquefied natural gas or methanol. This is shown by the steeply falling ratio for Norway and Mexico.

Conversely, if gas reserves decline in a country or region, gas export will also start to decline.

Thus, only where domestic supply far outstrips domestic demand will significant gas export be undertaken. Otherwise, higher-value domestic uses for gas (as a fuel for space, water or process heat) will tend to out-compete the typically lower-value export options.

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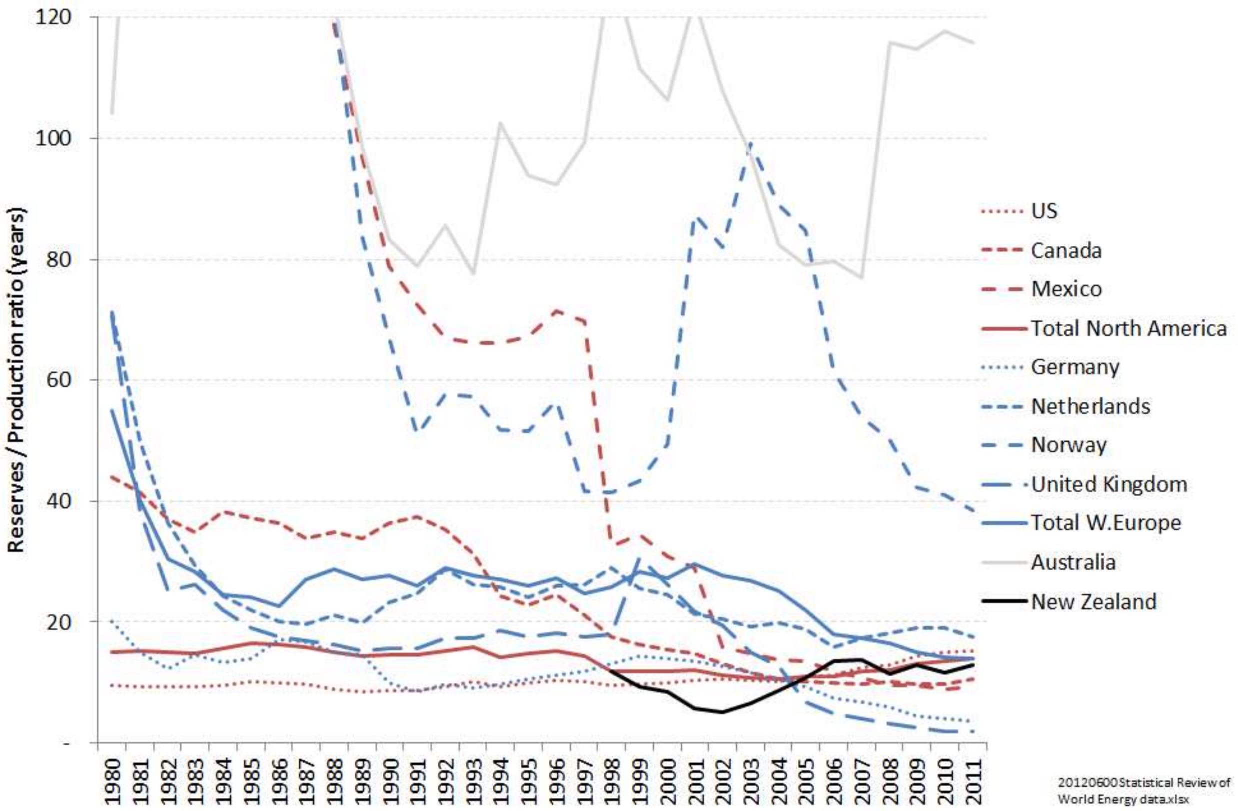
Figure 6: International comparison of reserves to production ratios



Source: Concept analysis using BP Statistical Review data

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Looking ahead, the forces which tend to stabilise the reserves to production ratio are expected to continue to apply in New Zealand. As a result, a large increase in reserves is likely to stimulate higher gas demand over time (and possibly even new gas using industries). Conversely, falling reserves would be expected to lead to reduced demand. Such demand changes would not be uniform across gas users.

Generally speaking, the petrochemical and power generation sectors are expected to be in the 'frontline', experiencing the greatest impact (positively or negatively) from changes in reserves. The reasons for this flexibility are set out in sections 3.2 and 3.3. As a result of this ability for the petrochemical and power generation sectors to significantly alter their demand in response to changing reserve positions, the availability of gas for residential, commercial and industrial users is assured in all but the most extreme gas exploration 'drought'.

Furthermore, in that very unlikely situation, New Zealand would have the option of supplementing supply from gas importation, particularly as rapidly increasing gas exports from Queensland will make Australia one of the world's largest gas exporters within a few years.

These factors highlight that the more relevant issue in the supply context is the price at which gas is available. This issue is explored in more detail in the following sections, beginning with a discussion about the potential sources of supply.

2.2 Potential sources of gas supply in New Zealand

Over the 15 year time horizon covered by this report, New Zealand may draw on gas supply from a variety of potential sources. These include:

- conventional gas reserves in the Taranaki basin;
- conventional gas reserves outside the Taranaki basin;
- unconventional gas sources; and
- gas importation.

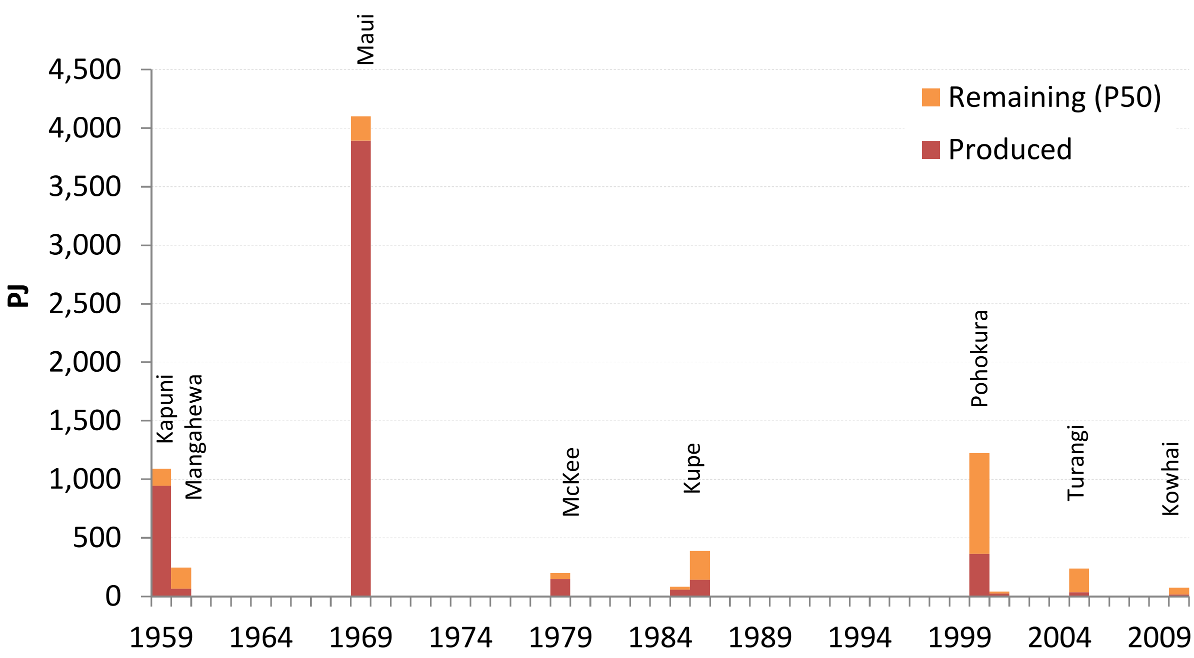
Each of these potential sources of gas is discussed in the next sections.

2.3 Conventional gas reserves – Taranaki basin

All of New Zealand's existing gas production comes from fields within the Taranaki basin. Indeed, this region has a long history of supply, with the first well drilled in 1865 and petroleum products having been continuously produced from the basin since about 1900.

Larger scale operations began with the discovery of the onshore gas-condensate field at Kapuni in 1959, followed by the much larger Maui offshore gas-condensate field in 1969. Since that time, a number of other gas discoveries have been made in Taranaki as shown in Figure 7.

Figure 7: Discovery dates for gas and oil fields in Taranaki basin

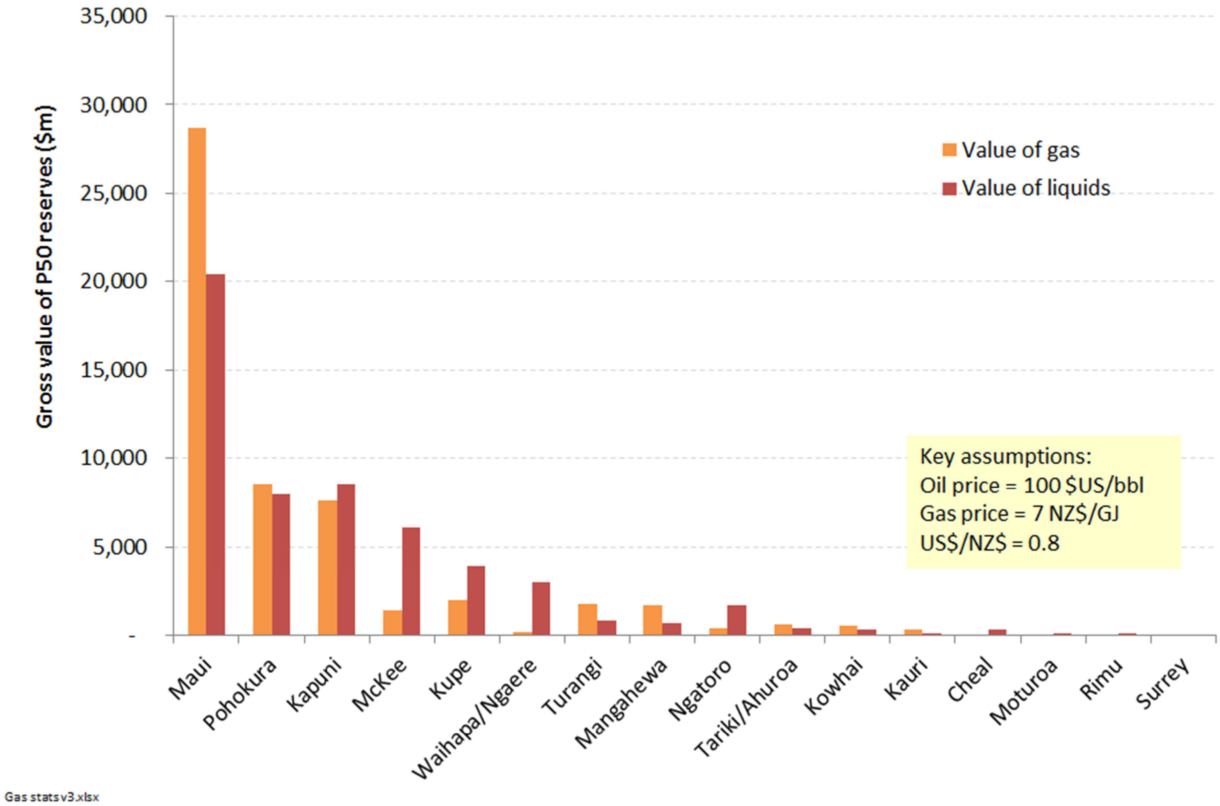


Source: Compiled from NZ Petroleum and Minerals data, company reports. Data shows year of spudding well for initial discovery. Data shows remaining reported gas reserves as at 1 January 2012

As shown by Figure 7, discoveries in Taranaki have been lumpy in nature – reflecting the relatively small number of exploration wells drilled in most years, and the inherent uncertainties associated with gas and oil exploration. Indeed, the discovery of the large Maui field meant that the domestic market for gas was saturated for many years, and inhibited gas exploration effort.

All of the discoveries brought into production to date have been oil fields or gas condensate fields. Indeed, the presence of liquids has a major influence on the commercial viability of field development. This is illustrated in Figure 8 which shows the relative value of gas and liquids reserves for different fields.

Figure 8: Gross value of gas and oil reserves (ultimately recoverable P50 estimates)



Source: Compiled from NZ Petroleum and Minerals data.

The relatively high value of liquids compared to gas has two important implications:

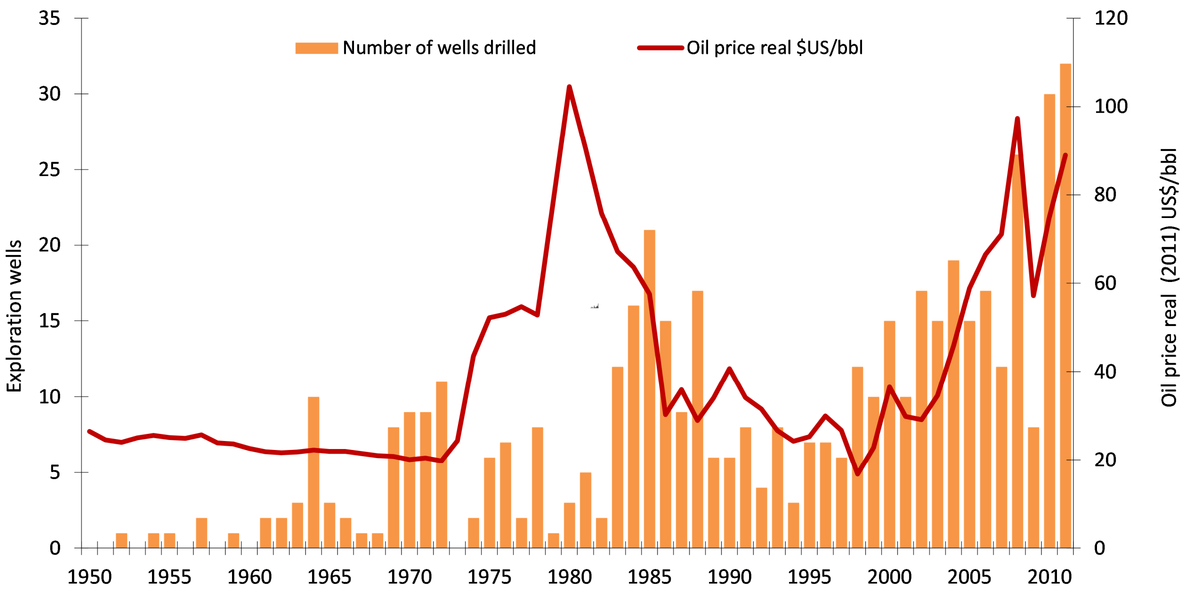
- It influences how quickly a field will be developed once it is discovered. For example, the McKee field was developed within a few years of discovery, whereas the drier Mangahewa field was many years before it was brought into production; and

- exploration effort (and therefore likelihood of success) is influenced by prevailing oil prices.

The second factor is especially important when considering the gas supply outlook. Over the last decade there has been a marked upward shift in real oil prices as shown in Figure 9, and major forecasters expect this movement to be sustained reflecting rising demand in emerging economies and/or increasing costs to develop new reserves[4].

As shown in Figure 9, the level of exploration effort has been correlated with real oil prices. The marked upward shift in oil prices (and general expectation that this will be maintained relative to historic levels) suggest that exploration activity is likely to remain at increased levels, relative to the longer term average seen in New Zealand. This in turn raises the likelihood of gas discoveries (given that gas is often associated with oil finds). Furthermore, the higher oil prices are also making it more attractive for parties to extend the life of existing fields.

Figure 9: Drilling activity and oil prices



Source: Compiled from NZ Petroleum and Minerals data. [check data]

The broad increase in activity in Taranaki is reflected in developments such as:

- In July 2012 Shell Todd Oil Services (STOS) announced plans for a two year programme of drilling from the Maui A platform to target bypassed gas. The reported value of the drilling contract was USD $45 million. STOS also began a new phase of drilling at Maui B in late 2011, which involves up to seven new wells being drilled. Earlier efforts to extend Maui's life are already showing some benefits, with P50 reserves estimated of 207.9 PJ as at 1 January 2012, more than doubling the estimated remaining reserves, as compared to a year earlier;

- In early 2012 Todd Energy announced a programme to expand gas production from the Mangahewa/McKee fields by up to 25 PJ/year. The programme involves investment of around $750m over ten years in new wells and expansion of the McKee production facility. The gas from this campaign has been purchased by Methanex;

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4 For example, see the International Energy Agency's *World Energy Outlook*.

- A significant life extension programme for the Kapuni field is due to commence in mid-2012. This involves working over an existing well, and drilling two new wells. The programme is also likely to include hydraulic fracturing to enhance flow rates and reserves recovery;

- In mid-2012, reserves in the Kupe field were reassessed in light of two and a half years of production data. This led to an 18% increase in estimated remaining gas reserves, bringing the total to 276 PJ;

- Since 2010 TAG Oil has made a number of oil and gas discoveries in onshore Taranaki in the Sidewinder permit area. In November 2011, TAG Oil completed a production station capable of processing up to 11.5 PJ of gas/year from this field. In March 2012, TAG Oil announced plans for a $80 million[5] capital expenditure programme at its Cheal and Sidewinder projects covering a mix of further exploration and development drilling, as well as investment in increased production facilities;

- New Zealand Energy Corp (NZEC) began shipping gas from its Copper Moki discovery in southern Taranaki in mid-2012. NZEC has also entered into an agreement with Origin Energy to purchase the Waihapa production station, and four nearby exploration permits, for $51 million[6].

In summary, absent a sustained decline in real oil prices[7] or significant adverse changes in the policy environment, there are strong grounds to expect gas production in Taranaki to remain at current or higher levels over the 15 year projection period.

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5 The disclosed figure was Canadian $66 million.

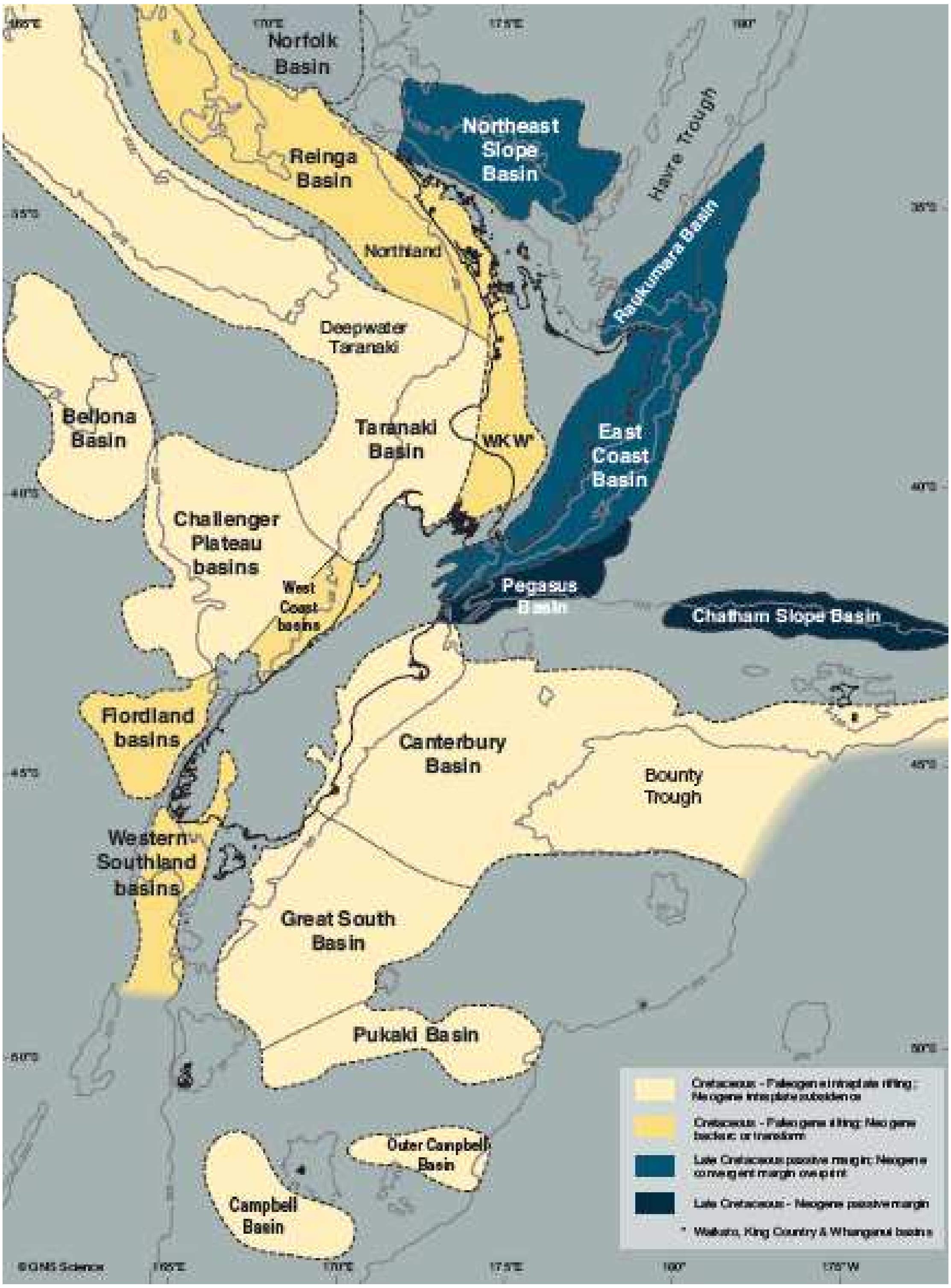
6 The disclosed figure was Canadian $42 million.

7 Noting that while most forecasters expect higher oil prices to generally be maintained, there are also scenarios where oil prices fall due to improvements in technology and/or changes in demand or geopolitical factors.

2.4 Conventional gas reserves - ex-Taranaki basin

While all of New Zealand's existing gas production comes from fields in the Taranaki basin, there are 17 other identified basins within the country's territorial jurisdiction as shown in Figure 10.

Figure 10: Petroleum basins in New Zealand



Source: NZ Petroleum and Minerals

The area covered by these basins is large. Indeed, New Zealand has sovereign rights to over 5.7 million square kilometres of land and seabed – equivalent in size to the European Union, the North Sea, and a quarter of the Mediterranean sea combined[8].

A large proportion of this territory has not been explored other than by reconnaissance survey. However, the available data suggest that basins which may host oil and gas cover about 20% of New Zealand's territory. Where limited exploration has occurred, it has confirmed the presence of hydrocarbons in a number of cases (albeit at levels judged uneconomic to develop) as shown in Table 1.

Table 1: Oil or gas shows and finds outside Taranaki

Well	Region	Date	Comment on test results
Kawau-1A	Great South Basin	1977	7 TJ/day gas, and estimated reserves of ~500 PJ
Galleon-1	Offshore Canterbury	1985	10 TJ/day of gas and 2,300 bbl/d of condensate
Kora-1	Offshore Taranaki	1988	1,168 bopd and estimated reserves of 1 mmbbl
Titihaoa-1	Offshore Wairarapa	1994	Gas show
Kauhauroa-1	Onshore East Cape	1998	Up to 12TJ/day of methane
Karewa	Offshore Raglan	2003	60-160 PJ of gas (97% methane)

Source: NZ Petroleum and Minerals

More recently, the government has stepped up efforts to encourage exploration in areas outside Taranaki[9]. In 2008 and 2009 it funded seismic acquisition programmes over almost 6,000 km^2 of seabed in the Reinga and Pegasus basins, and the Bounty trough. It has also recently licensed parts of five frontier offshore basins, Great South, Canterbury, Raukumara, deep water Taranaki and Reinga to large international companies for exploration.

In mid-2012, the government made an additional 23 blocks available for exploration by qualified parties. A decision on the award of these blocks is due to in late 2012. The areas subject to existing exploration activity and those covered by the latest block offer are shown in Figure 11.

8 NZ Petroleum and Minerals

9 Including deep water Taranaki basin.

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Figure 11: Offshore exploration activity

Source: Compiled from NZ Petroleum and Minerals data, and company reports. Locations are approximate.

The combination of increased acquisition and provision of seismic data by government since the mid-2000s, improved deep-water drilling and production technology, and higher oil prices is expected to increase exploration effort outside the immediate Taranaki basin, and increases the likelihood of a major find.

This in turn raises the issue of how any major gas discovery outside of Taranaki could affect the domestic gas market during the projection period. To assess this issue, it is necessary to consider the size and proximity of any find relative to the existing sources of gas demand.

The first key point to note is that most basins are remote from demand centres and existing pipeline infrastructure. Even the 'closer' basins (East Coast, Raukumara) are on the periphery of the existing gas transmission system. In these areas the gas pipeline network has much lower transmission capacity than the main Taranaki – Auckland corridor. The only exception is the deep water Taranaki basin, which is relatively close to existing major gas transmission capacity (albeit requiring new submarine pipeline for interconnection).

This means that significant investment in extending or upgrading pipeline capacity would be required to connect any major new gas find outside the Taranaki basin into the New Zealand market. For example, construction costs for pipelines in the United States were reported as ranging between US$1.5-4.7 million per mile[10]. A find in one of the 'frontier' basins would need to be very sizeable to justify the required investment in new pipeline infrastructure and processing facilities.

Another factor to consider is whether the domestic market could absorb a large new gas find outside of Taranaki. For example, a sizeable gas find (say Pohokura or larger) is likely to require annual sales of at least 60 PJ/year to justify the necessary investment in gas processing and transmission infrastructure. This would be equivalent to around one third of existing total gas usage. If other sources (i.e. principally Taranaki fields) can meet prevailing demand, a new more distant gas source would be reliant on load growth for its sales. Domestic demand growth of this magnitude would need to come largely from increased petrochemical production, or use in power generation. In both cases, some investment/reinvestment would probably be required.

For these reasons, a more likely outcome (especially for a large and remote find) is for gas to be exported[11], probably as liquefied natural gas (LNG), but potentially alternatively as methanol. From a producer's perspective, this removes the dependence on the relatively small scale domestic market and also allows gas to be sold on a relatively flat production profile (see section 2.9 which discusses swing).

Historically, international gas finds have had to be of very large size and relatively close to shore (or onshore) to justify the investment in LNG production. However, floating LNG (FLNG) production facilities are now under construction and these are expected to alter the position for gas fields previously deemed to be uneconomic. For example, Shell is developing the Prelude FLNG facility 475 km offshore from Broome in Western Australia. This project will develop the Prelude and Concerto fields, which together have around 3,150 PJ of liquids-rich gas.[12]

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10 Oil and Gas Journal, Data Book 2008. These estimates are for 30 inch diameter pipelines (the Maui pipeline is a 30 inch line).

11 As discussed later, it is also possible that LNG might be consumed domestically.

12 The project is due to commence production in 2016-17. Once completed, the processing facility will be the largest floating structure ever built, at six times the size of the largest existing aircraft carrier. See www.shell.com/home/content/aboutshell/our_strategy/major_projects_2/prelude_flng/overview/ for more information.

In summary, there are signs of increasing exploration effort in basins outside the traditional Taranaki region, and a commercial-scale gas find in the 2012-2027 period is quite feasible. However, new gas transmission capacity would be required to bring such a find to the existing New Zealand market (i.e. the North Island), and the requirement could be very sizeable given the remote nature of some basins. There would also be some challenges in integrating a new find into the existing market assuming that supply from Taranaki remains adequate to meet demand.

For these reasons, there is a strong likelihood that a large scale new gas find would be converted to LNG, and destined primarily for the export market[13]. In this case, a large find might have little or no impact of gas supply and prices in the domestic market.

2.5 Unconventional gas

Internationally, there has been a recent and marked step up in unconventional gas production. This reflects a combination of higher gas and oil prices and technological advances, such as hydraulic fracturing ('fracking') and horizontal drilling.

Conventional and unconventional gas – terminology

Gas deposits are classified as conventional if they are contained in porous rock which allows gas to flow freely through the reservoir and into well boreholes.

Unconventional reserves are contained in rock of much lower permeability, making it harder to extract the gas. More complex methods are needed to extract unconventional gas, such as hydraulic fracturing to shatter the rock and promote gas flow. Examples of unconventional gas sources are:

- Shale gas – where gas is trapped in shale deposits, made up of thin layers of fine-grained sedimentary rock, typically found in river deltas, lake deposits or floodplains
- Coal seam gas (CSG) – where methane is stored in coal seams of low permeability (also known as coal bed methane)
- Gas from underground coal gasification (UCG) – where an underground combustion process is used to convert coal into methane, hydrogen, carbon monoxide (and other products), which are then extracted from wells drilled into the coal seam.

The development of unconventional gas resources is having a profound effect in some regions. For example, the development of shale gas resources in the last decade is transforming the United States from a net importer to a net exporter of gas. Indeed, the United States is reported to have overtaken Russia as the world's leading producer of dry natural gas in 2010[14].

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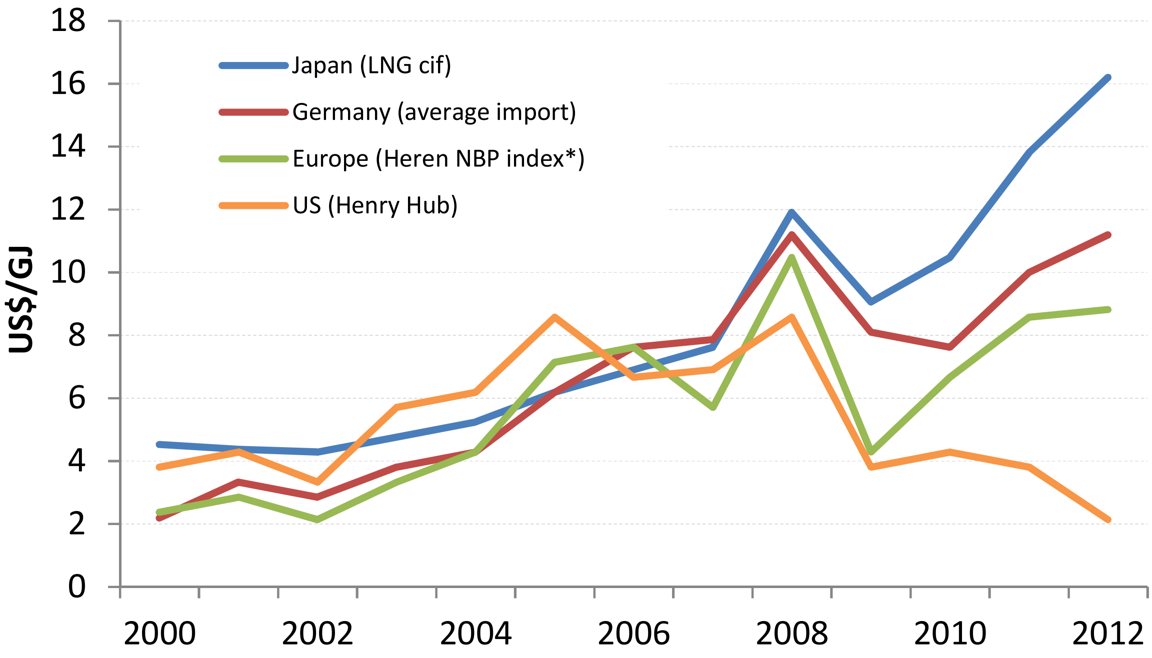
13 It is possible that some production might be 'exported' to the North Island. See section 2.6 for the discussion of LNG importation.

14 United Stated Energy Information Agency, see www.eia.gov/todayinenergy/detail.cfm?id=5370

The development of unconventional resources is having a major effect on gas prices in some markets. As shown in Figure 12, gas prices in the United States were typically higher than those in Europe and Japan. Since 2008, there has been a steep decline in United States gas prices, largely attributed to the 'shale gale', while gas prices in Europe and Japan has continued to trend upwards.

Figure 12: International gas prices



Source: The Economist

The gas market in Eastern Australia is also being markedly changed by the development of unconventional resources (in this case CSG). Production was almost non-existent five years ago, but has been rapidly increasing. CSG reserves now accounts for around 80% of 2P reserves[15] in the region. CSG reserves are being rapidly developed to underpin the establishment of an LNG export industry from Queensland. This in turn is putting upward pressure on domestic gas prices, as producers increasingly make trade-offs against an export price (i.e. LNG price less costs of liquefaction and transport).

The significance of unconventional gas resources was highlighted in a special report recently released by the International Energy Agency (IEA)[16]. The IEA notes that unconventional resources pose some specific environmental challenges, and that public concern about these issues may hinder the industry's growth. However, the IEA also notes that technologies and know-how exist to satisfactorily address these issues. It argues that producers and governments should proactively apply these techniques, to ensure the industry retains or earns its 'licence to operate'. The IEA forecasts that, provided the environmental issues are managed, unconventional resources could account for almost two-thirds of the growth in global gas supply over the period to 2035.

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15 Australian Energy Market Operator, Gas Statement of Opportunities, 2011.

16 *International Energy Agency*, Golden Rules for a Golden Age of Gas, World Energy Outlook Special Report on Unconventional Gas, July 2012

The changes in the unconventional gas industry occurring at the global level also have implications in this country. New Zealand is known to have unconventional gas sources, and there has been an increasing level of activity in this segment of the market in the last few years, covering shale resources, coal seam gas and underground regasification.

2.5.1 Shale resources

Around 50 wells have been drilled in the East Coast Basin since the 1970s focussing on conventional oil prospects. Many wells encountered oil or gas, but none yielded a commercial discovery suggesting that hydrocarbons were not trapped by a closure structure. Recent exploration has targeted a mix of conventional reservoirs targets, and unconventional opportunities in shale formations that are believed to be the source rocks for the basin's entire hydrocarbon system.

These shale formations are reported as being extensive and extremely thick in places[17], indicating the potential for a very large resource. For example, TAG Oil reports an estimated undiscovered resource potential (P50) of 12.65 billion barrels for unconventional OOIP[18] and 1.74 billion barrels for conventional OOIP for its permit areas alone. It also reports the potential for a recovery factor similar to that observed for the extensive Bakken shale resource in North Dakota (12%).

The East Coast shale formations have not been targeted in previous oil and natural gas drilling because they were regarded as being too impermeable. The recent improvements in unconventional oil and gas technology have stimulated stronger interest in the resource by some parties. On the other hand, some industry observers remain sceptical about the potential for commercialisation of East Coast shale resources, citing the extensive faults in the underlying structures, difficult terrain and relative distance to infrastructure.

One of the parties showing strong interest in the region is TAG Oil, which has secured exploration permits over 7,000 square kilometres of onshore land in the East Coast basin. In early 2011 TAG Oil drilled three shallow wells at Waitangi Hill near Gisborne. It reported the discovery of oil and gas at high pressure in all 3 wells[19]. TAG Oil has entered into farm-in arrangements with Apache Energy, which allows Apache to acquire interests in TAG Oil's East Coast permits, in exchange for underwriting a phased exploration campaign.

NZEC holds three onshore permits totalling 7,452 square kilometres. NZEC has recently drilled three stratigraphic wells, and is currently engaged in seismic acquisition and interpretation with the intention of moving to exploration in 2013.

In August 2011 Australian-based Tamboran Resources and Canadian firm Marauder Resources applied for onshore acreages in the Wairarapa/Hawkes Bay area.

2.5.2 Coal seam gas

CSG wells accounted for 16 of the 45 petroleum wells drilled in 2010. Drilling activity was concentrated in Taranaki and Waikato Basins, with work also carried out in Whanganui, West Coast and Southland

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17 Company disclosures from TAG Oil and New Zealand Energy Corporation.

18 Original Oil in Place. A recovery factor is applied to estimate the commercial production potential.

19 See www.tagoil.com/waitangi-hill.asp

Basins. In 2010 L&M Coal Seam Gas drilled eight wells across the Waikato, Whanganui and Southland Basins. During that year it upgraded the assessed reserves at Ohai in Southland by 58%, to 274 PJ (3P). In 2012 it announced plans to drill up to eight wells in the previously unexplored South Canterbury area. It also announced a coal seam appraisal programme near Dunedin, targeting gas for electricity generation.

Comet Ridge NZ Pty Ltd continued its drilling programme on the West Coast in 2010, and announced the certification of 244PJ of contingent resource near Greymouth. In 2011 it announced plans for a small scale trial of gas-fired generation, with the intention of increasing capacity as production levels increase.

Solid Energy New Zealand Limited (Solid Energy) has undertaken drilling activity in the Taranaki and Waikato Basins. More recently, it has shifted its CSG focus from the Waikato to north-eastern Taranaki. It recently indicated that the assessed reserves have increased to around 900PJ, including contingent reserves based on an independent assessment by Netherland Sewell[20]. Solid Energy has not released any information on likely production costs, but has commented that the resource has a reasonable chance of being commercial. The proximity of these CSG tenements to the gas transmission system will have a positive influence on commercial viability.

2.5.3 Underground coal gasification

Solid Energy is also trialling underground coal gasification (UCG) in the Huntly area, with the opening of a pilot plant in April 2012. Solid Energy states that it has access to around 2 billion tonnes of coal resource in the Huntly area, much of which is too deep to mine using conventional techniques. Solid Energy considers that UCG may be a viable way to access the resource, which it assesses as having a large energy potential (>1,000 PJ)[21]. Solid Energy indicates that information from the pilot will be used to decide whether to proceed to a small-scale commercial operation.

2.5.4 Unconventional gas sources - implications for gas market

In the case of CSG and UCG resources in the Taranaki and Waikato regions, these are close to existing pipeline infrastructure and demand sources. This suggests that such resources could be developed and integrated into the gas market in a relatively straightforward manner, provided they are competitive in cost terms[22]. In the case of CSG resources remote from gas transmission infrastructure (for example Southland), commercialisation via pipeline sales would be much more challenging. The probable outcome is development as fuel sources for power generation, since this is relatively scalable and avoids the need for significant transmission investment (assuming connection into the electricity system is viable).

The major exception would be discovery of a very large and low cost resource, in which case this could conceivably underpin the development of a gas exporting industry (as is occurring in Queensland). Importantly, in the case of both modest and large scale finds, it appears relatively unlikely that

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20 www.coalnz.com/index.cfm/1,477,0,0/Solid-Energy-to-refocus-coal-seam-gas-development-in-Taranaki.html

21 See www.coalnz.com/index.cfm/1,477,0,0/Solid-Energy-begins-Underground-Coal-Gasification-successfully.html

22 Conventional reservoirs are typically produced from a relatively small number of wells. By contrast, CSG typically involves an ongoing programme of well drilling as the production 'footprint' is expanded. This makes CSG development relatively scalable compared to conventional gas production. However, CSG production is difficult to modulate over short timeframes because CSG wells react badly to being throttled back. This should not be an issue unless CSG production became a large proportion of the overall supply mix.

investment in pipelines would be justified to connect remote CSG resources to the main gas transmission system. This means that development of known CSG or UCG resources is unlikely to radically alter the pattern of flows within the existing gas transmission network (which is relevant to the transmission investment issues discussed elsewhere in this report).

The picture is somewhat more complex for shale resources. While the East Coast basin (where exploration effort is focussed) is connected to the gas transmission system, the pipelines are narrow gauge and would require significant investment to allow for high flow rates[23]. Whether such investment would be justified is difficult to assess. A further complicating factor is that exploration effort in the East Coast basin is directed at finding oil rather than gas. If substantial gas reserves are found in association with a commercial scale oil discovery, this would reduce the well-head gas price required to make pipeline investment viable[24]. This is in contrast to CSG and UCG production, where gas sales are the sole revenue source. As a result, shale gas derived from the East Coast basin represents a 'wildcard' in the gas supply/cost mix, with potential outcomes ranging from no effect through to a significant impact.

2.6 Potential for gas importation

Countries that have insufficient gas production to meet domestic demand are able to import gas via pipelines or in the form of liquefied natural gas (LNG)[25]. In New Zealand's case importation via pipelines is not viable, but LNG importation is technically feasible.

To enable LNG importation, an LNG receiving facility would need to be constructed. Historically, these have comprised double-walled storage tanks constructed to contain the LNG once it is offloaded, and regasification equipment, constructed in a port with facilities to accommodate large draught ships. Such facilities are expensive to construct, and require a significant throughput to make them economic.

In the mid-2000s, Contact Energy and Genesis Energy assessed the viability of gas importation as a backstop option, in the event that local production was insufficient to meet demand. At the time, they indicated the minimum scale for viability was likely to be around 60PJ per annum, or around 40% of gas use in 2011. Work on the concept was later shelved by the parties with the improving outlook for gas supplies in New Zealand.

Since that study was completed, there has been further technological development within the LNG sector. In particular, floating gas receipt facilities have been built which reduce the onshore investment requirement. One option is a floating buoy connected to the onshore gas pipeline system, which avoids the need for dedicated port infrastructure.

Another option is a dockside LNG vaporization and natural gas receiving facility. The first LNG terminal of this type was the Teeside Gas Port (TGP) developed near Middlesbrough in the United Kingdom, which went into service in February 2007. Upon delivery of cargo, a floating storage and regasification

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23 Investment would also be required in pipelines for gas gathering.

24 In this situation, gas could effectively be a by-product that needs to be addressed to facilitate oil production. This gas could be used locally (for example power generation), injected into a transmission system for remote use, or flared. However, the latter is unlikely to be acceptable for environmental reasons if it involved significant quantities of gas.

25 LNG is natural gas that has been super cooled to–162°C, where it condenses into liquid form. This reduces its volume to around 1/600th of its gaseous state, and facilitates transportation in specially designed ships with insulated tanks.

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unit (FSRU) moors at the jetty to regasify LNG onboard and deliver high-pressure natural gas ashore into the transmission system. The TGP is reported as being capable of delivering gas at a baseload rate of around 0.4 PJ/day, with peaking capability up to 0.6 PJ/day.[26]

Figure 13: TGP onshore facilities and FSRU

Source: Excelerate Energy

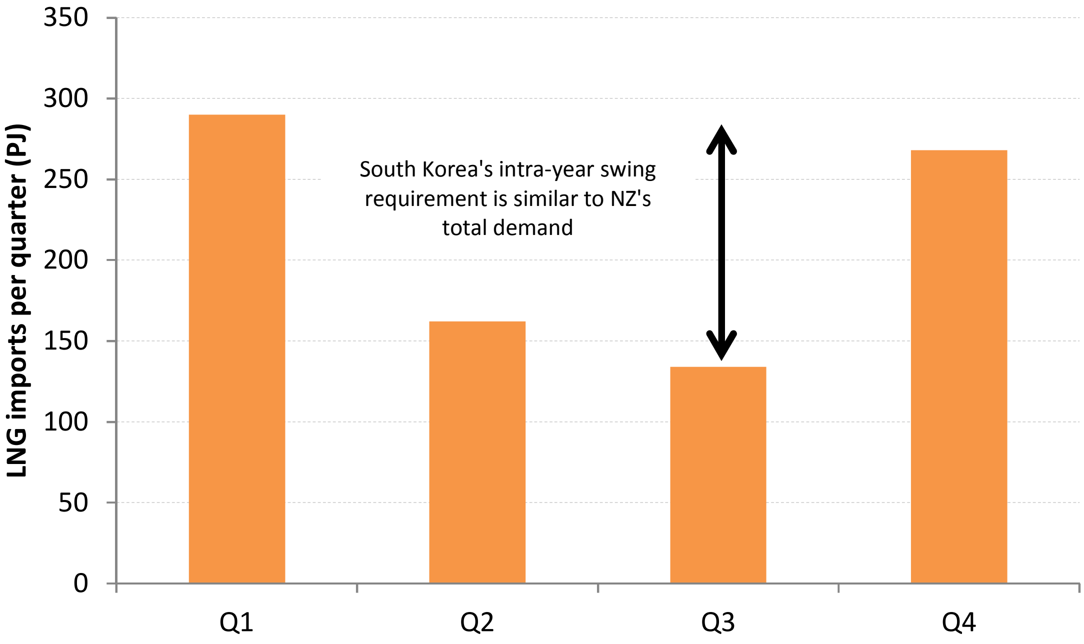
A key feature of these types of facility is the reduced investment requirement in onshore facilities. This reduces cost and development time, and provides more flexibility to adjust to changing market conditions if required (such as a subsequent local gas find). For example, the TGP is reported to have been brought into service within 12 months of site selection, and at a cost that was roughly 10% of a conventional land-based LNG receiving terminal.

A facility of these types could be of use in New Zealand in the (relatively unlikely) scenario that domestic exploration success was extremely poor, or where external sources were required to provide a 'top-up' to meet seasonal or other swing requirements. In that context, it is relevant to note Queensland is emerging as a major exporter of LNG. By 2016, LNG exports from committed investments are expected to exceed 1,000 PJ/year, and a similar volume of additional projects are actively being considered.

The bulk of this export trade is destined for markets in north Asia, which have a significant seasonal demand profile. For example, South Korea's quarterly swing requirement is greater than New Zealand's annual demand, as shown in Figure 14.

[26] See www.excelerateenergy.com/project/teesside-gasport

Figure 14: Seasonal pattern of LNG gas imports into South Korea



Source: Contact Energy presentation to investors

New Zealand's counter-cyclical demand profile and relatively short steaming time from Queensland (~3.5 days) mean that gas importation could provide a viable supply backstop in a low exploration success scenario, and/or provide additional gas swing. Likewise, if a future large gas find in New Zealand in a remote basin were to be developed for LNG, it would probably be exported primarily to north Asian customers with a similar seasonal demand pattern to that in Figure 14. Again, it is possible that some production might be diverted to the domestic New Zealand market.

If a gas importation facility were developed, it is likely that it would be sited to minimise steaming time, and be close to major load centres and/or gas transmission pipelines. Unless a conventional LNG storage facility was constructed, proximity to underground gas storage capacity is likely to be an advantage, to minimise tanker unloading times and facilitate turnarounds. These factors suggest that Taranaki would probably be the favoured location. This is turn suggests that any LNG facility would be unlikely to alter the radial gas flow from Taranaki (which is relevant to the transmission investment issues discussed elsewhere in this report).

2.7 Gas supply and price scenarios

While there is uncertainty about the success rate for future gas discovery, it would be wrong to conclude that gas *supply* is uncertain. On the contrary, for practical purposes, the physical availability of gas is assured. In the extremely unlikely case of very limited or no exploration success, New Zealand could import gas to supplement or replace its domestic sources (as occurs in many other countries). In addition, as set out in sections 3.2 and 3.3, it is likely that if New Zealand reserves started to reduce, the petrochemical and power generation sectors would scale back their demand. This would have the effect of preserving New Zealand's gas supply for those users that valued it most.

For these reasons, the supply scenarios described in this report are expressed in terms of the gas prices that could prevail in the New Zealand market, rather than specific physical conditions. The scenarios are used later in this report to consider the potential implications of each scenario for gas demand, and the pipeline investment issues.

It is important to emphasise that these price scenarios are not forecasts. Rather, they represent alternative 'futures' that could unfold over the 2012-2027 period. They are deliberately structured to span the broad range of outcomes that could plausibly emerge in this timeframe.

Three specific scenarios have been developed, as set out in Table 2.

Table 2: Gas price scenarios

Gas price scenario	Gas price (real $2012)	Broad description
Low prices	$4.50/GJ	In this scenario exploration success leads to a lengthening of reserves to production ratios. Prices subside due to plentiful gas supply and strong drivers on sellers to realise sales (for example to maximise liquids production). This scenario could arise from further exploration success in Taranaki, and/or success in other basins close to the NI transmission system, or with unconventional gas
Medium prices	$7.00/GJ	In this scenario there is continuing adequate gas supply, and moderate drivers on sellers to realise sales
High prices	$12.00/GJ	In this scenario there is decline in exploration success leading to a reduction in reserves to production ratios. Alternatively a very large gas find close to the existing transmission system leads to export parity pricing based on LNG production.

Notes: 1. Prices shown are for notional gas supply contracts with multi-year terms and assume flat delivery profiles. 2. Prices exclude transmission costs and other charges (for example carbon).

Figure 15 shows a range of gas price indicators and the prices assumed in the three scenarios. While the data is expressed in current dollars for ease of comparison, it is important to note that some differences remain such as the degree of reserves risk etc.

Figure 15: Gas price comparisons

Sources: Derived from company disclosures, Australian Energy Market Operator and Electricity Commission reports, The Economist. Dates indicate period when price was in force (all data adjusted at PPI to 2012 dollars). Est. = estimate. Rep. = reported.

Key observations from the chart are:

- The low price scenario assumes that contract prices move to a level similar (in real terms) to that which applied under historic Maui arrangements[27], or reported as applying in recent sales contracts by independent gas producers[28];
- The medium price scenario assumes that contract prices move to a level that similar to (though somewhat lower) than that observed in the period 2006 to 2011;
- The high price scenario assumes that prices move to a level between the estimated netback value for sellers of LNG in Queensland, and the prices reported as being paid on average by LNG buyers in Asia.

27 Estimated at $3.00/GJ for wholesale buyers in 2001. Note that Maui joint venturers were paid a lower price because the Crown was an intermediary and charged a margin on sales.

28 It is important to note that the recent disclosed data includes sales where the buyer bears the risk of reserves shortfall (whereas estimates for some other contracts in the chart provide more assurance about reserves risk).

2.8 How quickly might these scenarios unfold?

Anecdotal evidence indicates that wholesale gas contracts have recently been trading at around \$6.00/GJ, although some end-user deals are reported to have been signed at around \$5.50/GJ. For buyers or resellers that are prepared to take on deliverability and reserves risk, prices appear to be significantly lower (as shown in Figure 15). These factors suggest that current conditions are somewhere between the medium price and low price scenario.

For the low price scenario to fully emerge would require major exploration success close to the existing gas transmission system. While far from certain, this is a credible scenario, given the combination of higher oil prices and improved technology underpinning exploration activity in Taranaki, the ramp up in effort to extend existing fields, and the beginnings of what may be considerable interest in unconventional resources. In addition, as discussed later, methanol production is a 'bellwether' of the supply / demand balance in New Zealand. In this respect, having mothballed its plant when gas supply became tight in the early 2000's, Methanex is now investing a considerable amount of money bringing its Taranaki production capability back into service. This would appear to indicate that Methanex has confidence that New Zealand is entering a period of greater gas availability.

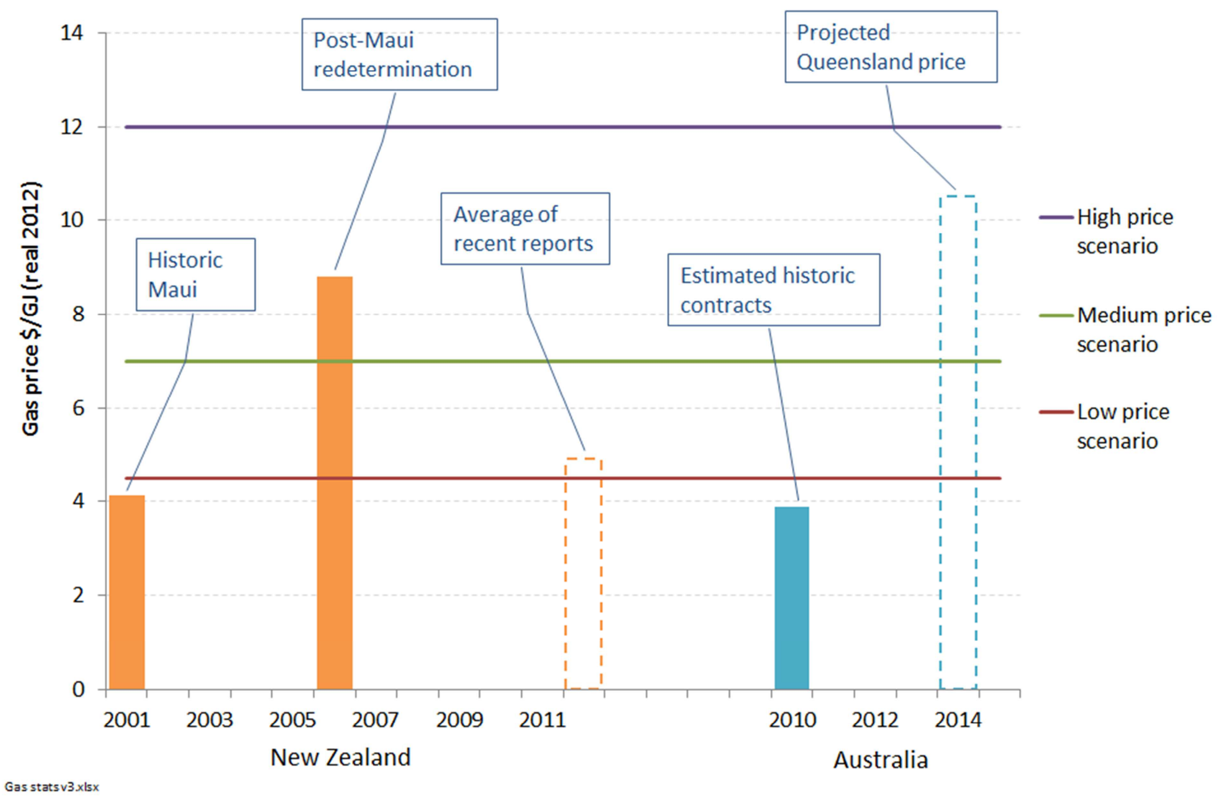
In principle, a low price scenario could emerge relatively swiftly (perhaps around 2-3 years, depending on investment requirements), if sufficiently large gas reserves were to come to market. The polar opposite high price scenario assumes a shrinking domestic supply base, leading to declining reserves to production ratios, or a large find close to the existing transmission system that sparks the development of a liquefied natural gas export industry.

In contrast to the low price scenario, this outcome is very unlikely to emerge without warning. Instead a declining reserve position would be evident in official statistics reported over a number of years. Nor is a sudden unexpected failure of any existing gas field likely to trigger this scenario, because supply is diversified across a number of sources. Furthermore, a tightening supply outlook would almost certainly induce a reduction in demand by some users, effectively extending the life of remaining reserves. Similarly, a large find that allowed development of an liquefied natural gas export industry would take some years to develop. For these reasons, the high price scenario would probably require at least 5 years before it could occur.

In this respect, it is also interesting to note that the energy price situations in Australia and New Zealand appear to be reversing. Gas prices in New Zealand have been higher than in Australia[29] over the last decade. Now, however, it appears that the combination of the recent gas developments in both countries (New Zealand's recent exploration successes, and Australia's 'internationalisation' of its gas price through development of LNG export facilities) may be reversing this position, as shown in Figure 16.

29 At least in the Eastern States. The situation is somewhat different in Western Australia.

Figure 16: Gas price trends in New Zealand and Eastern Australia



Source: Concept analysis based on data from company reports and disclosures, AEMO

2.9 Cost of swing

The prices in the scenarios are for the gas 'commodity', and reflect contracts with minimal swing factors[30], (i.e. gas is delivered on a relatively flat daily[31] profile over the year). In fact, many gas users need to vary their demand across the year due to seasonal or other factors (such as hydrological conditions which affects gas demand for power generation).

The swing requirement of the system can be provided from a variety of sources:

- Supply swing – producers can run their plant below full output to provide flexibility to users. However, this defers the receipt of oil and gas sale revenues and extends the period when operating costs will be incurred. The former can be addressed to some extent by installing gas reinjection facilities (to avoid deferral of liquids revenue) but this increases costs;

- Underground storage – surplus gas can be stored in a depleted reservoir for later production and use. New Zealand currently has one underground gas storage facility at Ahuroa in Taranaki. Gas storage involves costs for reinjection and losses;

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30 Swing factor refers to the ability provided in a contract for the user to vary the rate of gas delivery up and down, to meet changing daily demand or other needs. The swing factor is defined as (maximum daily quantity x 365) / annual quantity.

31 Gas users may also wish to vary their demand within a day. This requirement is generally met by changes in linepack, which is the gas 'stored' by altering the pressure within gas transmission pipelines.

- Demand swing – flexibility for some users may be provided through other users altering their demand in an offsetting fashion (for example by switching to an alternative fuel source).

All of these sources of flexibility have some cost, and this generally rises with the degree of flexibility being sought. The cost of swing is very relevant to some users, because they require a high degree of flexibility. The implications of this issue for projected gas demand are discussed later in this report.

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3 Gas demand scenarios

Chapter summary

- Long-term gas demand in New Zealand is likely to vary significantly between the different price scenarios, ranging from 250 PJ/year in the low price scenario down to 75 PJ/year in the high price scenario
- As between the scenarios, the sectors where the main change in gas demand occur are petrochemical manufacturing (especially methanol production) and power generation – as these sectors are the most sensitive to changes in wholesale gas prices.
- The rolling off of existing gas contracts for power generators, coupled with the development of gas supply flexibility capability such as the Ahurora gas storage facility and gas reinjection at Pohokura, is likely to mean that gas-fired generators will respond even more flexibly to changing gas prices. This increased gas supply flexibility will likely also mean that gas-fired power generation will on average consume less gas than historically, because of their better ability to avoid operation during low electricity price periods.
- Gas demand for other industrial, commercial and residential users is relatively steady across the scenarios. This is because:
  - even in a high gas price world, gas has a relatively strong position compared to alternative fuels due to the significantly lower process heat boiler capital and non-fuel operating costs compared with coal and biomass alternatives, such that any switching away from gas is likely to be relatively modest; and
  - in a low gas price world, the growth in gas demand will be limited by the growth in demand for energy services which will be closely linked to the growth in GDP. This is likely to be of the order of a few percent a year.
- This much greater demand variability of the petrochemical and power generation sectors illustrates the valuable 'shock-absorber' role fulfilled by such sectors:
  - they provide ready markets for gas when it is plentiful (thereby significantly lowering the cost of producing oil, making New Zealand a more attractive place to invest to produce hydrocarbons); but
  - they scale-back demand if gas reserves become scarce (thereby extending the life of reserves for the majority of gas users).

This chapter describes the broad composition of gas demand in New Zealand at a sectoral level. It then considers how demand going forward might alter under the different price scenarios discussed in Chapter 2.

The demand scenarios in this chapter are described primarily in terms of annual quantities. The following chapter uses this information to develop projections of peak demand in each year. This subsequent step is necessary because the critical factor determining the need for pipeline investment is gas demand at times of peak usage, rather than annual demand.

3.1 Historic annual gas demand

As is illustrated by Figure 17, New Zealand's gas demand can be separated into three main sectors:

- petrochemical production – where gas is used as a feedstock. This segment of demand is dominated by the production of methanol at the Motunui and Waitara Valley plants owned by Methanex Corporation, and ammonia urea production (for fertiliser) at the Kapuni plant owned by Ballance Agri-nutrients (Ballance);

- power generation – where gas is used as a fuel source in baseload and cogeneration plants (which operate on a more or less continuous basis), and as a flexible fuel source for power stations that operate on an intermittent basis (for example to meet peak demand, or compensate for reduced hydro generation during droughts). This segment of demand is dominated by gas used in the power and cogeneration stations owned by Contact Energy, Genesis Energy, Mighty River Power and Todd Energy; and

- direct use – where gas is used for space or water heating, or to generate process heat for industrial applications. This category includes over 250,000 users, covering industrial (for example meat processors), commercial (for example hotels), and residential customers. Although this category has by far the greatest number of users, it is the smallest in terms of overall demand, and accounted for approximately 28% of total New Zealand consumption in 2011. Within this segment, residential demand accounted for only 3.5% of total New Zealand consumption in 2011.

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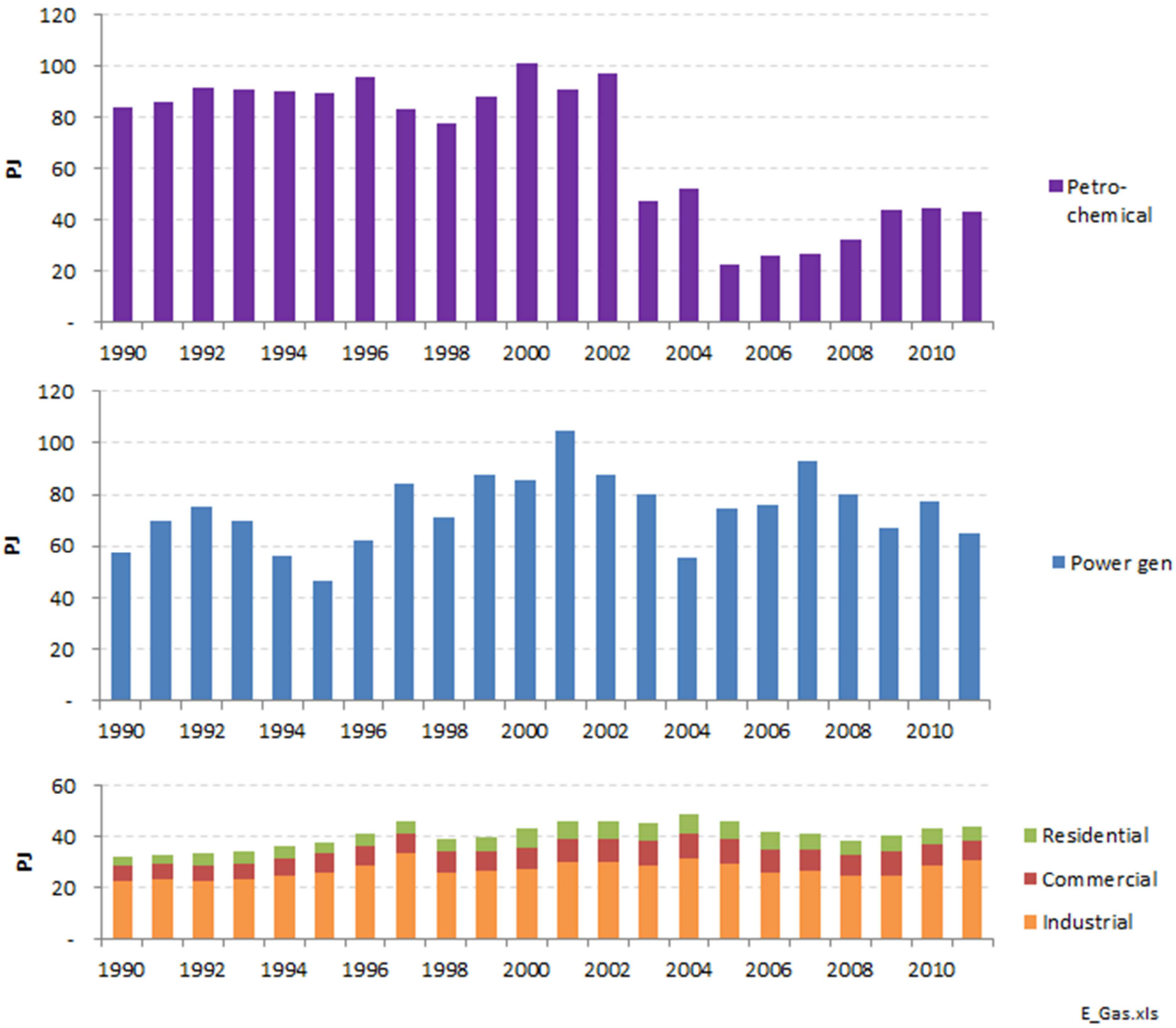
Figure 17: Historic New Zealand gas demand



Source: Ministry of Business, Innovation and Employment, Energy Data File, July 2012. Excludes gas production losses and own use, and transmission losses.

The potential trends in annual demand for each segment are discussed in the following sections.

3.2 Petrochemical sector

Figure 18 shows the make-up of gas demand for the petrochemical sector in 2011, and the extent to which spare capacity existed[32] at existing processing plant.

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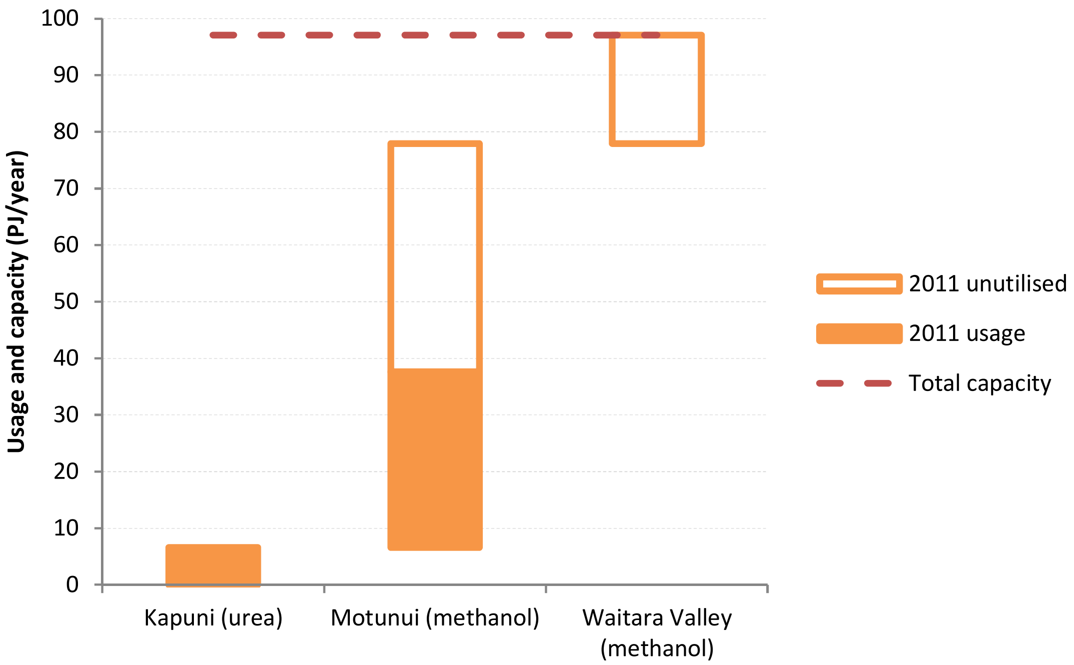
32 Based on nominal plant capacity. As discussed later, some plant has been mothballed and may be brought back into service.

Figure 18: Petrochemical sector gas demand and capacity (2011)



Sources: Estimates derived from data in company and broker reports

The key observations are:

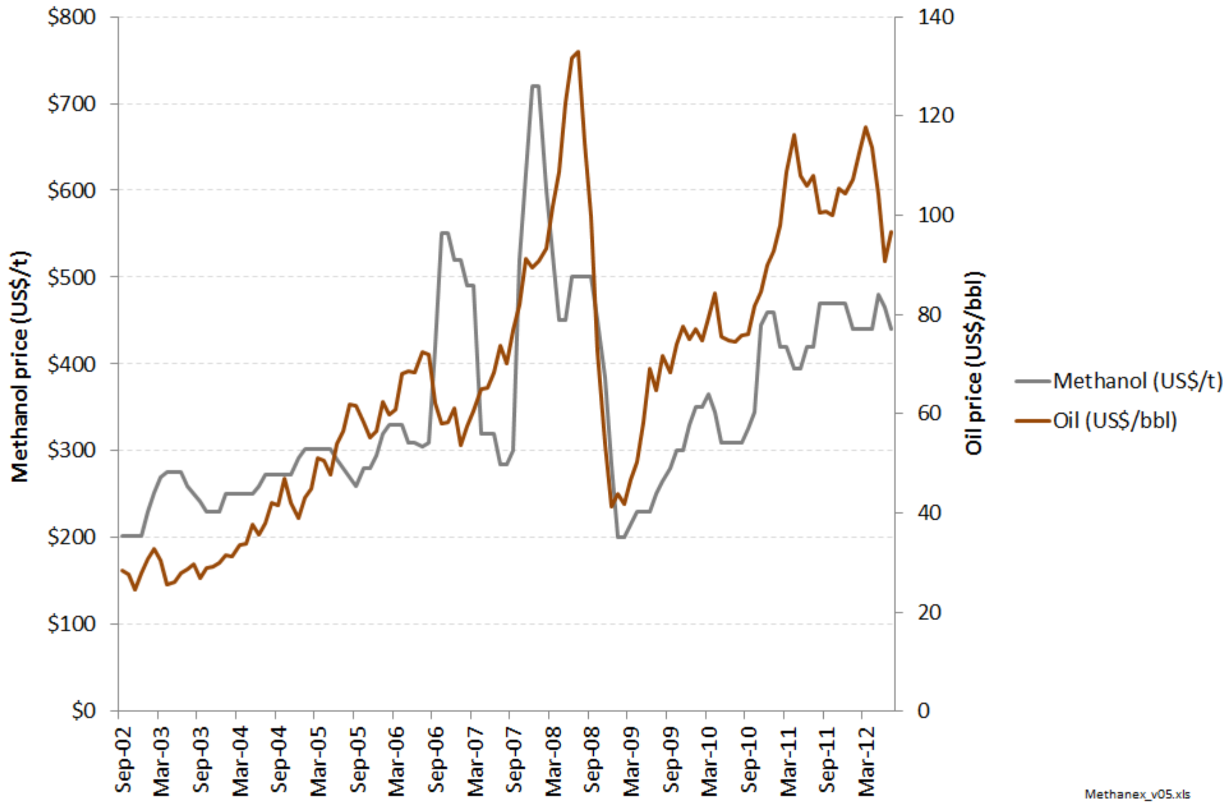
- production of urea accounted for a relatively small proportion of overall demand (6.5 PJ versus 37 PJ) and was running at effective full capacity. In fact, this has been the general pattern of production at Ballance's ammonia urea plant over recent years;
- production of methanol in the Motunui plant was slightly below 50% of full capacity. There was also unutilised capacity at the Waitara Valley plant (which has been shut-down since 2008); and
- if all plant was run at full capacity the total gas demand would be close to 100 PJ/year. This underlines the significance of potential gas demand from this segment.

Looking ahead, the question arises as to what level of demand to expect for petrochemical production under the three price scenarios set out in section 2.7. Given the relative sizes of gas demand for methanol and ammonia urea production, the balance of this section principally focusses on the former use.

3.2.1 Methanol production

The economics of methanol production are essentially determined by the international price for methanol, and the costs of manufacturing in New Zealand relative to other locations. As shown in Figure 19 below, the international methanol price is strongly correlated to oil prices.

Figure 19: International oil and methanol prices



Source: Concept analysis using Methanex and World Bank data

Figure 20 shows the estimated breakeven gas price based on historic methanol prices and estimated manufacturing costs (excluding gas feedstock).

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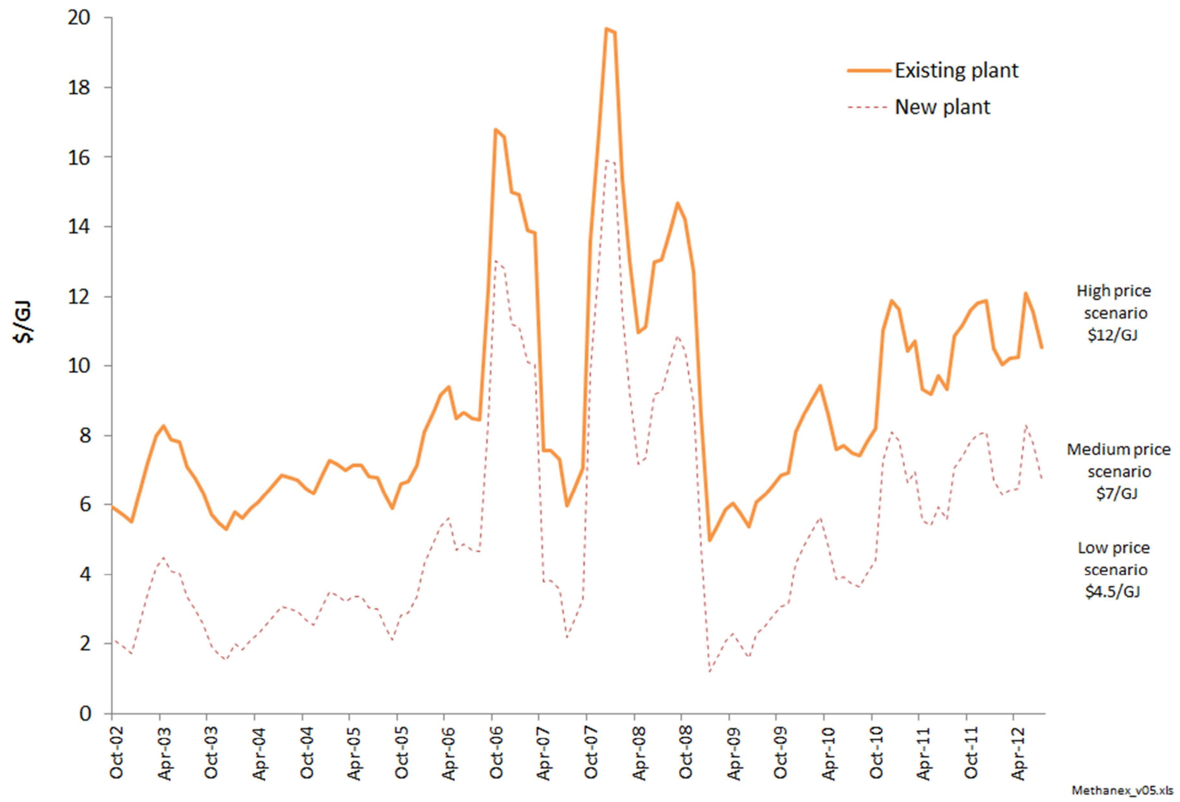
Figure 20: Estimated breakeven gas price for methanol manufacturing (nominal)



Source: Analysis derived from company and broker reports. The estimated breakeven value is based on posted Asian methanol prices converted to NZD at prevailing exchange rates (less a discount as realised prices appear lower than posted prices), minus transport costs, and manufacturing costs

The chart shows estimated breakeven prices for existing and new manufacturing plant in New Zealand. In both cases the values include an allowance for operating and recovery of capital costs. In the case of existing plant, the stay-in-business capital cost has been estimated based on the reported capital expenditure that would be required to bring the mothballed Waitara Valley plant back into production. The estimate for new plant costs is based on figures attributed to Methanex in late 2011.

The estimated breakeven prices have varied considerably over time, reflecting changes in the international methanol price, and the exchange rate. Looking ahead, demand for methanol is expected to continue to grow strongly[33] suggesting that product prices will remain around or above current levels on average (although shorter term fluctuations are likely).

On the basis of this methanol price outlook, the following observations apply:

- under the high gas price scenario methanol production from existing plants is likely to be unattractive, other than for brief periods when methanol prices are very high and/or the New Zealand dollar is low. However, the economics of maintaining plant capacity in New Zealand for

[33] Global demand over the period 1997-2010 has grown at 4.7% on a compound average basis, and growth (albeit at a slower rate) has been maintained since the global financial crisis emerged in 2007).

brief expected periods of operation is unlikely to be attractive[34]. Investment in new manufacturing capacity in New Zealand is extremely unlikely under the high gas price scenario;

- under the medium gas price scenario methanol production from existing plant is expected to be economic, but some capacity is likely to operate as a swing producer, increasing output when conditions are favourable and throttling back at other times. It appears unlikely that investment in new manufacturing capacity would occur under the medium gas price scenario; and

- under the low price scenario methanol production is likely to be attractive, (other than for brief periods when market conditions are unfavourable). In this scenario, it would be likely that methanol plant would run at full capacity most of the time. Furthermore, it appears that investment in new manufacturing capacity could potentially be viable in this scenario[35] (provided sufficient feedstock is available).

Developments in the market are consistent with these observations. As shown in Figure 21, gas demand for methanol production declined in the mid-2000s as gas prices increased from approximately $3/GJ to around $6/GJ (nominal terms) following the downward re-determination of remaining Maui reserves.

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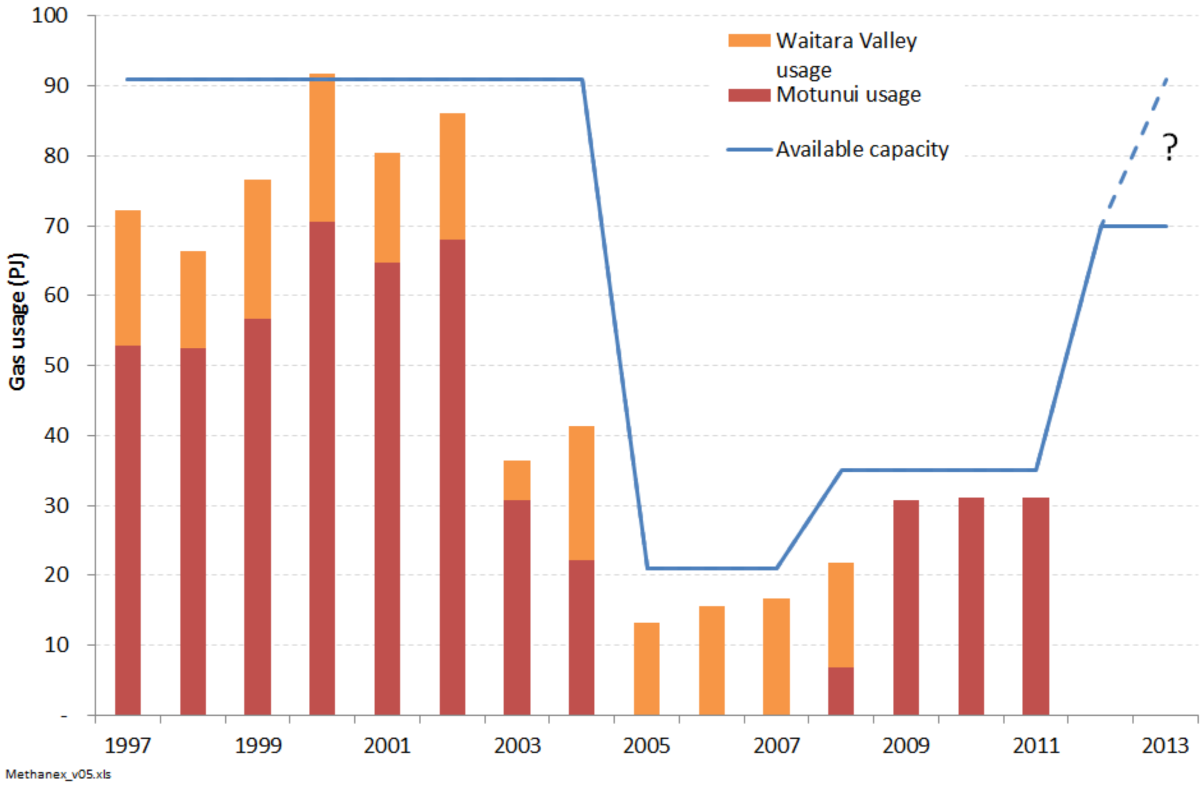
[34] Plant might be relocated to sites where gas costs are lower. For example Methanex is understood to be relocating a processing train from Chile to Louisiana because United States gas prices have fallen steeply with the steep increase in production of shale gas.

[35] Noting that the relative attractiveness of investment in other regions would influence this decision, such as new sites in North America.

Figure 21: Methanol processing capacity and actual usage



Source: Company reports and media statements

More recently, as increased gas supply has become available and prices have declined in real terms, there has been an increase in gas demand for methanol production. There has also been some reinvestment to allow mothballed capacity to be brought back into service such that both trains at Motunui are now operational. Furthermore, in mid-2012, Methanex was reported to be considering the re-commissioning of the Waitara Valley plant, which would allow a restart of production in 2013.

Methanex's moves to progressively re-commission capacity, and increase utilisation would appear to indicate that Methanex believes that New Zealand is entering a period of increased gas availability.

3.2.2 Ammonia urea production

Ammonia urea is used as a nitrogen rich fertiliser. Historically, around half of New Zealand's requirements have been produced by the Ballance Agri-Nutrients production facility at Kapuni. The balance of New Zealand's ammonia urea use has been sourced overseas, with the cost of imported product (including transport) effectively capping the amount that the Kapuni plant can pay for gas (after allowing for other manufacturing costs).

Analysis indicates that the breakeven gas cost for ammonia urea production at Kapuni is likely to be around $11-12/GJ, based on a landed cost for competing imported product of $350/tonne. It is important to note that this calculation is based on cash production costs with an allowance for stay-in-business capital cost (Ballance Agri-Nutrients announced that $30 million was invested in maintenance and capital improvements in 2012). However, it does not allow for return on capital for existing investment or expansion of existing capacity.

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This analysis suggests that continued full utilisation of capacity (6.5PJ/year) is likely under the low price and medium price gas scenarios. Under the high gas price scenario, ammonia urea production would become marginal and possibly uneconomic, depending on the landed cost of importing alternative supply.

Recent announcements by Ballance are consistent with these general observations. In particular, in July 2012 the company announced that it had recently secured gas supply arrangements until 2020, and re-consented the facility until 2035[36]. This suggests that there is a high likelihood that the plant will operate at or close to full capacity throughout the projection period 2012-2027, unless there is a marked upward movement in gas prices.

3.2.3 Potential implications for gas transmission investment

Under the low and medium price scenarios there is likely to be some expansion of gas demand for use as a petrochemical feedstock. This raises the issue of whether any such growth would require expansion of gas transmission capacity.

In terms of increased use of existing plant, no such expansion is likely to be required as these facilities are located in Taranaki close to gas sources and major gas pipelines. Likewise, expansion of existing processing facilities is unlikely to require any significant pipeline investment for the same reasons. The only situation where pipeline expansion might be required to service petrochemical manufacturing would be to service new plant outside of Taranaki. However, in that case the petrochemical processing plant would presumably locate close to the (new) gas supply source.

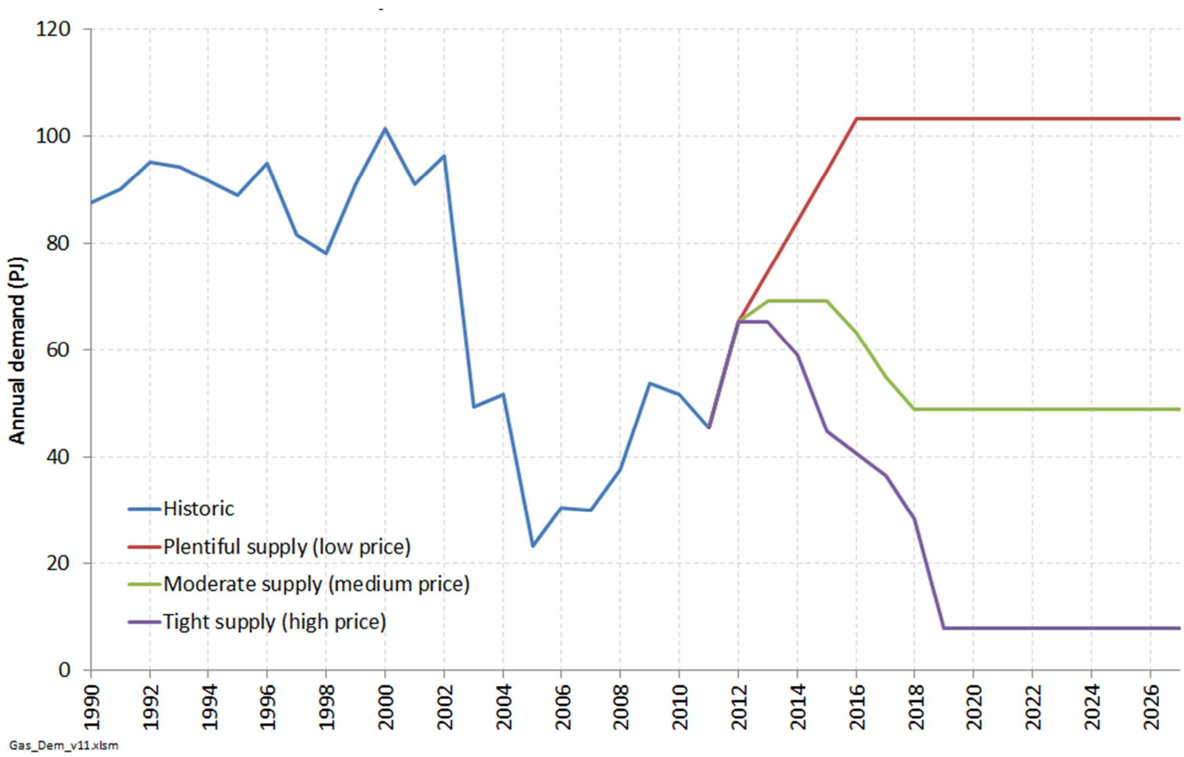
3.2.4 Summary of petrochemical demand for different price scenarios

Figure 22 below presents the projections of demand from the petrochemical sector for the different price scenarios, as well as historic demand from 1990. The consumption assumed for the three scenarios is as follows:

- Low price scenario – Methanex moves to close to full production from both its Motunui trains and its Waitara Valley plant by 2016
- Medium price scenario - Methanol production shifts to just one Motunui train by 2018
- High price scenario - Methanol production is progressively scaled back until it ceases completely in New Zealand by 2019. Petrochemical demand beyond this date consists only of Ballance's production of urea (which is assumed to be constant in all three scenarios).

[36] http://www.ballance.co.nz/news/winter+2012/kapuni+future+secure

Figure 22: Projected petrochemical sector demand for the different price scenarios



Source: Concept estimates

3.3 Power generation

As Figure 4 and Figure 17 have previously illustrated, electricity generation has been the biggest use of gas in New Zealand over the last couple of decades, but has exhibited considerable year-on-year volatility.

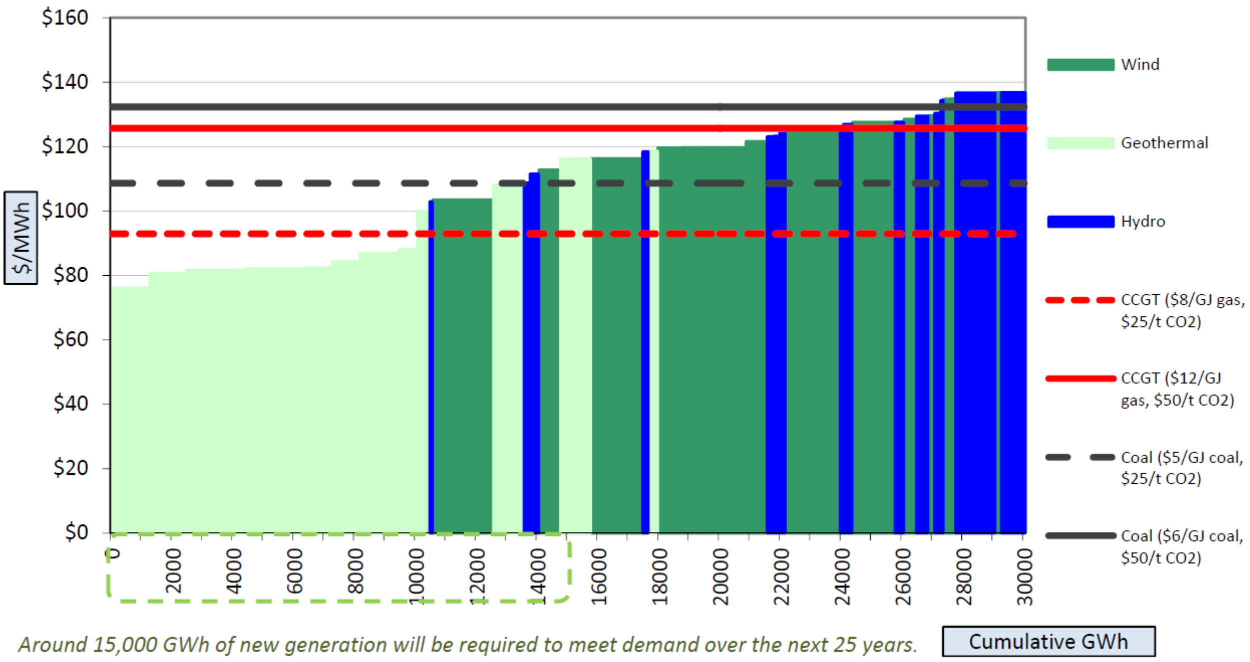
In considering future demand for gas for power generation, it is useful to distinguish two distinct sub-segments. Gas can provide fuel for so-called baseload power stations (which run more or less continuously). Gas can also be used as a flexible fuel source for 'peaking' power stations, which mainly operate at times of high electricity demand, or when generation from renewable power stations (such as wind or hydro plant) is reduced.

This distinction is important because the competitive position of gas in the two segments (for both new and existing power stations) is very different.

3.3.1 Baseload generation development

Figure 23 below shows recent analysis produced by the Ministry of Business, Innovation & Employment (MBIE) showing the Ministry's estimated cost-supply curve for new baseload generation in New Zealand.

Figure 23: LRMC of new generation - Energy Outlook Assumptions



Source: "*Introducing the Electricity Demand and Generation Scenarios*", July 2012, Ministry of Business, Innovation & Employment

The horizontal red lines indicate MBIE's estimate of the (long run marginal cost) LRMC of a combined cycle gas turbine (CCGT) at different gas prices. If gas prices are $8/GJ (the dotted red line), this graph suggests that there is unlikely to be new baseload gas-fired generation in the next 10 to 15 years at least, with growth in electricity demand predominantly being met by new geothermal generation.

This is consistent with the fact that three out of the four scenarios proposed by MBIE for its Electricity Demand and Generation Scenarios (EDGS) study have no new baseload gas-fired generation being developed. In these scenarios, new generation build is dominated by geothermal and wind projects.

Only one of the four scenarios proposed by MBIE for EDGS has new CCGT plant being built (along with some new geothermal and wind). This scenario assumes a high level of gas exploration success in the North Island, none of which is so large as to be economic for export as LNG (as that would mean New Zealand prices would rise to export parity levels). It also assumes CO_2 prices remain around $10/t$CO_2$ for the foreseeable future.

As shown in Figure 23, at a gas price of $8/GJ and CO_2 price of $25/t$CO_2$, MBIE estimates that the LRMC of a new CCGT will be approximately $92/MWh

However, if gas prices were at a level consistent with the Low price scenario for this study ($4.5/GJ), and CO_2 prices were at $10/t$CO_2$, this LRMC would drop to approximately $62/MWh[37].

This would make it competitive with renewable alternatives. At such prices, it would seem plausible that new CCGT investment would occur. However, there are a number of other factors to consider.

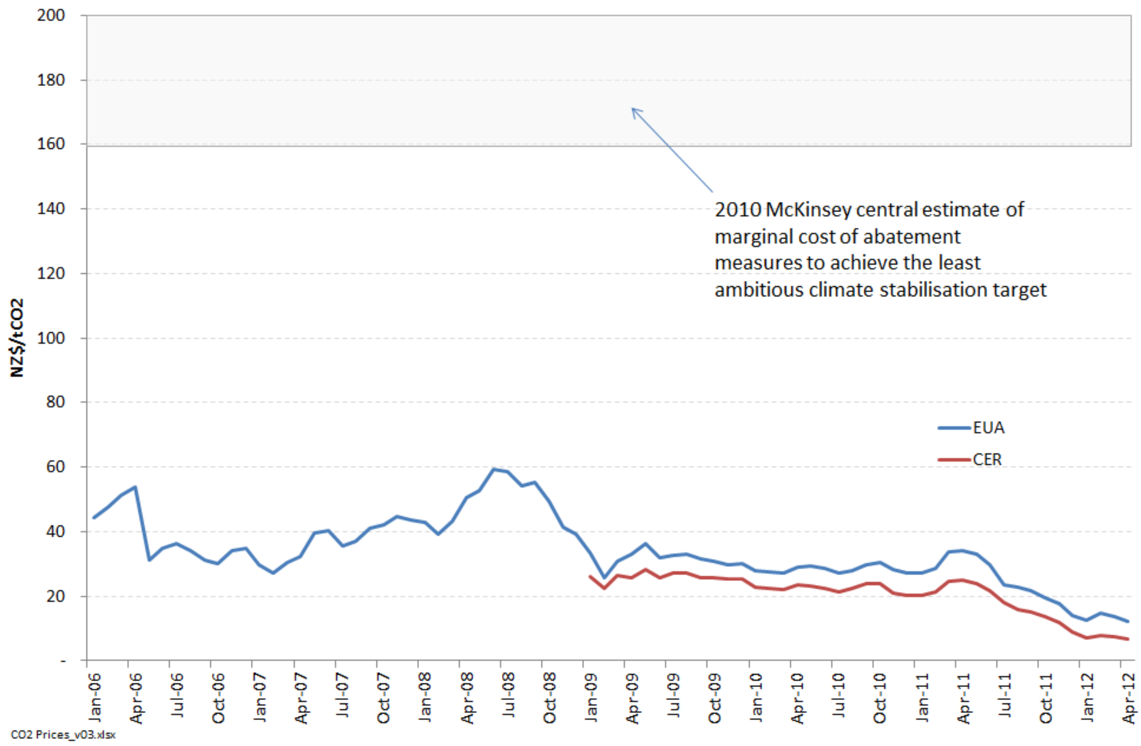
[37] This assumes a heat rate of 7,050 GJ/GWh, and an emissions factor for gas of 0.053 tCO2/GJ.

Firstly, could a generator secure gas at such a price for a sufficient length of time? A gas supply contract of at least 10 years would probably be required to prompt new power station investment. In this respect, although section 2.8 indicates that near term wholesale gas prices appear to be approximately $5-6/GJ, these are for deals with shorter duration and/or no firm reserves obligation on the gas seller.

The second issue is whether CO_2 prices are likely to remain at their current low levels. Figure 24 shows that over the past few years the price of CO_2 for the two main international schemes[38] has softened considerably, such that the international price of CO_2 is now approximately NZ$10/t$CO_2$

It is possible that CO_2 prices could continue at such low levels going forward. However, it is also possible that CO_2 prices could rise significantly. For comparison, Figure 24 also shows the range of prices indicated by a 2010 McKinsey study that shows the estimated marginal cost of abatement measures to achieve the least ambitious IPCC climate stabilisation target.

Figure 24: CO_2 prices

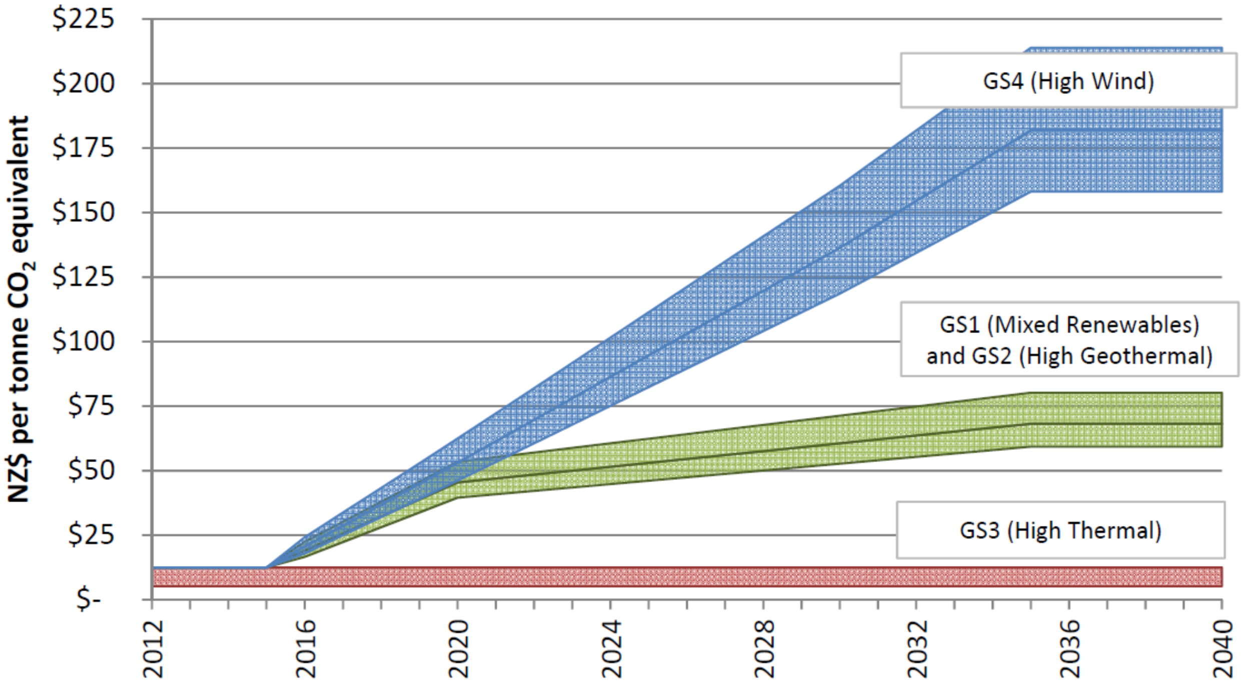


Source: Concept analysis using Intercontinental Exchange data

MBIE has also proposed CO_2 price scenarios as inputs into the development of the generation scenarios for the EDGS exercise. Such scenarios were based on the International Energy Agency's *World Energy Outlook*. These scenarios are shown in Figure 25 below.

38 The EUA price is for EU Allowances that can be traded in the EU Emissions Trading Scheme. The CER price is for a Certified Emissions Reduction unit issued by the Clean Development Mechanism (CDM) Executive Board under the rules of the Kyoto Protocol.

Figure 25: Proposed carbon price assumptions for MBIE generation scenarios



Source: "*Introducing the Electricity Demand and Generation Scenarios*", July 2012, Ministry of Business, Innovation & Employment

As can be seen, in three out of four scenarios, CO_2 prices rise significantly from current levels.

On balance, it is considered likely that there will be more upward pressure on CO_2 prices than downward pressure.

The last issue which will determine the likelihood of a new baseload CCGT investment is electricity demand growth. In this respect, there is no immediate need for new baseload generation investment. Indeed, current indications are that the electricity market is moving into surplus driven by low demand growth (as illustrated in Figure 26 below), and continuing supply growth from a number of already committed projects.

This historic low level of demand growth is considered likely to continue for some time – not least because of a recent announcement by Norske Skog that it will be halving production at its Tasman mill, leading to a reduction in electricity consumption of approximately 500 GWh (equivalent to approximately one year's total demand growth). In addition, there are some other relatively low cost geothermal and wind options which have not been committed, but which have secured all the necessary consents and may be more likely to go ahead of a new CCGT – even under a low gas price scenario[39].

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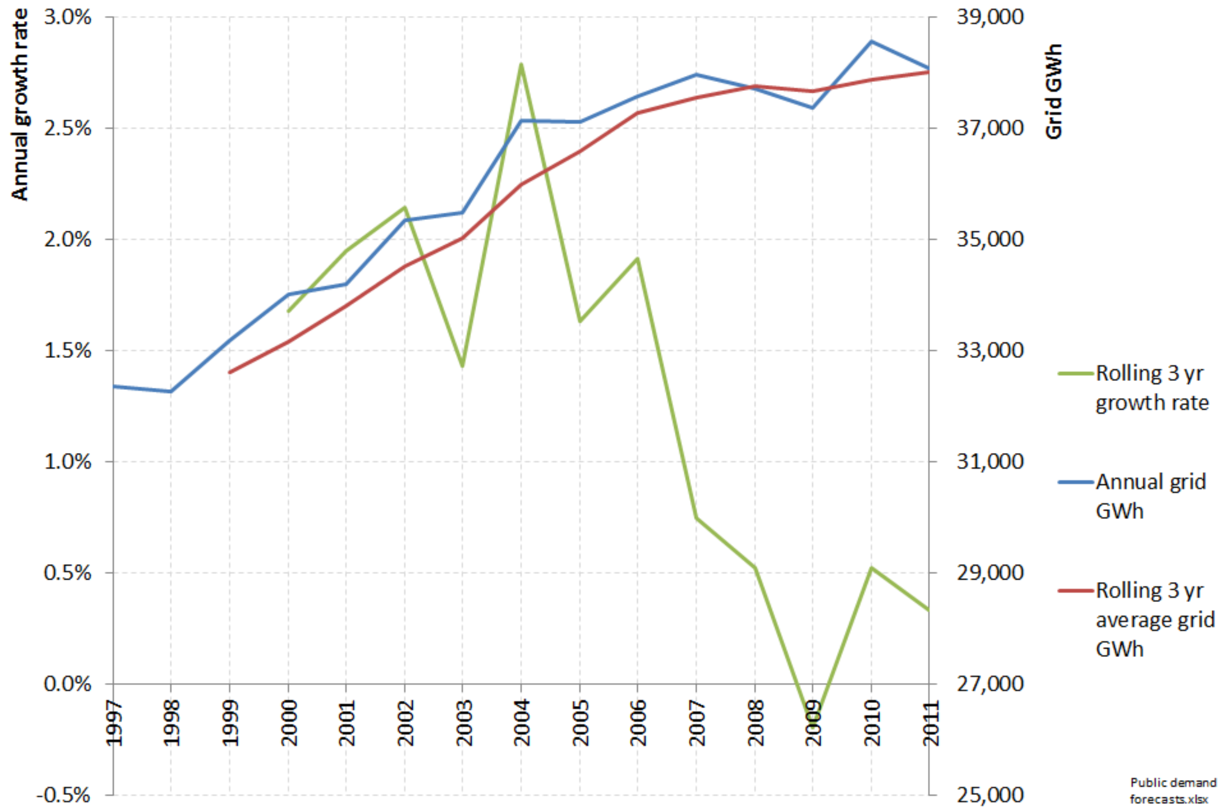
[39] The scale of demand growth reduction has caused a number of generators to postpone their projects. The only recent demand forecast from a central agency is in Transpower's 2012 Annual Planning Report (APR) published in March 2012. Their prudent peak demand forecast for 2013 is 12.4% lower compared with their 2011 APR forecast. And they are projecting annual growth rates beyond 2013 to be lower than in their 2011 APR forecast.

Figure 26: Historic movements in annual New Zealand electricity demand



Source: Concept analysis using Electricity Authority Centralised Data Set data.

Finally, it has been reported that the owners of the Tiwai aluminium smelter are seeking to renegotiate the supply contract with Meridian Energy. It is very difficult to predict the outcome of these discussions, but if the Tiwai smelter were to close or reduce its demand, this would have a significant impact on the timing of new generation investment requirements (given that the smelter's annual demand of up to 5,400 GWh is equivalent to approximately nine years of historic demand growth)[40].

For these reasons, it appears unlikely that any new gas-fired generation would be required (even under the low gas price scenario) until 2019 at the earliest.

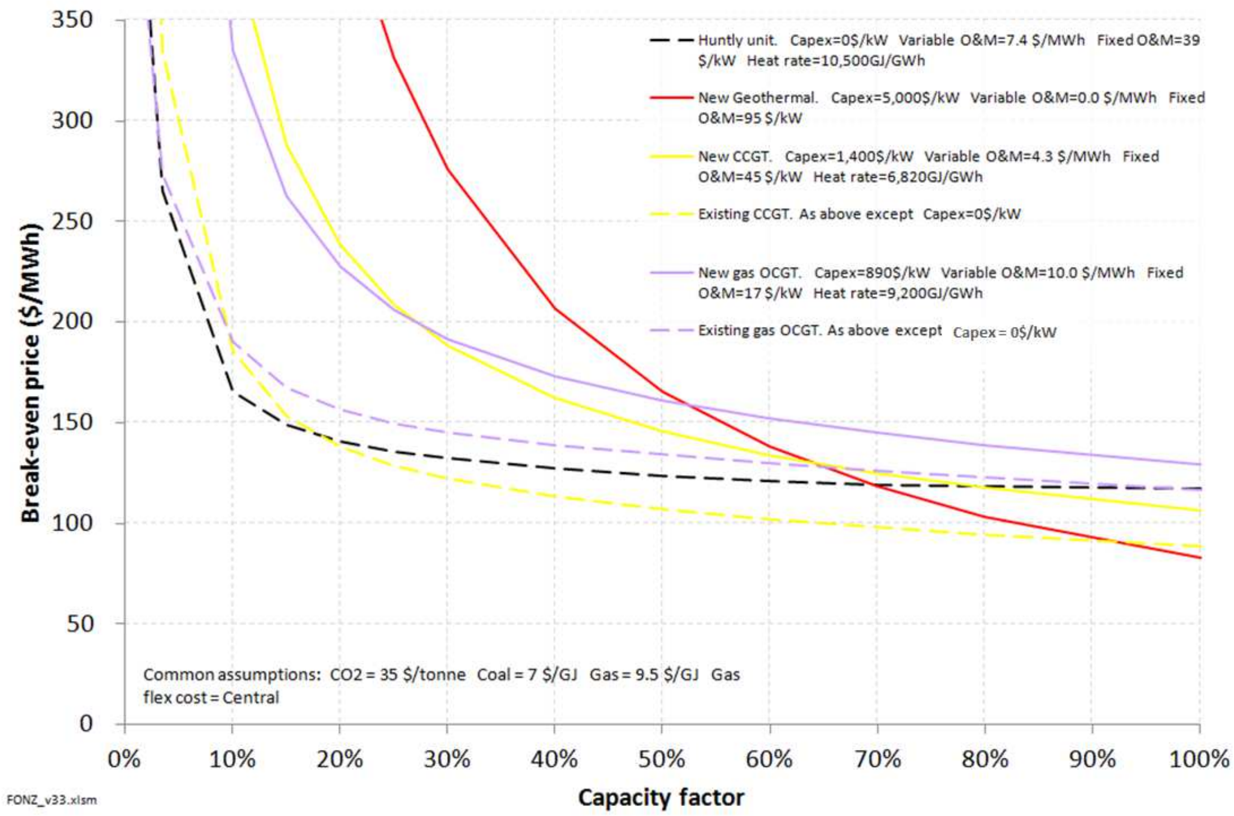
3.3.2 Peaking generation

While investment in new baseload gas-fired generation before 2020 appears to be relatively unlikely, the same is not true for gas-fired peaking generation. This is because electricity demand exhibits a degree of seasonality/peakiness that cannot be easily satisfied by building new baseload power stations. Further, to the extent that wind plant is developed, this will give rise to a need for further peaking capacity to act in wind balancing/firming role – particularly at times of peak demand.

40 If Tiwai were to suddenly cease consumption, it is likely that a significant proportion of generation from Manapouri would be unable to be exported to the broader grid. However, Transpower has indicated that such transmission constraints could be relieved within a couple of years for relatively little cost.

The capital intensity of new renewables plant means that, while they may be most cost-effective at meeting baseload duties, they become progressively more expensive for low capacity factor operations. This is illustrated in Figure 27, which also shows that the lower capital cost (in $/kW terms) of an open cycle gas turbine (OCGT) means it is likely to be more cost effective than a CCGT for low capacity factor duties.

Figure 27: Generator cost curves



Source: Concept analysis

As such, it is likely that some new peaking generation will be required during the next fifteen years. The scale of such new generation, and the extent to which it is gas-fired or diesel-fired will depend on a number of complex issues including:

- The extent of the growth in electricity demand for low-capacity factor generation, which is driven by:
  - The extent of peak demand growth, which in turn is linked to factors such as GDP, plus electricity wholesale and network market pricing design[41]

41 The move to regional coincident peak electricity transmission pricing in mid 2000s has started to reduce the rate of peak demand growth. Similar outcomes have been observed in those electricity distribution companies such as Orion which have introduced such pricing approaches.

- The extent of new wind development, which is influenced by factors such as the exchange rate, international wind market developments, and movements in the relative economics of wind and geothermal

- The economics of peaking gas-fired generation versus other peaking options, driven by:
  - The economics of Huntly (Huntly units displaced from baseload / mid-merit duties could potentially meet a growth in demand for lower capacity factor peaking duties), which is influenced by capital requirements for life extension and coal market issues
  - The costs of diesel generation
  - The wholesale cost of gas
  - The cost of providing gas swing (whether from the Ahuroa underground storage facility, field re-injection, or field swing)
  - The costs of demand-side fuel flexibility – curtailing demand at times of scarcity – and the extent to which market arrangements facilitate such outcomes

These are subject to material uncertainty, and a fairly wide range of outcomes is possible. It is not within the scope of this study to undertake detailed electricity market modelling across a very wide range of scenarios. Instead, this study makes plausible assumptions about the key variables and focusses on the sensitivity of outcomes to gas prices.

This approach is judged to be reasonable because changes in peaker investment are unlikely to have significant implications for further investment in the Vector transmission network (for the reasons discussed below), or a major effect on annual gas demand (because gas-fired peakers do not typically have high utilisation rates, unlike baseload generation).

In relation to gas pipeline investment, it has previously been the case that new power station development was likely to drive the need for additional pipeline capacity. This was because the electricity transmission system in the upper North Island was reaching capacity and it was more cost effective to expand gas pipeline capacity into the region. However, looking forward, the situation is changing, such that:

- Any new power station could incur significant gas transmission charges if its development were to give rise to the need for pipeline investment. Given that the North System pipeline has reached capacity during peak demand weeks, it is likely that a new power station in the North System would require new pipeline investment. Indeed, this is understood to have been a material detrimental factor in the economics of the proposed (but now shelved) Rodney CCGT north of Auckland.
- The electrical benefits of locating in Auckland / Northland are likely to be materially less going forward because:
  - Transmission upgrades (such as the North Island Grid Upgrade Proposal (NIGUP) into Auckland and the North Auckland and Northland (NAAN) upgrade into Northland) will significantly reduce the risk of transmission constraints into the region for the short- to medium-term;
  - The on-going change in the geographical disposition of generation versus demand is such that flows are increasingly heading from North to South even in relatively ‘mild’ dry periods, rather than the predominant northward pattern that was the norm for most of the previous decades. This is reducing the locational benefit of locating generation in the upper North Island.
  - The current method of recovering costs for common-use transmission assets does not provide a strong locational price signal for new power station investment.

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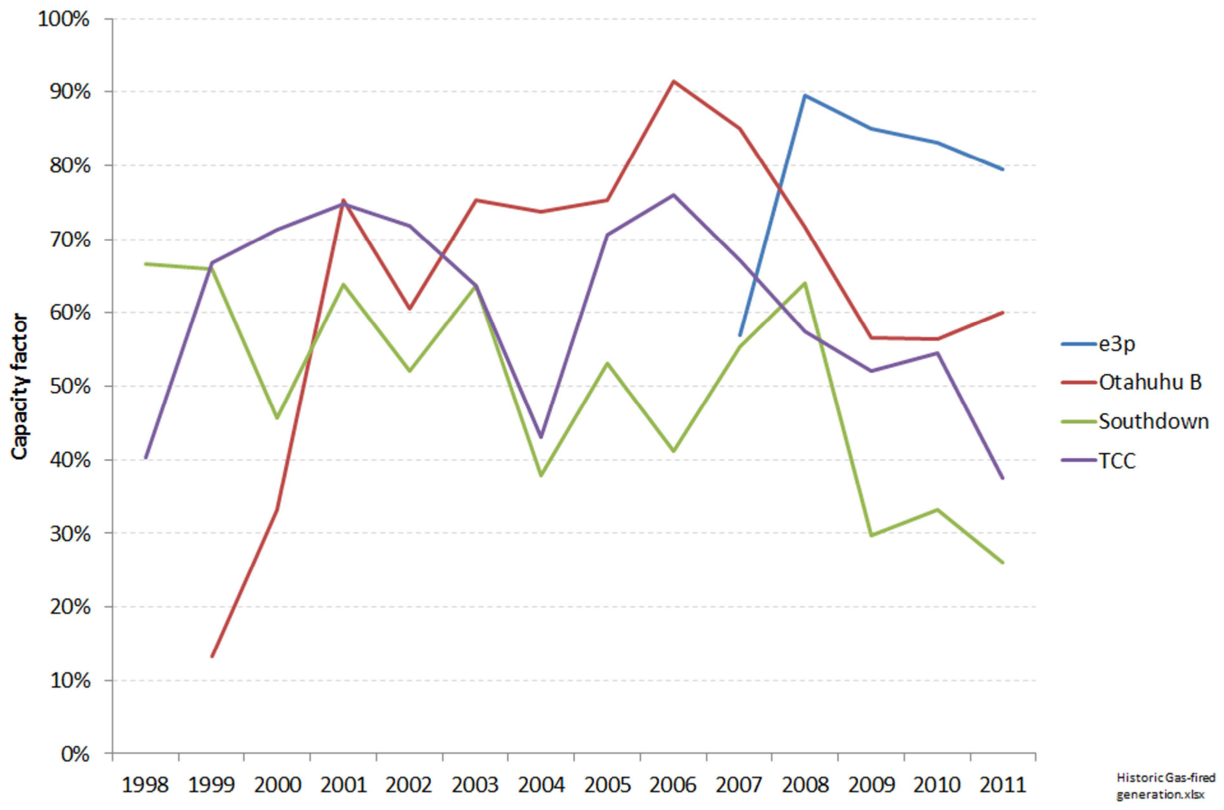
Accordingly, it appears unlikely that any new gas-fired generation (peaking or baseload) would choose to locate on the North Pipeline System, but is instead more likely to locate in Taranaki, or close to the end of the Maui pipeline in the Waikato area. Both regions have sites with good gas and electrical connection potential without requiring significant upgrades, contain brown-field development opportunities, and may have other RMA-type benefits compared to locating in the Auckland region.

These observations are consistent with the pattern of investment which has emerged in recent years (i.e. the 2 x 100MW Contact peakers, the 100MW peaker currently being developed by Todd Energy, and the further 100MW peaker proposed by Todd Energy, are all located in the Taranaki region).

3.3.3 Pattern of operation from existing plant

Historically, many of the gas-fired power stations in New Zealand have operated to relatively high capacity factors, as illustrated by Figure 28.

Figure 28: Historic capacity factors of gas-fired generation plant



Source: Concept analysis using Electricity Authority Centralised Data Set data

However, during the course of the study a number of parties have suggested that such high capacity factors were a function of the relatively high take-or-pay commitments that the generators faced in their gas supply agreements, and that once such supply agreements started to expire it would be likely that their capacity factors would fall significantly. In this respect, Contact's gas supply agreements almost completely expire by the end of 2014, although Genesis has committed to take the full output of the Kupe field which is expected to be in production at least until 2025.

To examine this issue an electricity sector model has been used to examine the extent to which demand for gas generation could vary as gas price varies. One of the key issues the model seeks to address is the fact that electricity prices vary significantly throughout the day and year, and from year-to-year, due to changing levels of demand and other factors such as changes in hydro inflows.

Thus, there may be many periods where electricity prices are so low as to make gas-fired generation uneconomic given the underlying gas price and other variable costs faced by gas-fired generators. However, such uneconomic time periods can occur very close to higher-priced time periods where it would be economic to generate. For example, prices may be low overnight, but high during the morning and evening peaks.

CCGTs face a cost associated with start-ups, as the generator will be less efficient when running from cold and incurs higher maintenance costs from wear-and-tear with start-ups[42]. Accordingly, it may not be cost-effective to incur the start-up costs to capture just a few hours of high prices.

Conversely, it may not be cost-effective to switch off a generator (and thus incur a future start-up cost) just to avoid a few periods of relatively low prices. Instead, a generator would turn down output to its minimum stable generation level – which for a CCGT can still be a significant proportion of its output.

A model which takes broad account of these effects was used to estimate optimal operating patterns for a given sequence of electricity prices, and a particular set of gas prices and gas-fired generator characteristics. This model used a half-hourly time series of historical electricity prices from 1 January 2007 through to 31 March 2012 (92,016 data points in all). This time period was considered to be suitably long to capture both dry and wet periods, as well as periods of short term capacity stress.

The model used the historic price data as a base, but allows the 'shape' of prices to be altered to obtain an assumed time-weighted average price, and/or skew the distribution of prices to give a 'peakier' distribution if desired.

Against this price series, the model estimated the optimal operating pattern for a gas-fired generator given the following parameters:

- Gas price ($/MWh)
  - Baseload wholesale price; and
  - Swing premium for lower capacity factor operations
- CO2 price ($/tCO2)
- Heat rate (GJ/MWh)
- Variable O&M costs ($/MWh)
- Plant start-up costs ($k)
- Minimum & maximum generation levels (MW)

The two types of gas-fired generator considered were a CCGT and an OCGT. Two of the key differences between the two types of plant were the heat rates (7.1 and 10 GJ/MWh, respectively), and the minimum generation levels (58% and 20% of maximum generation levels, respectively).

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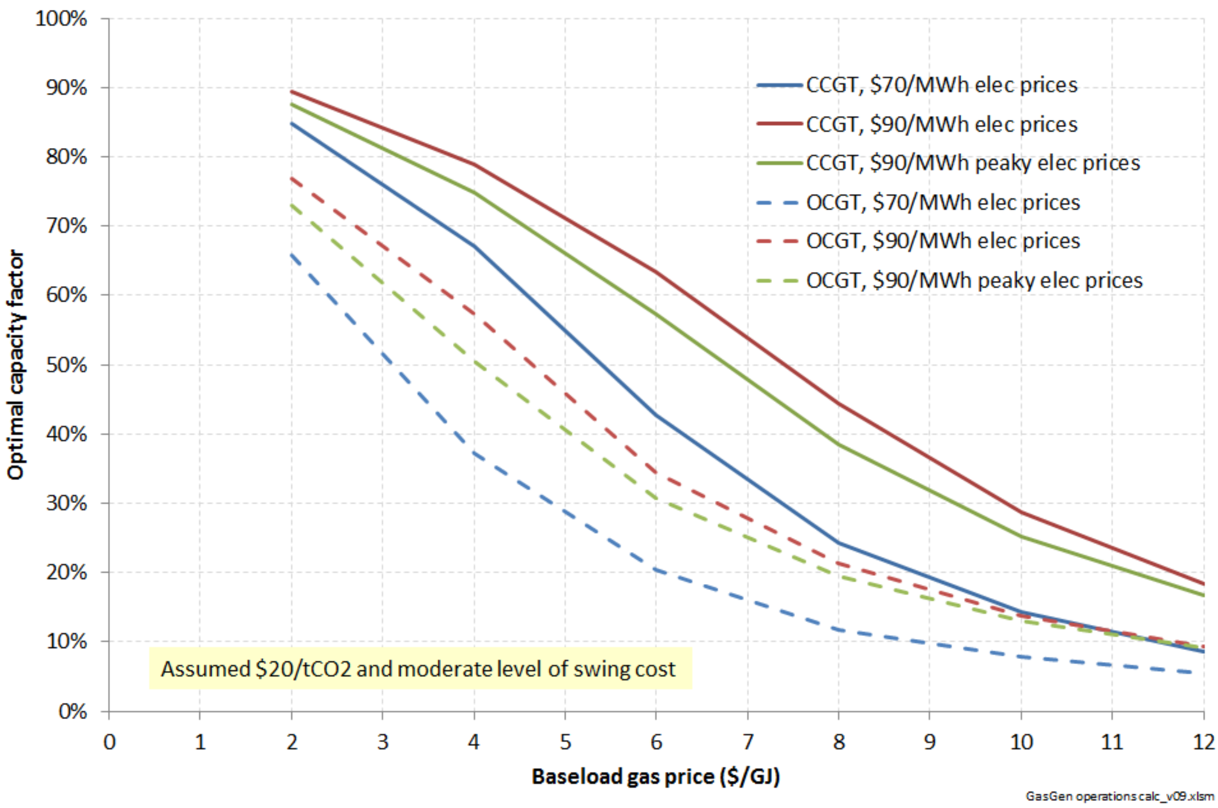
42 Generators face such wear-and-tear costs through their long-term maintenance agreements (LTMAs) with the manufacturers of the turbines. Such LTMAs typically specify the maintenance penalty cost associated with each start-up.

This model was used to estimate 'optimal' running patterns and consequent gas demand, assuming the gas station owner had perfect foresight. The model was then run repeatedly for different combinations of electricity price, gas price, and plant type (CCGT or OCGT)[43].

The results of this optimisation for a $20/tCO2 price and moderate swing costs are shown in Figure 29 below.

Figure 29: Simulation of different optimal gas-fired generator operating patterns in response to varying gas prices



Source: Concept analysis

Based on this model of gas plant operation, electricity generators demonstrate a significant downward-sloping demand curve in relation to gas price.

OCGTs operate at lower capacity factors to CCGTs for a given state of the world, principally due to the fact that they are more flexible – in particular having a lower minimum generation and thus being able to avoid generating as much during unprofitable periods.

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43 The model was also run with many different start-up costs given the uncertainty around start-up costs for the different plant types and situations. However, while the impact of varying start-up costs materially altered the number of times the plant started and stopped, it was found to have relatively second-order impact in relation to overall capacity factors compared with the impact of varying electricity and gas prices, and plant types. Accordingly, the analysis presented here is based on a central estimate of start-up costs for each plant type.

At first sight, the CCGTs appear to operate at lower capacity factors than may intuitively have been expected for low gas price futures. Such an operating regime may not have been possible in previous years because the generators faced relatively high levels of take-or-pay volumes in their gas supply contracts with relatively low swing ability. Thus, in order to have sufficient gas to power the generators during the high value winter periods, the generators also had to commit to take gas during the low value summer periods. As such, their operating patterns were sub-optimal compared to the cost of gas (although probably still profitable).

The gas storage facility at Ahuroa is expected to significantly alter this dynamic. Thus, generators can commit to a lower annual quantity of gas which can be stored during the summer in order to be used during the winter. This gives generators a greater ability to avoid generating during low value periods and only target the high value periods. It is likely that the gas-fired generation fleet owned by Contact will thus be better able to operate in such a way, particularly after its existing gas supply agreements finish at the end of 2014.

Genesis, on the other hand, has a long term contract to purchase all of the natural gas produced by the Kupe field (of which it is also a part owner). For this reason, it appears likely that the e3p CCGT will continue to operate at higher capacity factors during this period[44] than Contact's CCGTs.

3.3.4 Overall projections of gas demand from the power generation sector

The analytical framework described above has been used to develop projections of gas demand for power generation for the three gas price scenarios discussed earlier. The projections include gas demand from existing plant and for new stations (where relevant). As discussed earlier, it is important to note that the projections are sensitive to assumptions about factors outside of the gas sector (such as carbon prices). The results are summarised in Figure 30.

In the low price scenario gas demand grows progressively, reflecting the strong competitive position of gas in the baseload and peaking markets. This leads to high rates of gas usage in existing plants, and the development of new 100MW peaking plants in 2015, 2022 and 2025, and a new 400MW baseload plant in 2019.

In the medium price scenario gas demand remains around current levels, although there is a gradual change towards increasing use in peaking generation and reduced baseload demand. The increasing demand for peaking generation also requires some further investment in new peaking capacity with 100MW plants developed in 2017 and 2024 respectively.

In the high price scenario, gas demand progressively declines, largely as a result of baseload generation becoming less competitive with renewables and coal-fired generation. However, gas demand for peaking stations is less affected by higher gas costs. Overall demand for gas for power generation declines to around 50% of existing levels, and no new gas-fired power generation plant is developed in the forecast period[45].

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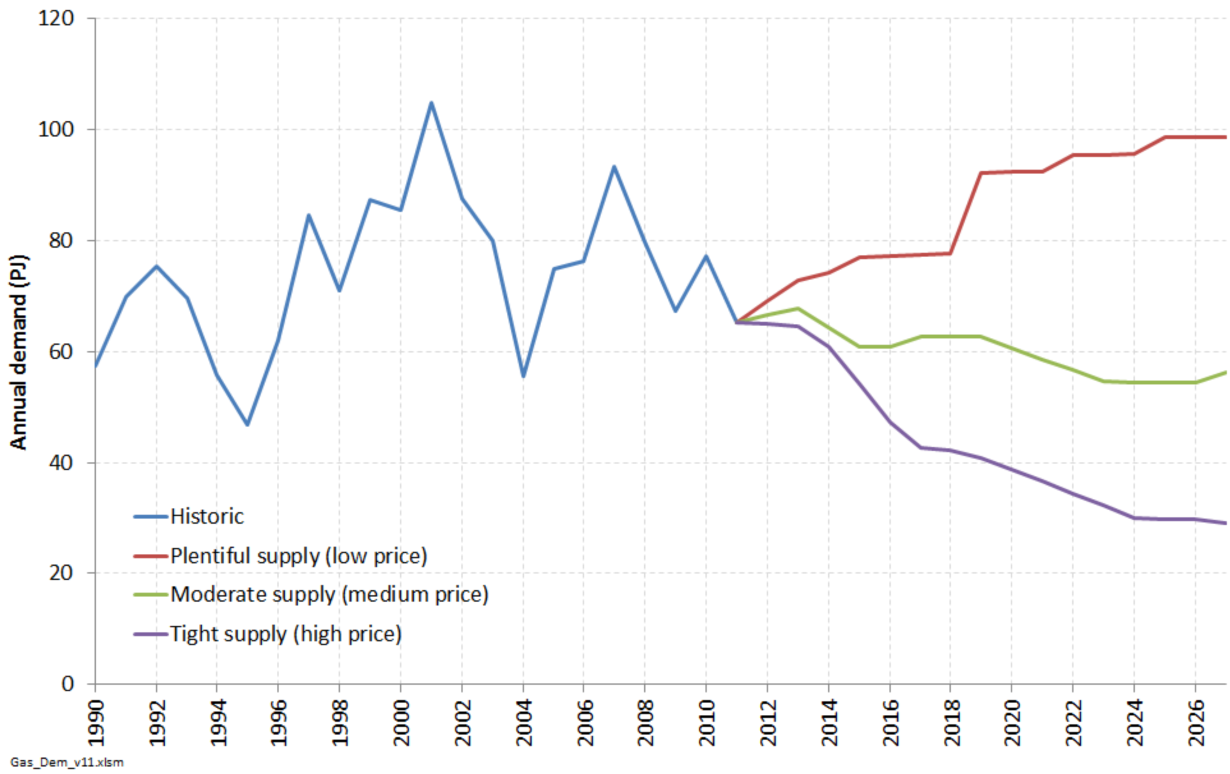
44 Noting also that it may have a slight cost advantage over other existing CCGTs because of its location on the Maui pipeline, which avoids Vector transmission costs, and its slightly higher efficiency.

45 Diesel peakers are assumed to be developed to meet the needs for new peaking capacity. In addition, in this scenario, Huntly units are not retired to the same extent, thereby reducing the need for additional peaking capacity to be built.

Figure 30: Projected power generation gas demand for the different price scenarios



Source: Concept estimates

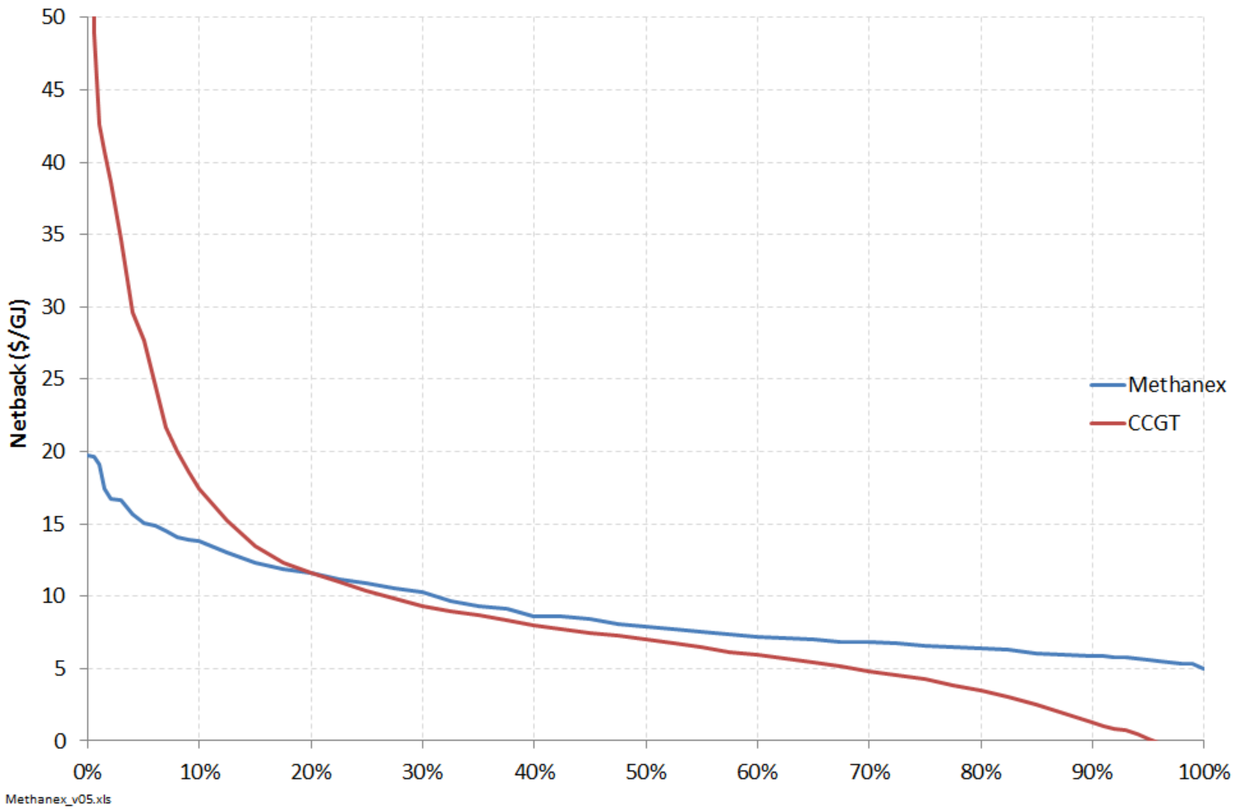
Even in the high gas price scenario, a reasonable amount of gas is consumed for power generation (approximately 30 PJ in 2026), whereas Figure 22 previously suggested that in the same scenario the petrochemical sector would almost completely exit the New Zealand market.

The reason for this difference is the different nature of the demand for electricity and methanol. As shown in Figure 20, methanol prices have fluctuated over the past decade, with prices ranging from $200/tonne through to $750/tonne. However, electricity prices exhibit far greater volatility, with prices ranging from $0/MWh through to many thousands of dollars per MWh. This is because of the unusual nature of electricity, in that it cannot be economically stored in large quantities and yet demand varies significantly throughout the day and year. This gives rise to a relatively few periods of time where there is significant supply capacity shortage characterised by extreme prices, while the rest of the time there is general supply surplus characterised by relatively low prices.

This difference in price distributions is illustrated in Figure 31, which shows the inferred gas net-back values[46] for power generation and methanol production.

46 The gas net-back price is calculated as the price of the product (electricity or methanol) minus any *non-fuel* variable operating costs and factored by the plant efficiency (i.e. how many GJ of gas are required to make a tonne of methanol or a MWh of electricity).

Figure 31: Duration curves of gas net-backs for methanol production and electricity generation[47]



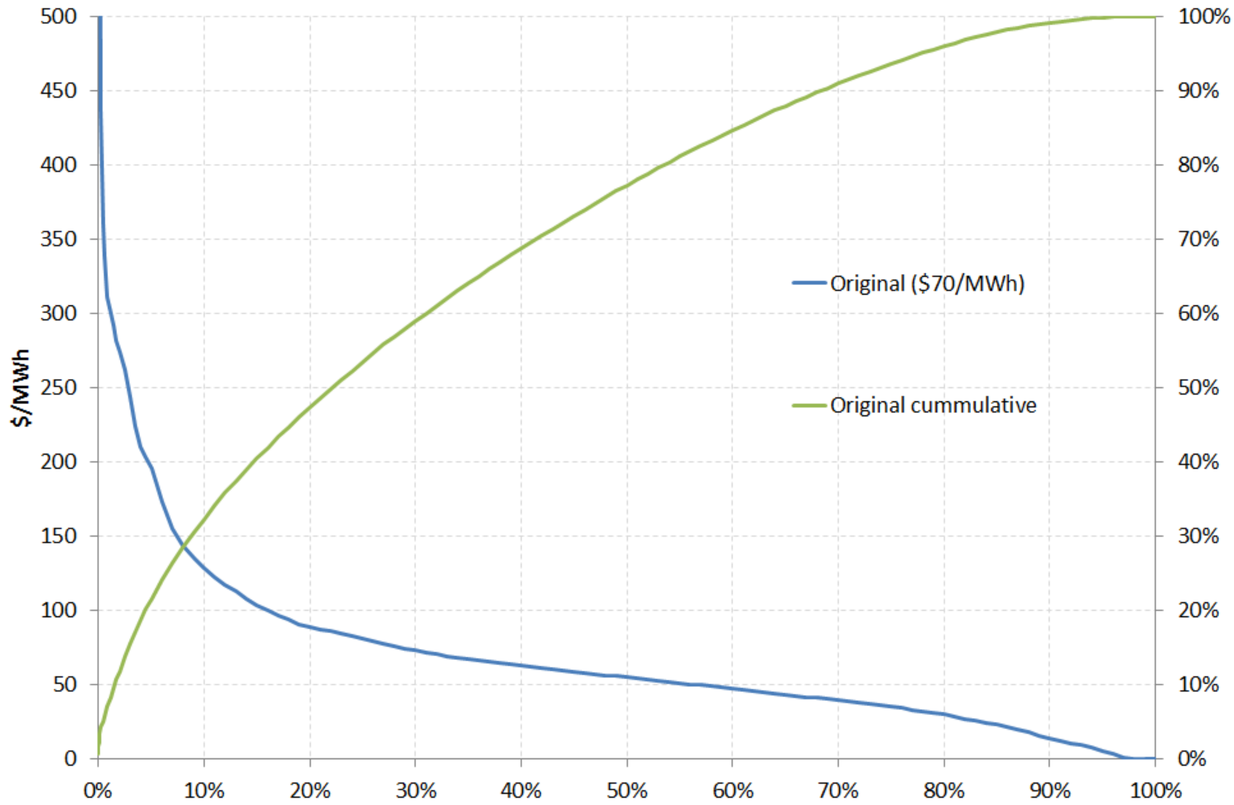
Source: Concept analysis

Based on historic prices, gas is more valuable for methanol production than power generation for the majority of time. However, for the top 20% of times, gas is more valuable for electricity generation. Further, the average value for power generation is higher than the average value for methanol production.

Accordingly, if gas prices were to rise to the $12/GJ value in the high price scenario, they would be significantly above the mean gas netback value for methanol (estimated to be approx. $8/GJ), and it is likely that methanol production would cease. However, there would be still a reasonable percentage of time when the value of electricity is high-enough to justify operating a gas-fired generator – even with $12/GJ gas. Indeed, the asymmetry of the electricity price duration curve is such that a reasonable proportion of the value of electricity would be captured from operating for only 20% of the time. As shown in Figure 32 (which depicts the price duration curve and cumulative value curve for the period Jan-07 to Mar-12), approximately 47% of the value of electricity prices comes from 20% of the time periods.

47 The methanol price duration curve is based on monthly Asian methanol prices posted by Methanex from Sep-02 to Jul-12. The electricity price duration curve is based on half-hourly Otahuhu prices from Jan-07 to Mar-12.

Figure 32: Historic electricity price duration curve and associated cumulative value curve



Source: Concept analysis using Electricity Authority Centralised Data Set data

Thus in the high cost scenario, gas-fired generation would be expected to operate predominantly in a relatively low capacity factor seasonal / peaking / dry-year firming role, with a significantly greater level of renewable generation developed to displace such gas-fired generation from baseload operations.

3.4 Industrial, commercial and residential – annual demand

One of the principal purposes of this study is to develop projections of demand on the Vector transmission network to inform consideration of pipeline investment and pricing / access arrangements. In undertaking the analysis of demand on the Vector transmission network, the Vector network has been split into regional 'systems' as shown in Figure 33.

Figure 33: Illustration of regional definitions on Vector transmission system[48]

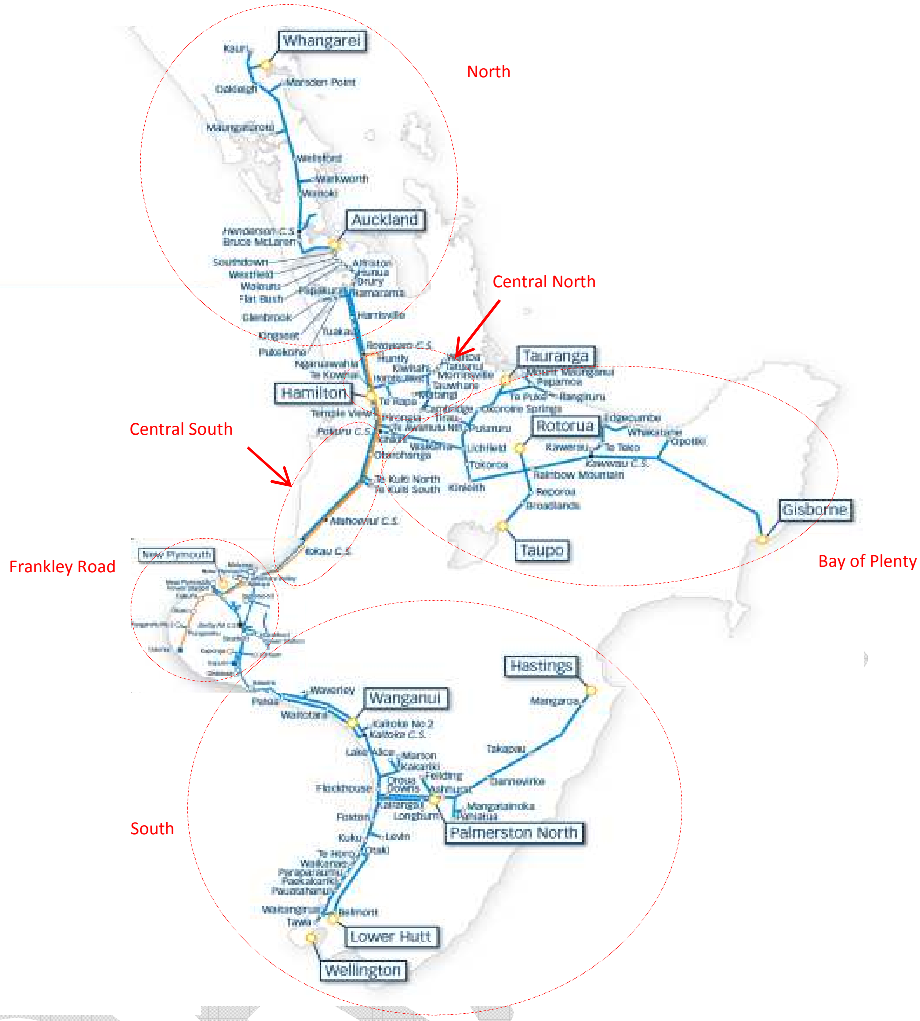


Figure 34 and Figure 35 show how demand for gas off the different Vector transmission systems has changed over the past ten years.

48 The Vector transmission system is represented by the blue lines, whereas the Maui pipeline (running from Taranaki through to Huntly) is represented by the yellow line

Figure 34: Breakdown of annual consumption across Vector transmission systems

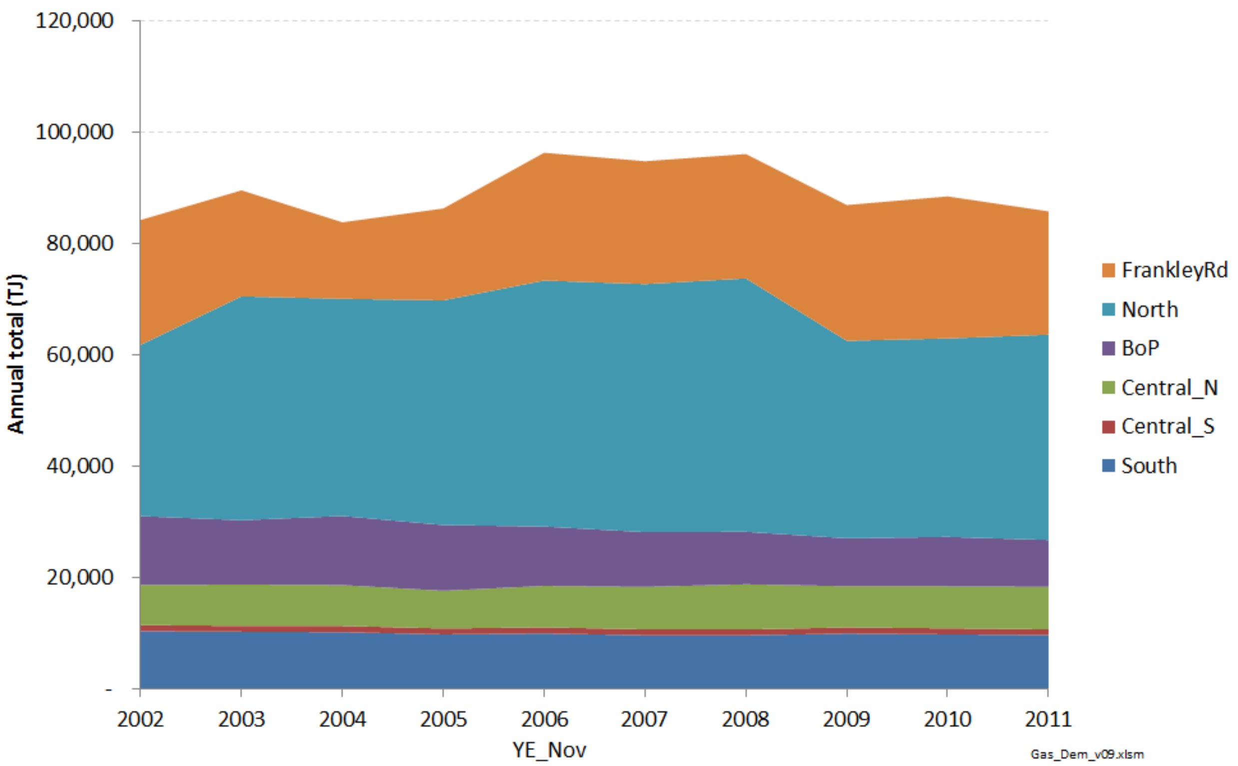
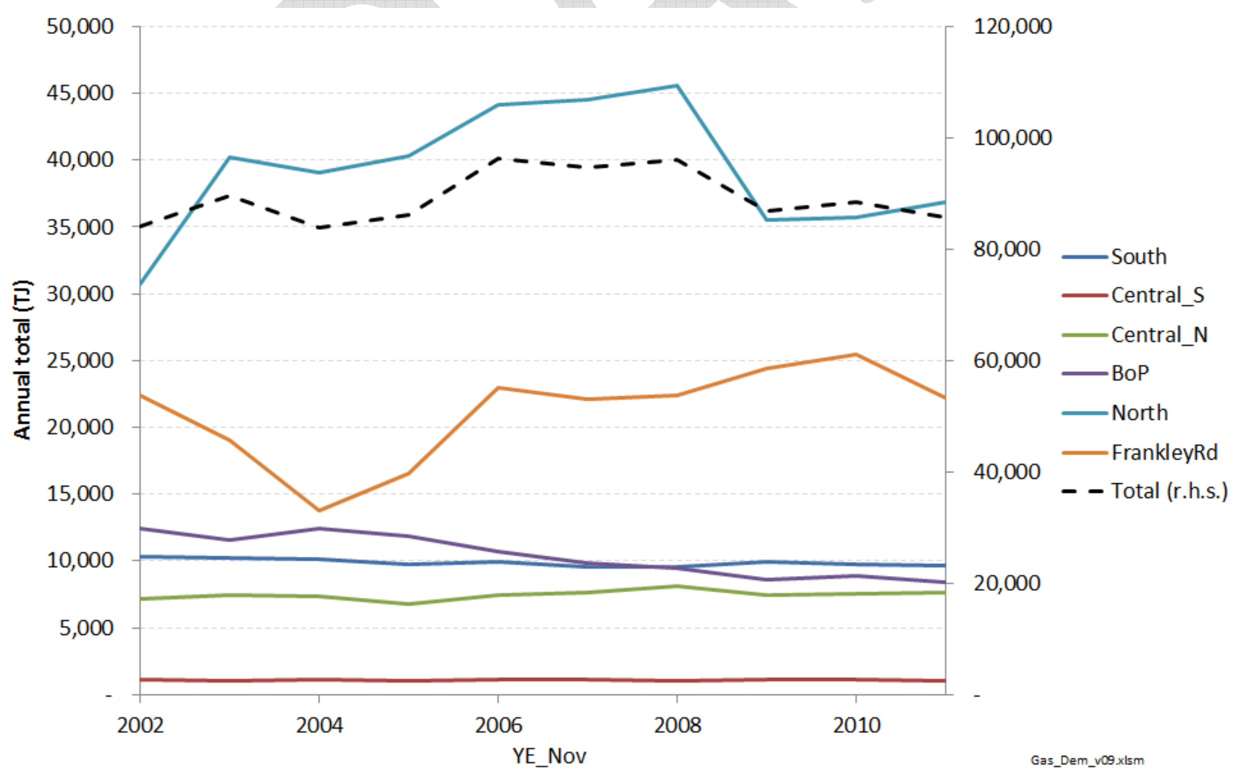


Figure 35: Annual gas demand off the Vector transmission network



There has been significant variation in demand on some of the systems.

In the pipeline investment and pricing context, the region of principal interest is the North system. This is because recent levels of gas demand have reached the limits of that pipeline's capacity, whereas no significant capacity constraints are understood to be in prospect for other systems in the short- to medium-term.

As such, much of the discussion and analysis in this report focuses on the North system, although the analysis framework and modelling toolset covers all the Vector systems.

In order to better understand what is behind the movements in gas demand, all the gates on the Vector transmission system have been categorised according to the type of customer. Only those gates with 'direct connect' customers (i.e. a single large industrial customer) have been categorised into a specific industrial sector (for example Dairy, Steel, Paper[49] etc.). For the gates which feed distribution networks, demand has been split between time-of-use (ToU) and Non-time-of-use (Non) customers. ToU customers are industrial customers with demands typically greater than 10TJ per annum, whereas Non-ToU customers are predominantly mass-market small customers (both residential and small-business). Figure 36 below shows such information.

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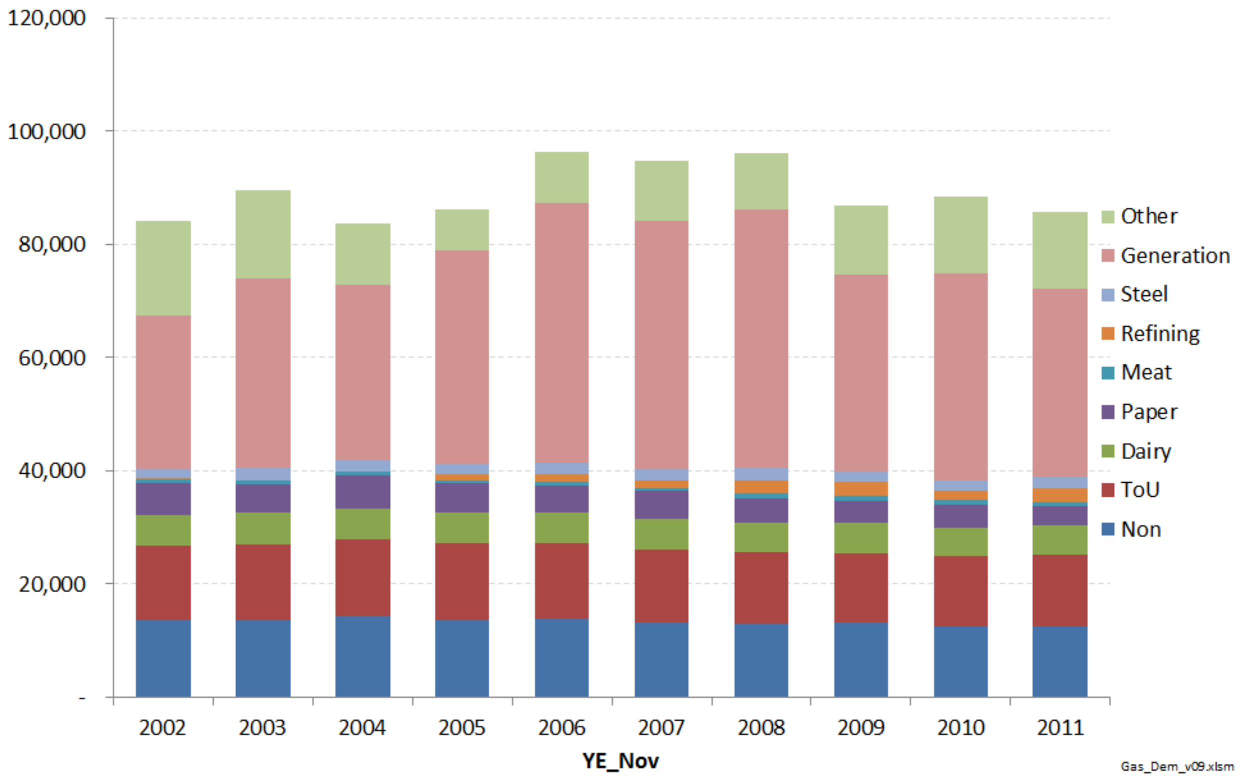
49 The 'Paper' sector covers all pulp, paper and wood processing.

Figure 36: Historic consumption split by customer use across Vector transmission system[50]



Power generation is not only the largest use of gas transported over the Vector transmission network, but it is also the use which exhibits the greatest year-to-year volatility. This is even more the case when just considering the Vector North system as shown in Figure 37 below.

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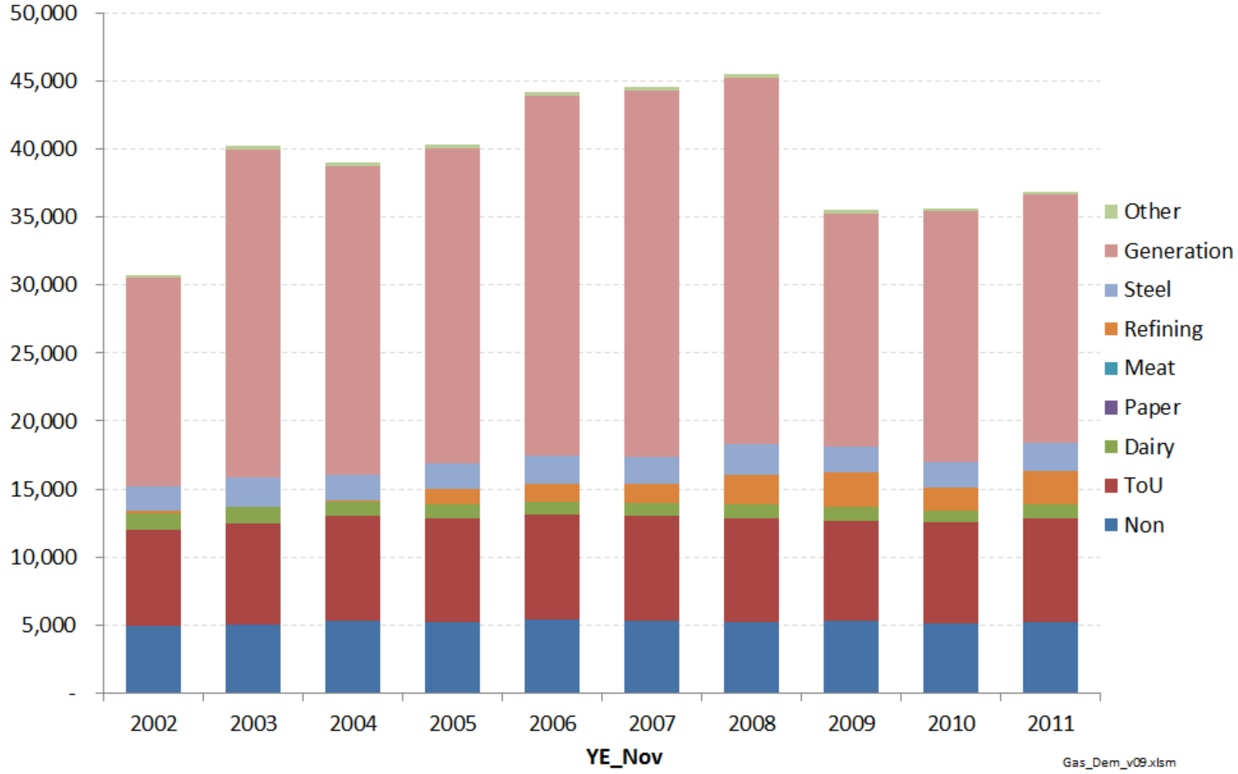
50 The 'Other' category covers gates which have been classed by Vector as "petrochemicals" and "other" industrial sectors. Approximately 90% of 'Other' demand is for the Frankley Rd system, principally relating to petrochemicals demand.

It should also be noted that cogeneration on direct connect sites has generally been classified as belonging to the sector associated with that site. (For example Dairy, Steel, Paper, etc.) – the main exception being the Te Rapa cogeneration site. This contrasts with the MBIE Energy Data File data shown in Figure 4 and Figure 17 earlier, where much of this cogeneration has been classified as power generation.

Figure 37: Historic annual demand on the Vector North transmission system (TJ)



With the generation and 'other' sectors excluded, Figure 38 better illustrates the relative change in consumption for the other main categories.

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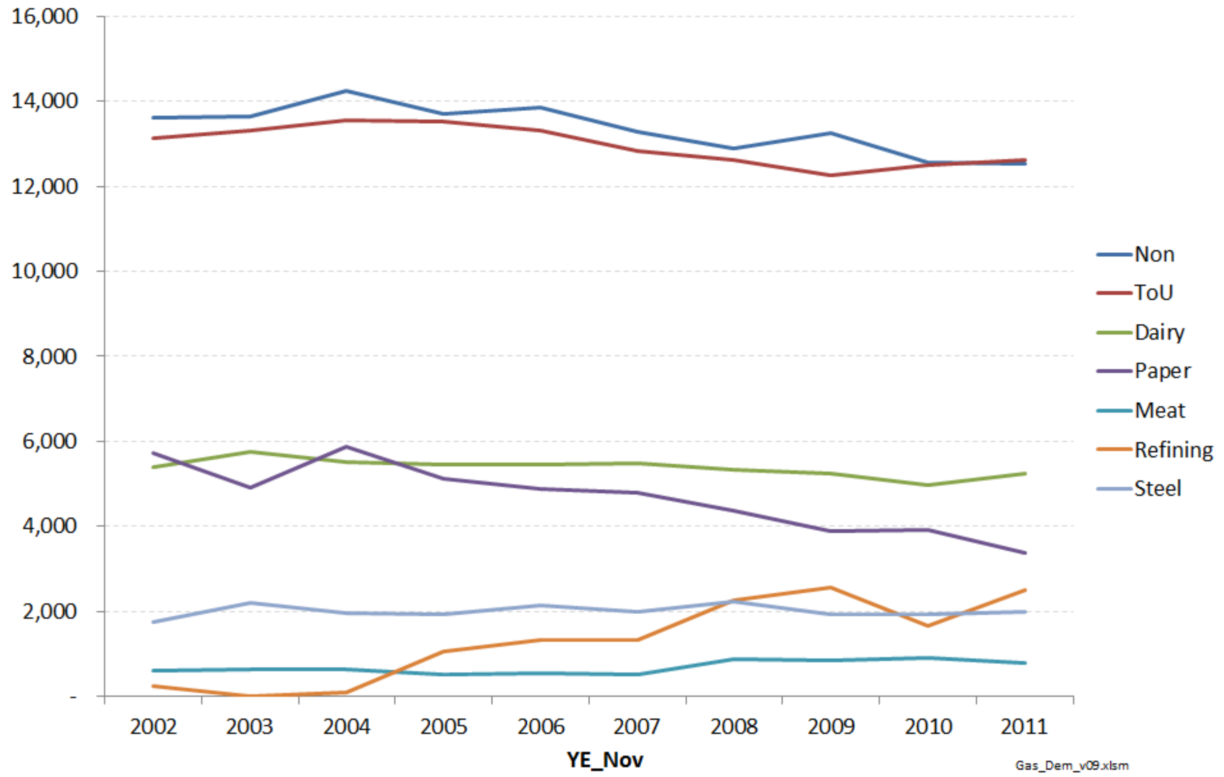
Figure 38: Historic annual gas demand on the Vector transmission system by sector, excluding the power generation and 'other' sectors (TJ)



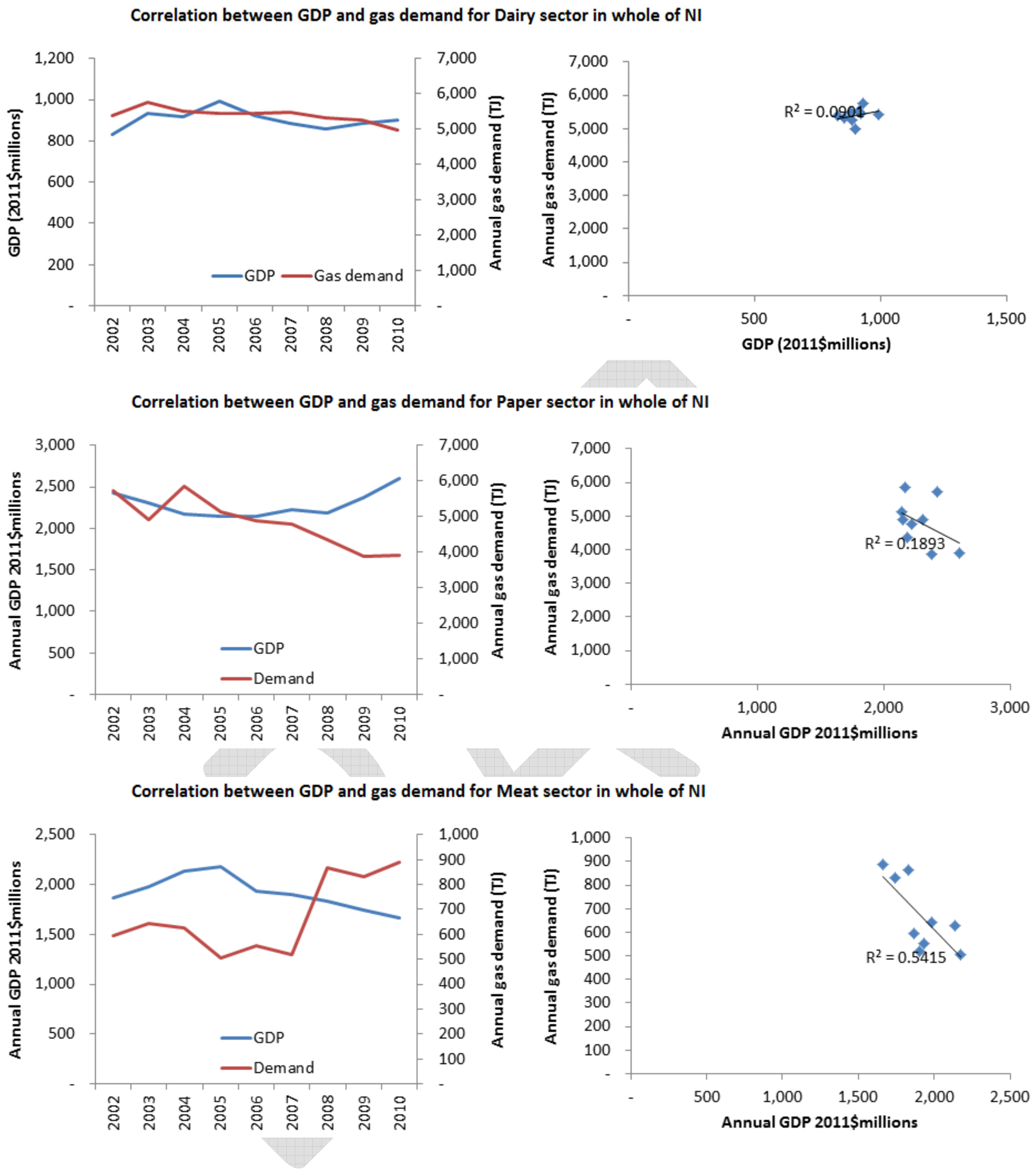
Most sectors have experienced some gradual decline or static growth. Only the refining sector (which is comprised solely of the NZ Refining Co refinery at Marsden Point) has experienced significant growth.

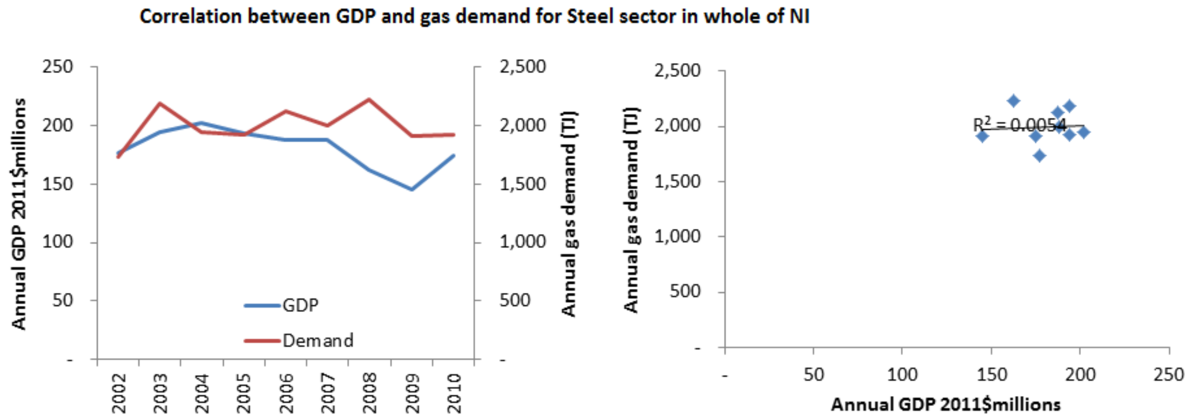
In seeking to understand what has driven changes in demand (with a view to developing a framework that could be used to project possible demand futures), some initial analysis was undertaken looking at factors such as GDP and population, given that these are two key drivers of the demand for energy services. Accordingly regional and sectoral data on both factors were sourced from Berl Economics and Statistics New Zealand, respectively.

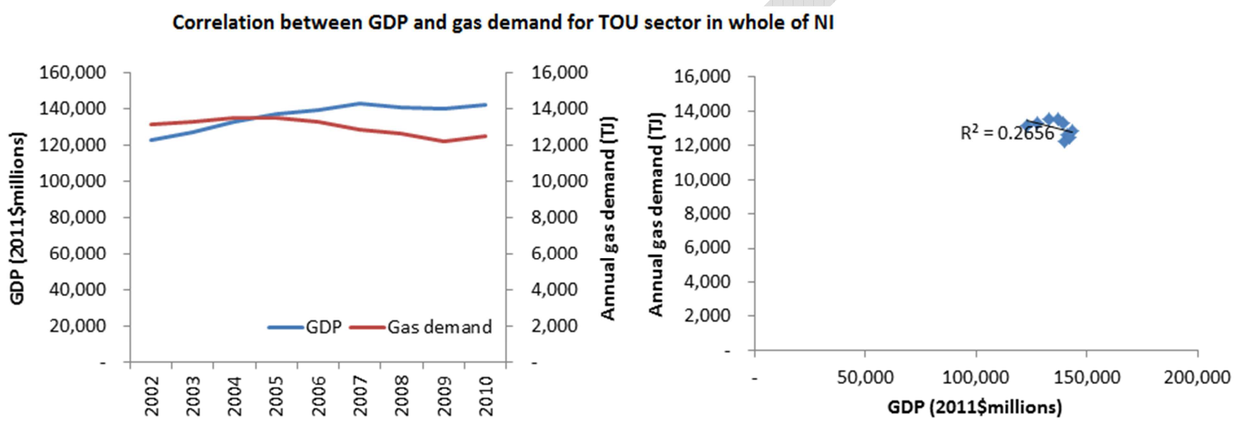
However, as the following charts illustrate, no correlation of any significance could be identified which could be used as a basis for developing future projections.

The first set of charts grouped under the heading of Figure 39 shows GDP and gas demand for the different demand sectors on a whole of North Island basis. In addition to the main industry sectors of Dairy, Paper, Meat, etc, the final chart in this series looks at combined GDP for all other industry sectors and compares it with ToU demand.

Figure 39: Correlations between GDP and gas demand for different sectors for whole of NI





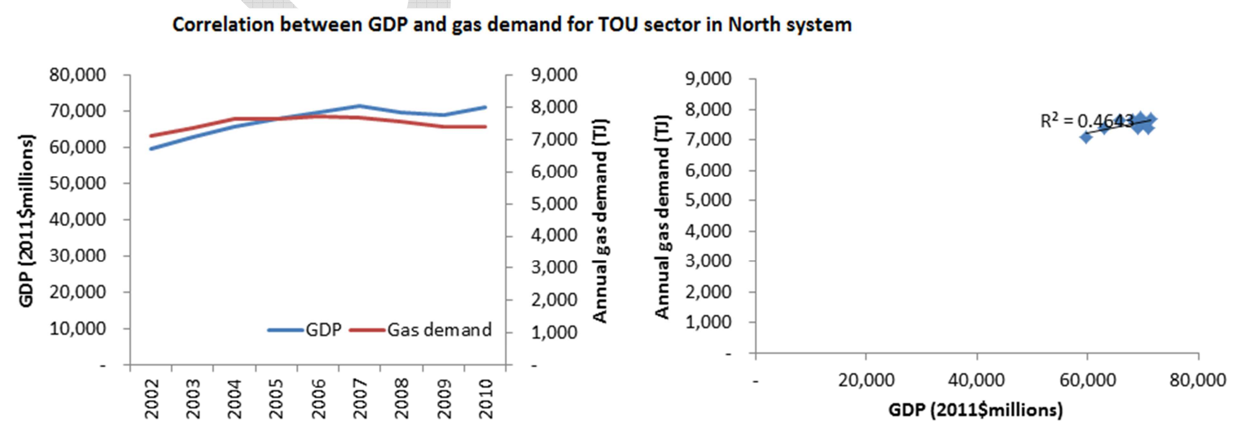


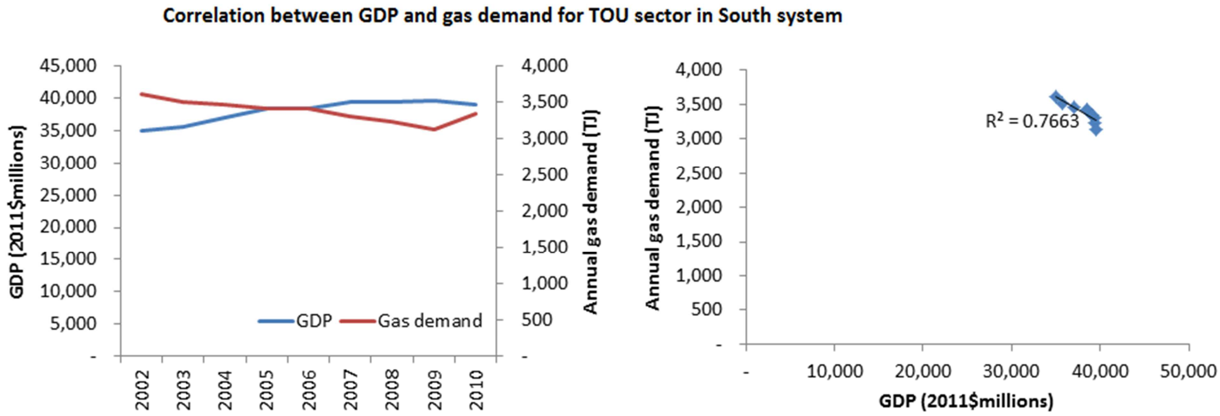
In most cases there is little or no correlation, or sometimes an apparent *negative* correlation between economic activity and gas demand.

When the data is considered on a regional basis the picture is similarly confused. For example, the following two charts in Figure 40 show the correlation between other-industry GDP and TOU gas demand for the North System and the South system.

For the North System there appears to be a reasonable positive correlation. However, for the South System there appears to be an even stronger *negative* correlation.

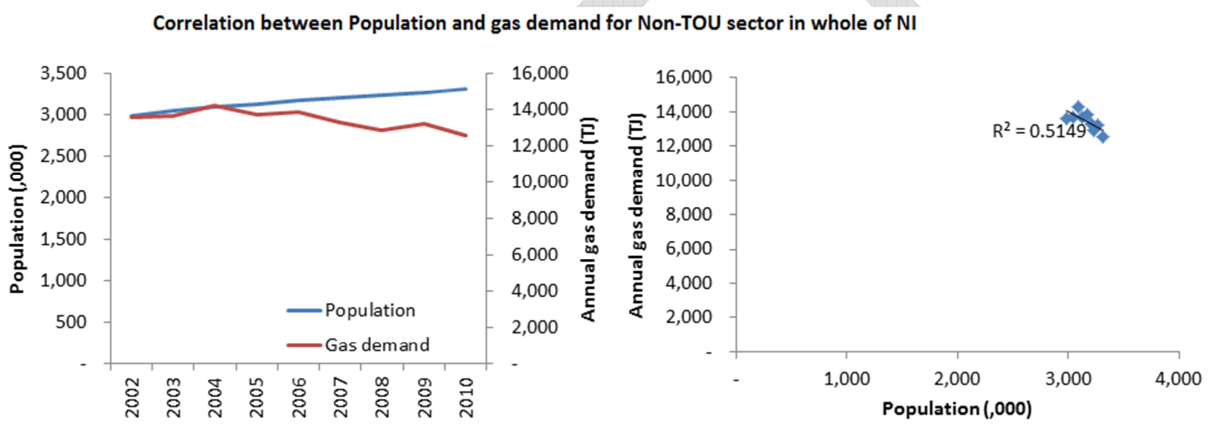
Figure 40: Correlation between other-industry GDP and TOU gas demand on a regional basis

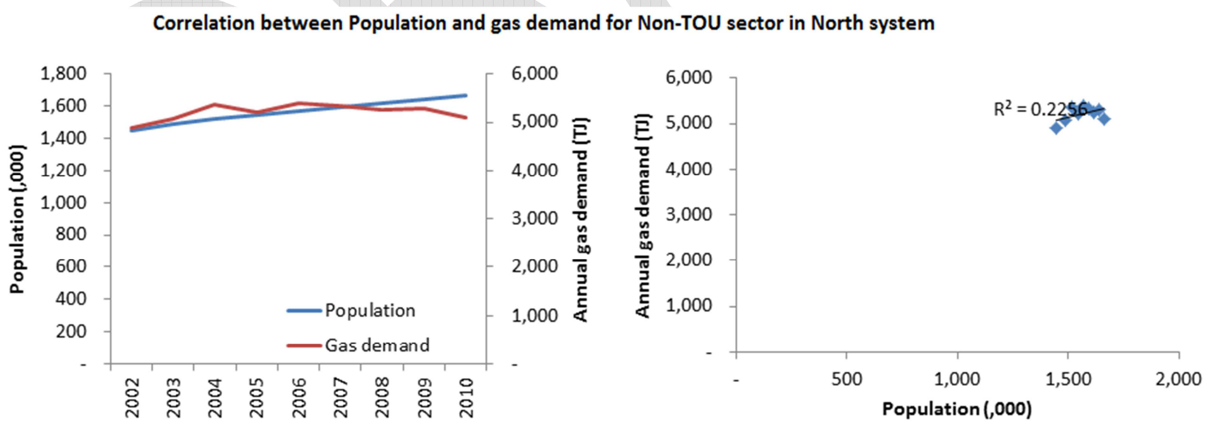


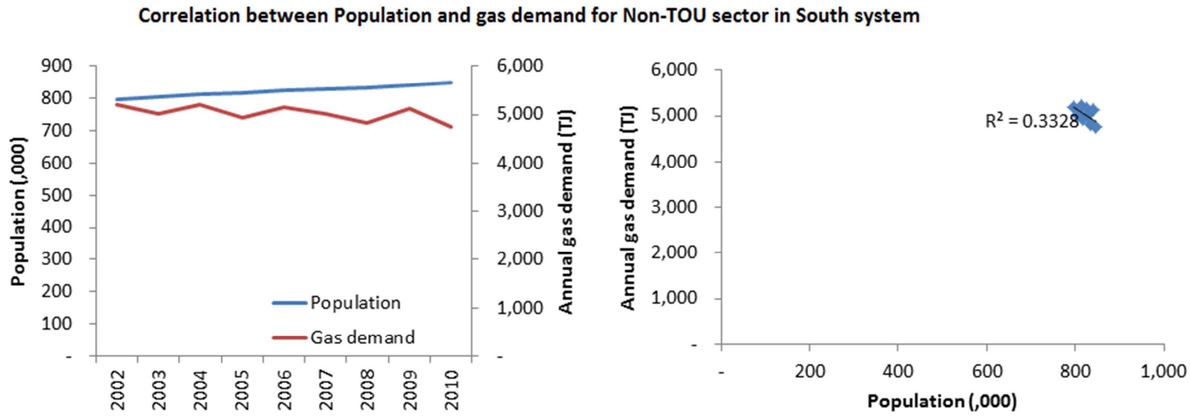


Nor does there appear to be a correlation between population and gas demand for the Non-TOU sector as illustrated by the charts grouped under Figure 41 below.

Figure 41: Correlation between population and gas demand for Non-TOU sector







In addition to suffering from only having eight years' worth of data (which is really too little to do this type of statistical analysis), the likely explanation for this apparent lack of correlation between gas demand and GDP and population is because, for most uses, gas is readily substitutable with other fuels. This substitutability probably explains much of the apparent negative correlations observed above. For example, it is understood the Paper sector has been progressively switching away from using fossil fuels as the main energy source to burning on-site biomass, plus in some cases using geothermal resources that happen to be located at the sites. In the meat sector, on the other hand, there has been some switching away from coal to gas during a time when GDP for the sector was gradually declining.

And in the mass-market sector, it is understood that gas has been losing market share to electricity for space heating, as heat pumps have gained market share over the last decade.

This substitutability contrasts with electricity demand where, for a large proportion of its uses, it is not readily substitutable with another fuel (for example in lighting, appliances, etc.). As such, electricity demand exhibits a much greater correlation with factors such as population and GDP.

Because of the scope for substitution, the demand for gas is not just a function of the demand for energy services, but is also a function of the *relative cost* of gas versus other fuel options for meeting such energy services. This relative cost is a function of a number of factors, including:

- Wholesale fuel prices (gas, coal, diesel, LPG, biomass and electricity)
- Fuel transport prices (including network costs for gas and electricity)
- CO2 costs and CO2 intensities of the different fuels
- End-use appliance / equipment characteristics
  - capital costs
  - operating costs
  - operating efficiencies

Therefore, in order to project gas demand, it would also be necessary to take account of the other factors which influence the relative price of gas versus other fuel options.

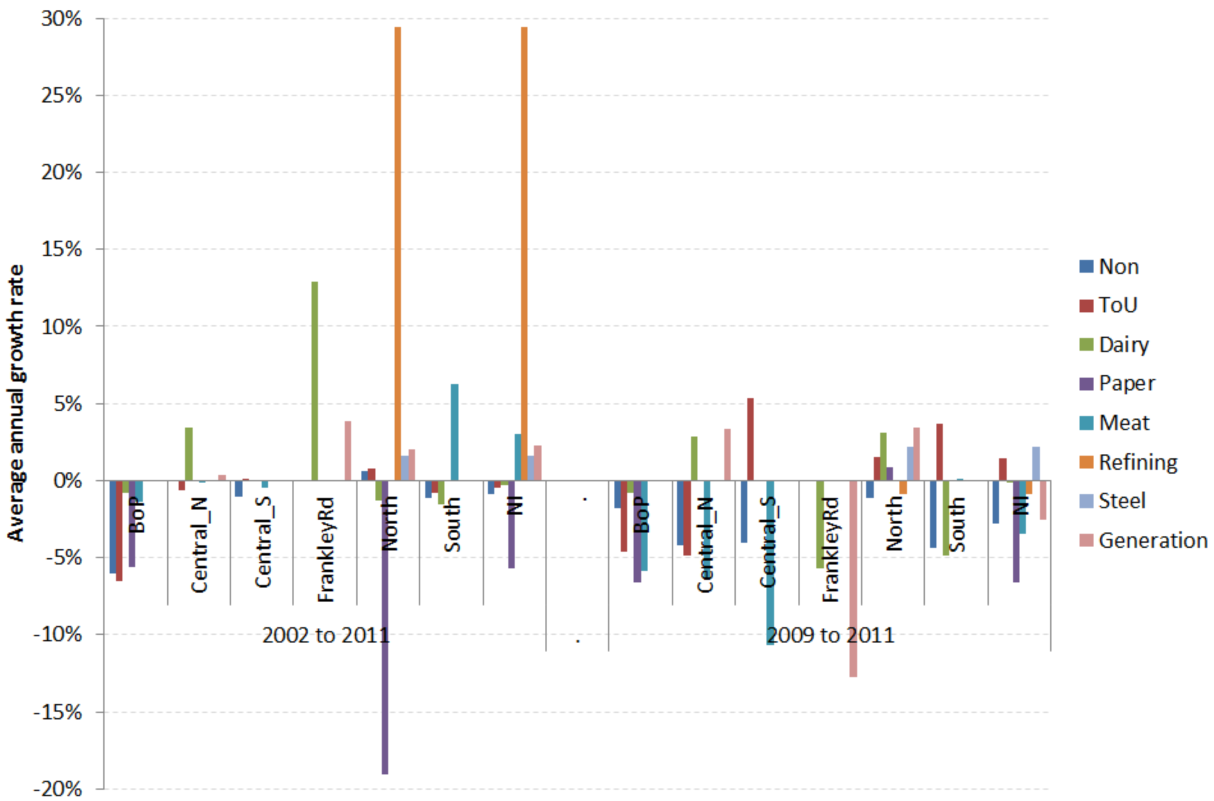
Given the many different 'moving parts' driving gas demand, many with significant uncertainties, it would be extremely challenging to try and explicitly model possible demand growth based on projections of factors such as GDP, population, fuel prices, CO2 prices and the like.

In particular, trying to develop a statistical model which examined historical data series to infer the relationship between the combinations of all the above such factors and gas demand would face significant challenges, including:

- The data series is likely to be too short (there is only ten years' worth of reliable gas data) to develop any correlations of any real significance – in particular because it is likely that some relative cost states of the world that may occur in the future haven't been experienced in the past (for example due to some technologies rapidly changing their costs or efficiencies, or CO2 / fuel prices that haven't been experienced yet)
- There is limited data for many aspects of the factors which make up the relative cost equation

The challenge in trying to project growth rates for different sectors on a regional basis is highlighted by considering historic data as illustrated by the table below.

Figure 42: Historic annualised gas demand growth rates for different sectors and different regions



There have been significant variations in growth rates across different periods, and across different Systems for the same types of demand. It would not be feasible to develop a statistical model which could reliably forecast such changes.

Accordingly, this report takes the approach of developing gas demand projections informed by high-level analysis of the economics of the main uses for gas relative to the main competing fuels / technologies.

As an initial step, analysis of different types of energy services was undertaken using EECA's energy[51] end-use database[52]. Figure 43, shows that gas usage is dominated by four end uses:

- Intermediate process heat (i.e. for temperatures between 100°C and 300°C)
- Space heating;
- Water heating (i.e. for temperatures < 100°C); and
- High temperature process heat (i.e. for temperatures > 300°C)

Figure 43: Breakdown of energy gas usage by end use (for North Island only) for industrial, commercial and residential users

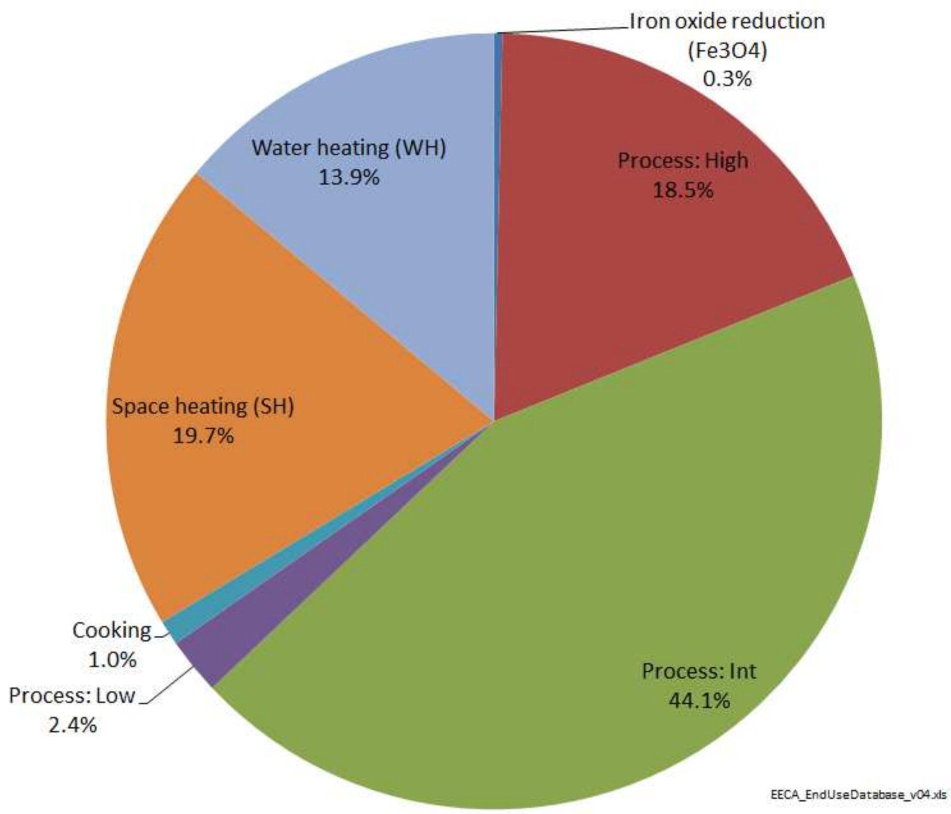


Figure 44 further shows that, apart from high temperature process heat, many other fuels are also used to provide the energy services for which gas is used. This suggests that there is the potential for a high degree of substitutability between gas and these other fuels for these uses (other than high-temperature process heat[53]).

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51 i.e. gas used as a feedstock or for power generation is not included in this database.

52 This database is available on-line here: http://enduse.eeca.govt.nz/

53 It is also understood that there are more process-specific considerations which limit the potential for fuel substitution for the delivery of high-temperature process heat.

Figure 44: North-island energy end-uses split by fuel (for industrial, commercial and residential)[54]

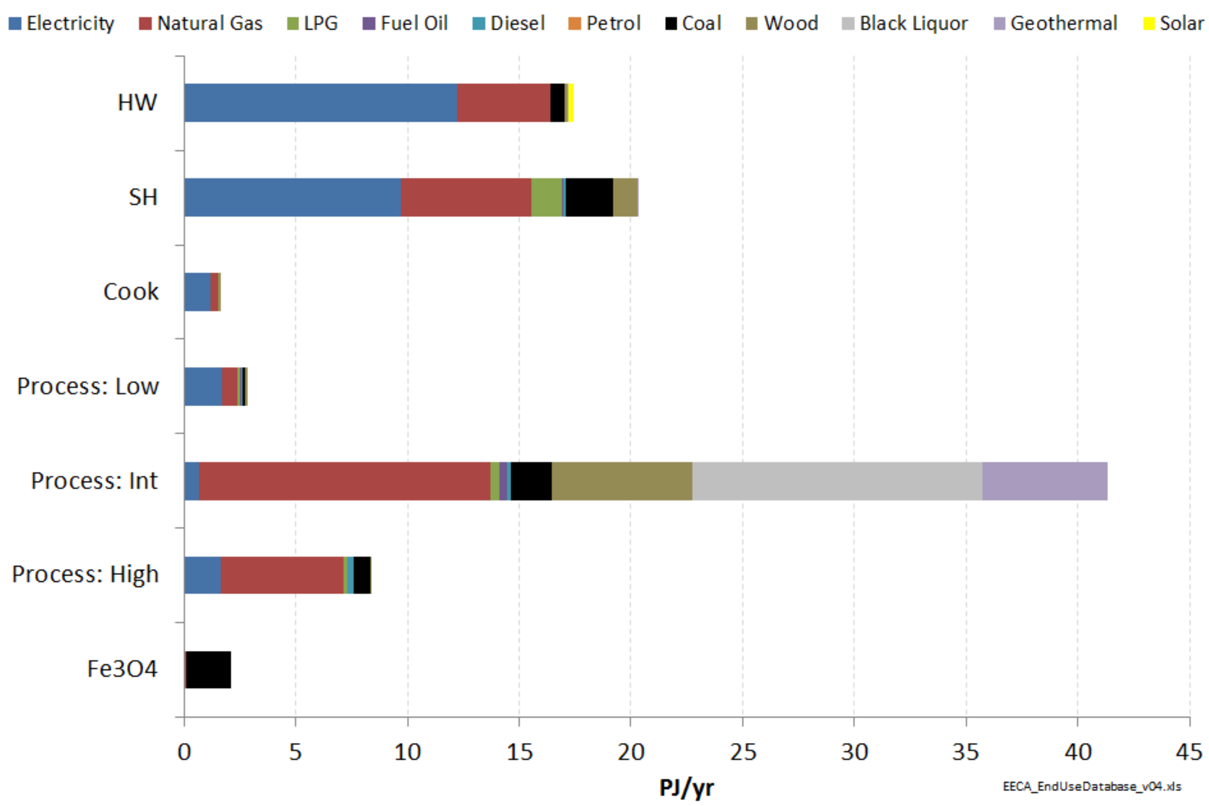
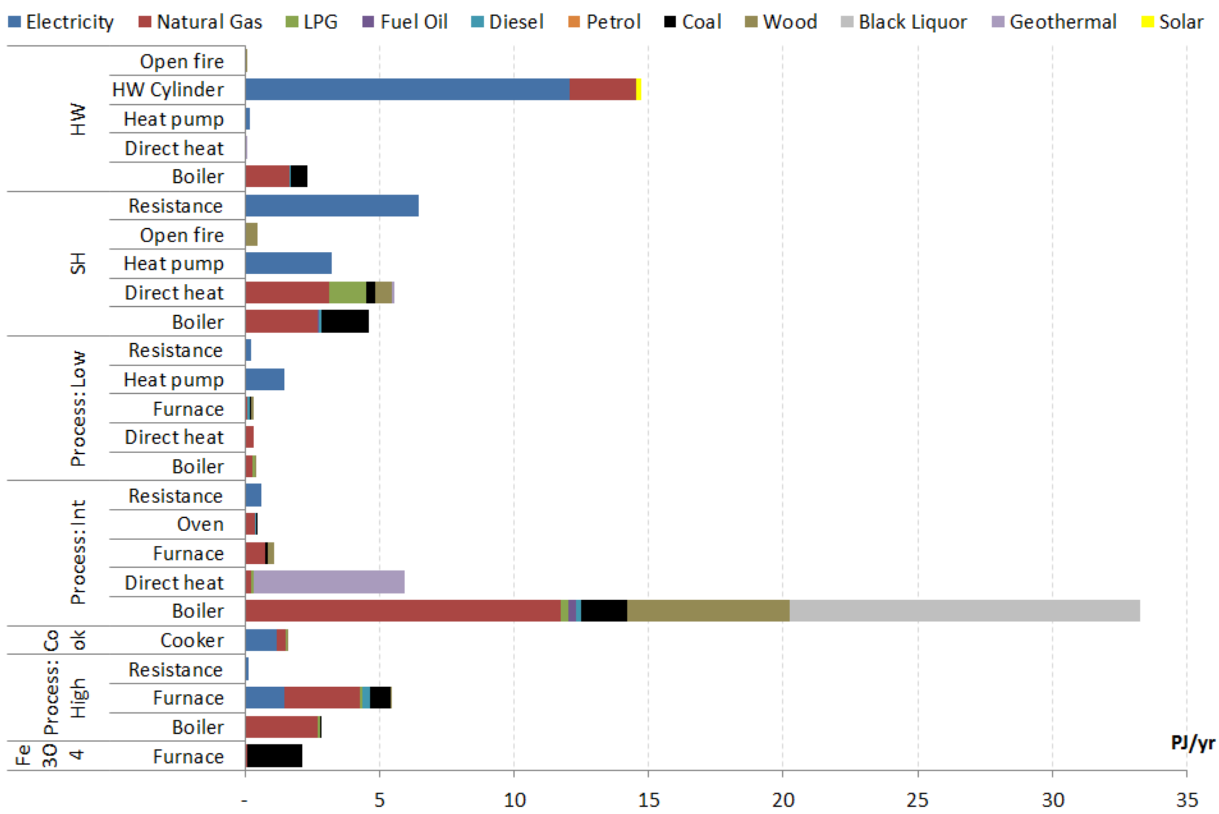


Figure 45 below provides a further level of detail, in terms of the appliance technologies used for provision of these energy services.

[54] HW = Hot water, SH = Space heating, FE3O4 is using gas for the reduction of iron oxides in steel manufacture.

Figure 45: Energy end-uses split by fuel and appliance / technology (for industrial, commercial and residential)



The above analysis indicates that future gas consumption for *energy*[55] purposes is likely to be dominated by the relative economics of gas versus other fuels for:

- Process heat boilers for industrial & commercial users
- Space heating for residential & commercial users; and
- Water heating for residential & commercial users

The balance of this section considers the key drivers of the relative economics of gas versus other fuels for these three uses.

Industrial & commercial process heat economics

Some consideration of the relative economics of industrial boilers has been undertaken to consider what are likely to be the key factors determining changes in demand for this gas end-use, and thus what are likely to be plausible future projections.

Part of this work involved discussions with a number of representatives from key gas consuming industrial sectors including dairy, forestry / paper, meat, steel, refining and food processing.

[55] i.e. not considering gas used as a feedstock or for power generation.

In addition, quantitative analysis was undertaken using a simple model to examine the potential lifetime costs of different types of boiler for the provision of process heat. The key inputs to the model were:

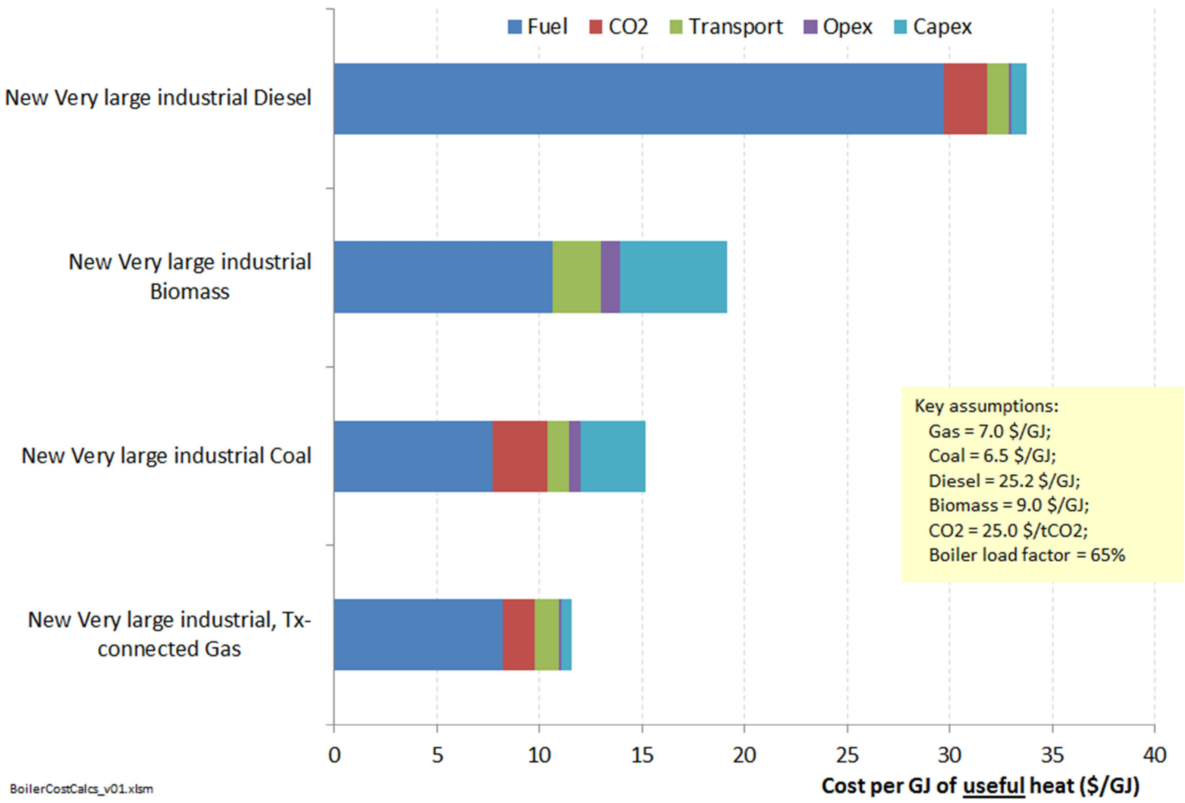
- Fuel prices
  - Wholesale costs
  - Transport / network costs
- CO2 prices & fuel emissions intensities
- Boiler efficiencies (these were deemed not to vary significantly between different types of boiler)
- Boiler capital and operating costs for the different types of boilers

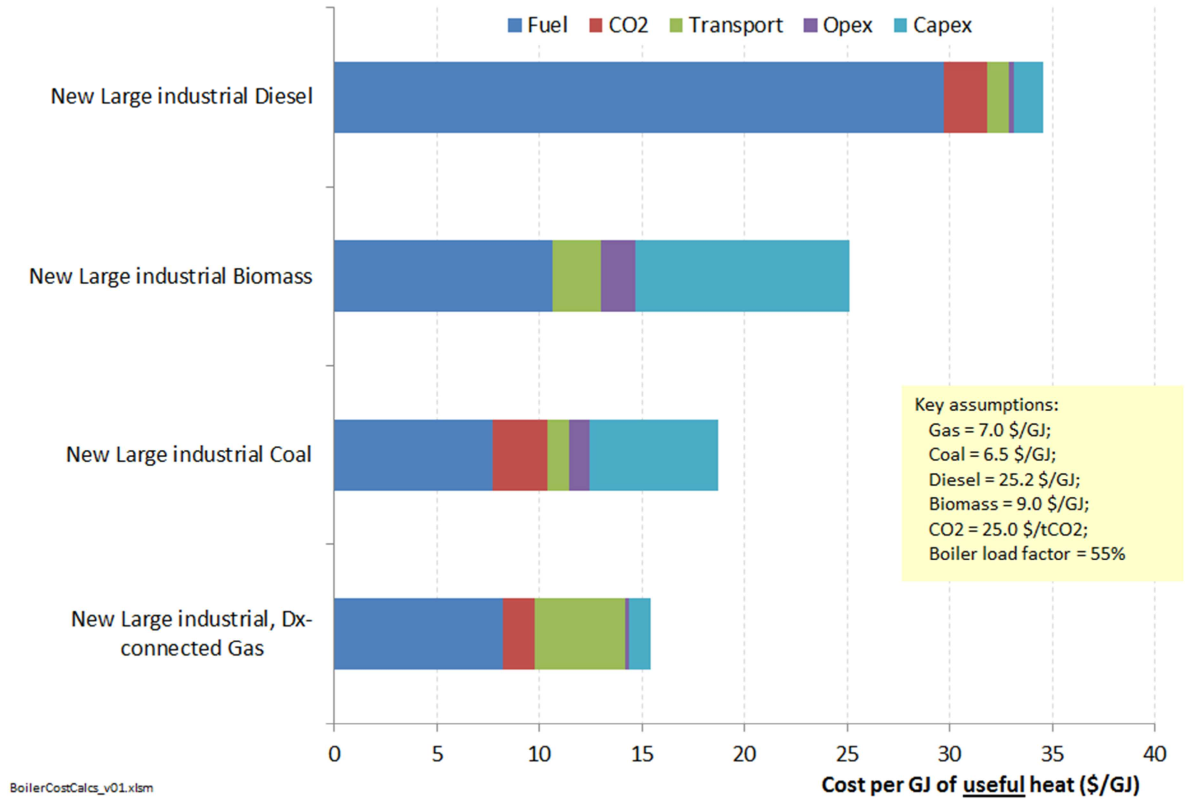
Although there can be site-specific factors which drive the relative economics of a fuel choice for industrial process heat (for example biomass fuel and transport costs can be very site specific), it is nonetheless possible to draw broad conclusions about the key drivers of the relative economics of different fuels for industrial process heat, and therefore develop internally consistent gas demand projections.

Figure 46 is an illustration of the output of such analysis for two different boiler sizes:

- Very large process heat boilers for the size of loads that would be directly connected to the gas transmission network (assumed to be 40 MWth)
- Large process heat boilers for the size of loads that would be connected to the gas distribution network (assumed to be 7 MWth)

Figure 46: Illustration of the relative economics of new-build boilers for industrial process heat





Based on this analysis and discussions with stakeholders, a number of observations and conclusions can be drawn.

Firstly, diesel is unlikely to be a serious contender while oil prices are around their current levels. (The $25/GJ diesel price was based on an international oil price of 100 US$/bbl). That said, discussions revealed that some industrial consumers were putting in *back-up* diesel systems to protect themselves against possible future gas interruptions such as the one experienced in October 2011 due to the outage on the Maui pipeline.

Coal and biomass systems face challenges due to their much more significant boiler capital & operating costs. Little public information appears to be available on boiler costs. However, one of the stakeholders interviewed (with significant experience with industrial boilers) provided some data on the relative capital and operating costs of different boilers (i.e. gas, coal, and biomass) and how such costs change with scale. The impact of the scaling with size can be seen in the fact that the operating and annualised capital cost numbers are materially smaller for the very large boilers compared to the large boilers[56].

This disparity between the capital and operating costs of gas versus solid fuel boilers was qualitatively confirmed by many other stakeholders who indicated that gas-fired boilers are much cheaper and easier to operate than solid-fuelled systems which need more complex boiler designs as well as fuel storage and handling, and ash storage and disposal facilities / equipment. Further, for food processing sites, the cleanliness of gas versus these solid-fuel alternatives was highlighted to be beneficial.

56 It is also partly due to the fact that the annualised capex number assumes a higher load factor (65%) for the very large boilers than for the large boilers (55%).

It was observed that biomass fuel and transport costs can vary significantly from situation to situation. Thus, while the $9/GJ biomass wholesale cost is considered a reasonable central estimate, it is understood that in some situations biomass can be significantly cheaper (i.e. where it is effectively 'on-site' and available as a by-product of another process such as in the Paper sector), whereas in other situations the transport costs could be more expensive in situations where the demand is located distant from the source.

On balance, therefore, it is considered likely that the main competitor fuel for gas for the provision of intermediate process heat is likely to be coal, except for specific situations where there is on-site availability of biomass or geothermal fuel as in the Paper sector.

Because of the relatively high capital and operating costs of coal-fired boilers, it is unlikely that coal will be the fuel of choice for *new* boiler investment decisions unless coal and CO2 prices are very low. Conversely, where parties have an *existing* coal-fired boiler (where the capital cost is effectively sunk) they are unlikely to switch away to gas unless coal and CO2 prices rise to significantly greater levels.

This is illustrated in Figure 47 below which shows the break-even CO2 price for different coal and gas prices for industrial process heat boilers. Two situations are illustrated:

- Very large, gas transmission-connected industrial process heat boilers; and
- Large, gas distribution-connected industrial process heat boilers.

Each graph has three different lines representing three situations:

- New-build, representing the choice for a party wishing to develop a completely new facility
- Existing coal, representing the choice for a party with an existing coal boiler (whose capital costs are effectively sunk), considering switching to a new gas-fired boiler (and thus incurring the capital costs)
- Existing gas, representing the choice for a party with an existing gas boiler considering switching to a new coal-fired boiler

For each line, any gas and CO2 costs to the bottom right of the line represents situations where it would be cheaper to go with coal, and to the top left of the line represents situations where it would be cheaper to go with gas.

The illustration is for a delivered coal price of $6.5/GJ. If delivered coal prices were to be $1/GJ less, say, then the lines would shift left along the x-axis by $1/GJ.

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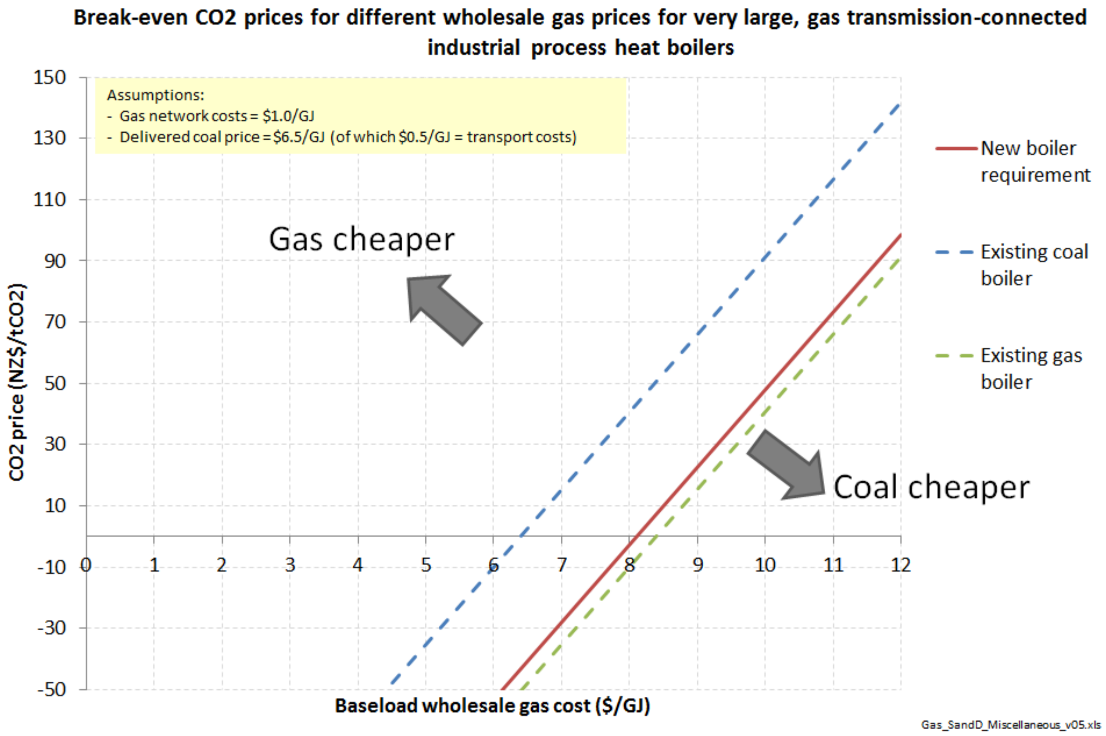
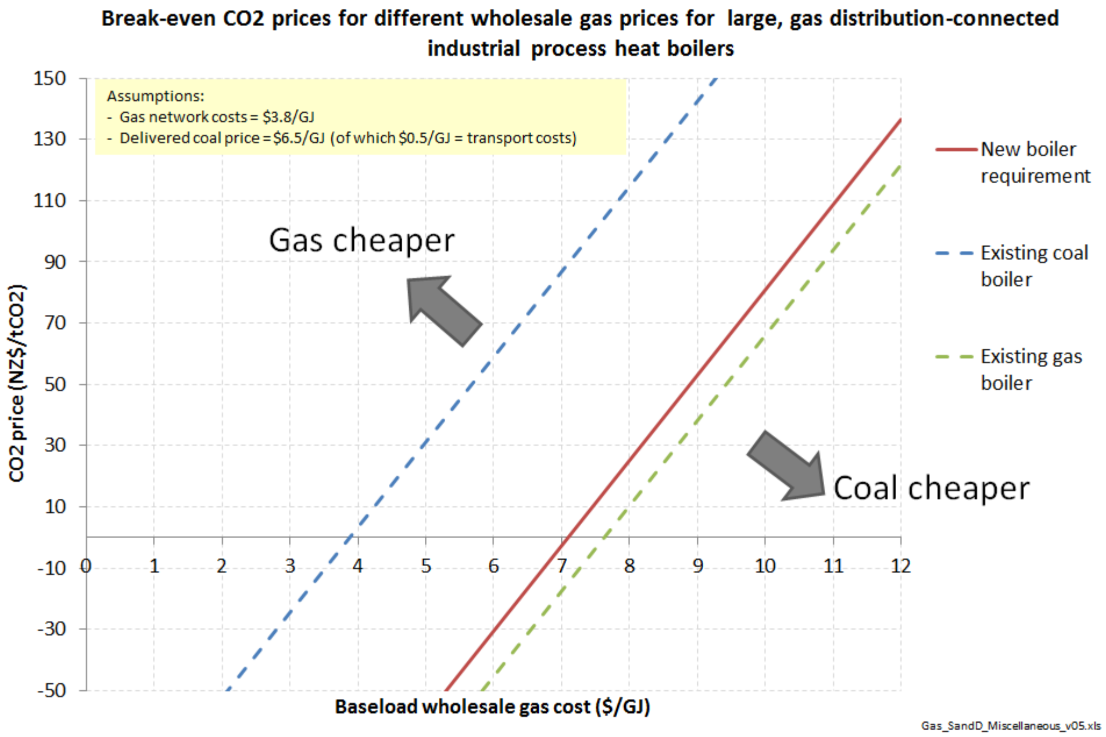
Figure 47: Illustration of the break-even CO2 price for different coal and gas prices for industrial process heat boilers





It is unlikely that parties facing new-build decisions will develop coal-fired boilers except if there is an expectation that gas prices will rise and be sustained at around $9-12/GJ, and CO2 prices don't rise beyond $50/tCO2.

If gas prices fall and are sustained below $7/GJ it is possible that some very large coal-fired boilers would be converted to gas, and also some large distribution-connected boilers if CO2 prices rise beyond $50/tCO2. However, as set out in Figure 45, there is not a large amount of North Island coal-fired boilers remaining which could switch to gas.

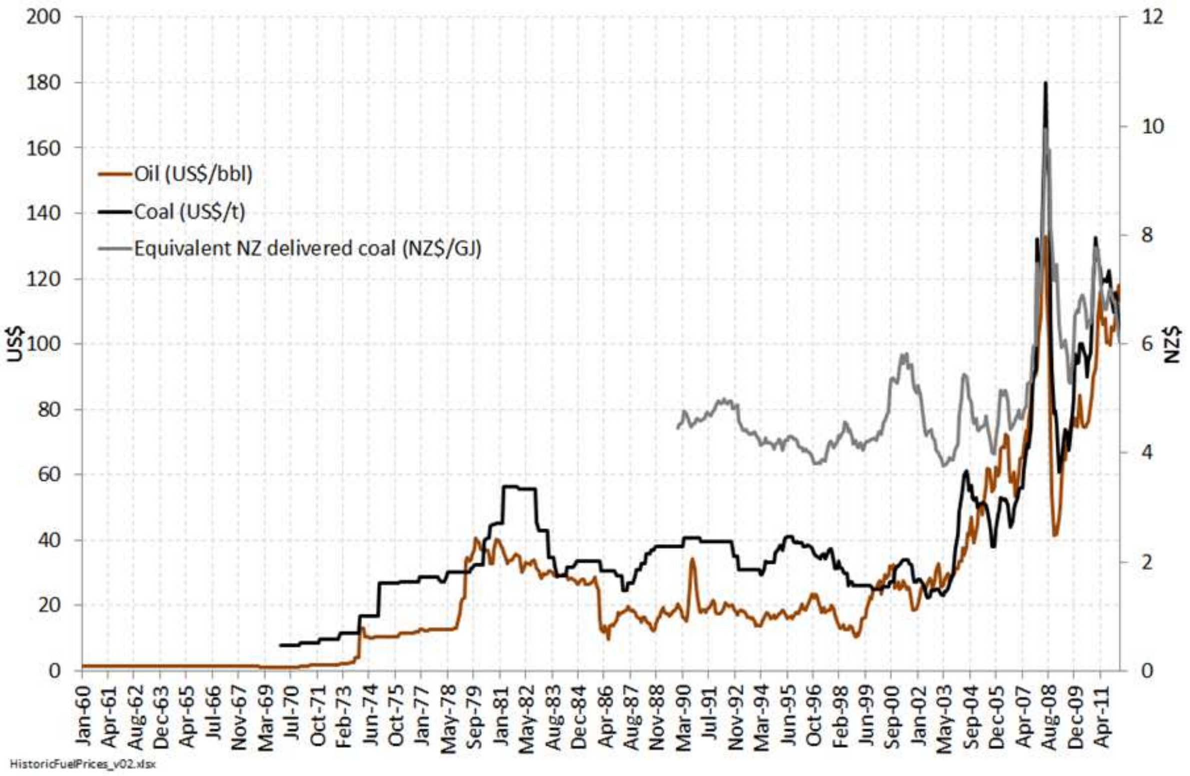
The economics of gas are less favourable for gas distribution-connected boilers relative to gas transmission-connected boilers because of:

- The significantly higher gas transport costs for distribution-connected parties ($3.8/GJ) compared with transmission-connected parties ($1/GJ)
- The higher per GJ capital costs for smaller-scale boilers, making the economics of switching away from an existing coal boiler more challenging for smaller heat loads.

With regards to the likely longer-term outlook for coal prices, New Zealand has for much of its history had North Island coal prices which were largely driven by the local supply / demand balance for Waikato coal. However, with the development of major coal import handling facilities at the Port of Tauranga and declining Waikato reserves, North Island coal prices are increasingly being driven by international trends.

Over the last decade international coal prices have trended upward, driven primarily by the growth in demand from China, India and other growing Asian economies. This is illustrated in Figure 48, which also shows how the movement in coal prices is increasingly similar to the movement in oil prices as they are both affected by the same underlying driver of world demand.

Figure 48: International coal and oil prices



The forward curve for coal suggests that international coal prices are likely to remain at elevated levels (albeit with some recent softening).

Turning to CO_2, Figure 24 and Figure 25 illustrated that while CO_2 prices are currently very low (approximately NZ$10/t$CO_2$) it is considered that there is likely to be more upward pressure on CO_2 prices than downward pressure, with longer term prices in the NZ$30-NZ$50/tCO_2 range likely, and prices greater than NZ$100/t$CO_2$ possible.

In summary, given the above considerations, it is concluded that underlying demand for gas for industrial process heat is most likely to grow modestly to meet growth in industrial demand for energy services, tempered by some switching to biomass and geothermal in the forestry / paper sectors, and also tempered by steady improvements to industrial energy efficiency[57].

Residential & commercial space and water heating

With respect to space and water heating, the analysis of the relative economics of the different energy end-use options becomes even more complicated in that it also requires consideration of different technologies (for example heat pumps) with their very different appliance costs and efficiencies, as well as consideration of fuel and transport / network costs. It also requires consideration of the different sizes of annual consumption, as fixed charges and capital costs can become material factors determining the best heating technology for the different sized mass-market consumers.

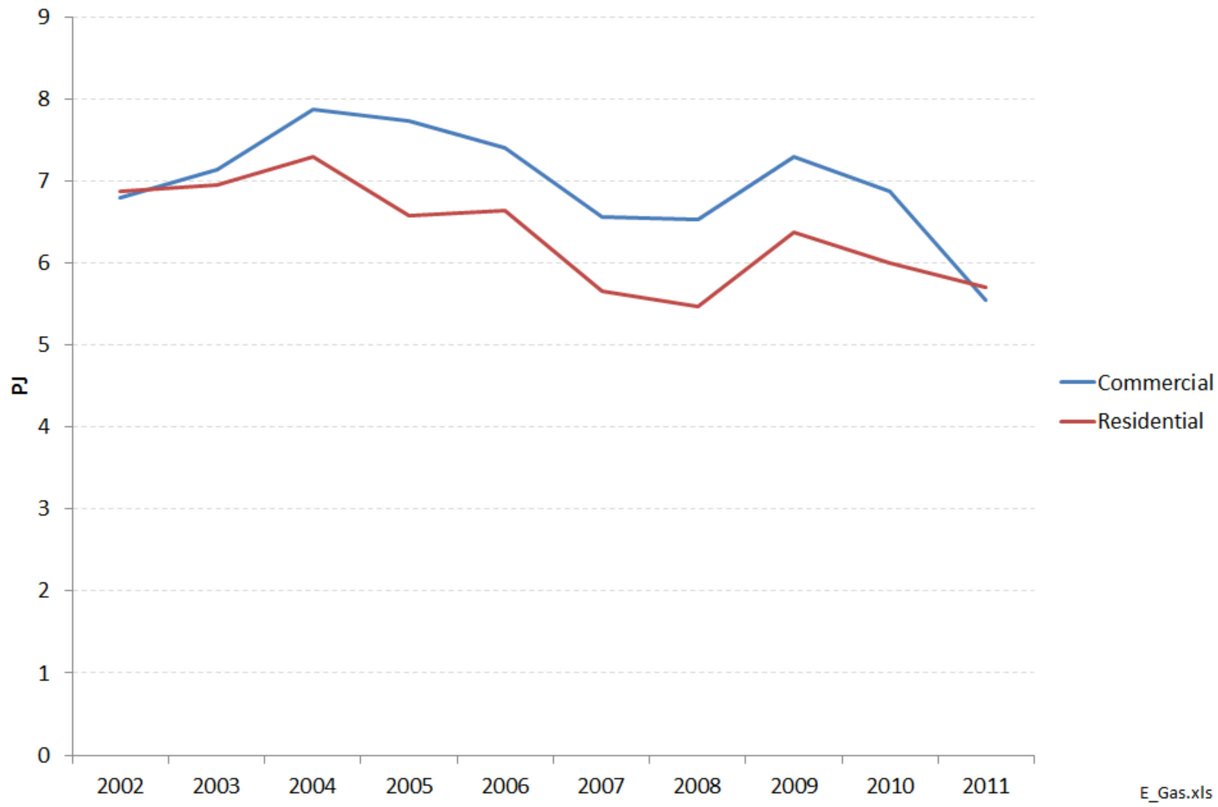
A full and detailed analysis of these issues is beyond the scope of this study. However, a previous study undertaken for Gas Industry Company indicated that instant gas hot water was likely to be the most competitive energy end-use option for water heating in most situations (plus it also delivers an advantage compared to cylinder options of never running out of hot water), but that for space heating gas would face stiffer competition from heat pumps. It also indicated that, in most cases, the relatively high capital costs of non-industrial heating requirements would mean that it was not generally cost-effective to switch away from an existing heating option. Furthermore, the best fuel option could vary significantly with customer circumstance – particularly the size of the heating load.

Initial indications from an update to this study are that these conclusions remain valid, and that these are consistent with observed outcomes in the marketplace. (For example, discussions with gas network companies indicate that gas is losing space heating market share, but remains competitive for water heating).

Data from the MBIE Energy Data File shown in Figure 49 indicates that gas consumption for the commercial and residential sectors (whose use is dominated by space and water heating) has been dropping in recent years. This tends to support the above conclusions that gas is slowly losing market share for space heating.

57 In this respect, a number of the industrial stakeholders interviewed indicated that they had been able to meet much of the incremental growth in demand using their existing production facilities by implementing energy efficiency measures.

Figure 49: Historic gas consumption in the commercial and residential sectors



Source: Concept analysis using MBIE 2012 Energy Data File data

On balance, it was considered that there would be likely to be some continued growth in demand for gas for water heating, but relatively flat demand (possibly declining in some scenarios) for gas for space heating.

3.4.1 Summary projections

The analysis and information set out above has been used to develop demand projections for the main uses of gas (space heating, water heating, and process heat) and for the different key sectors. The resulting scenario projections are shown in Table 3.

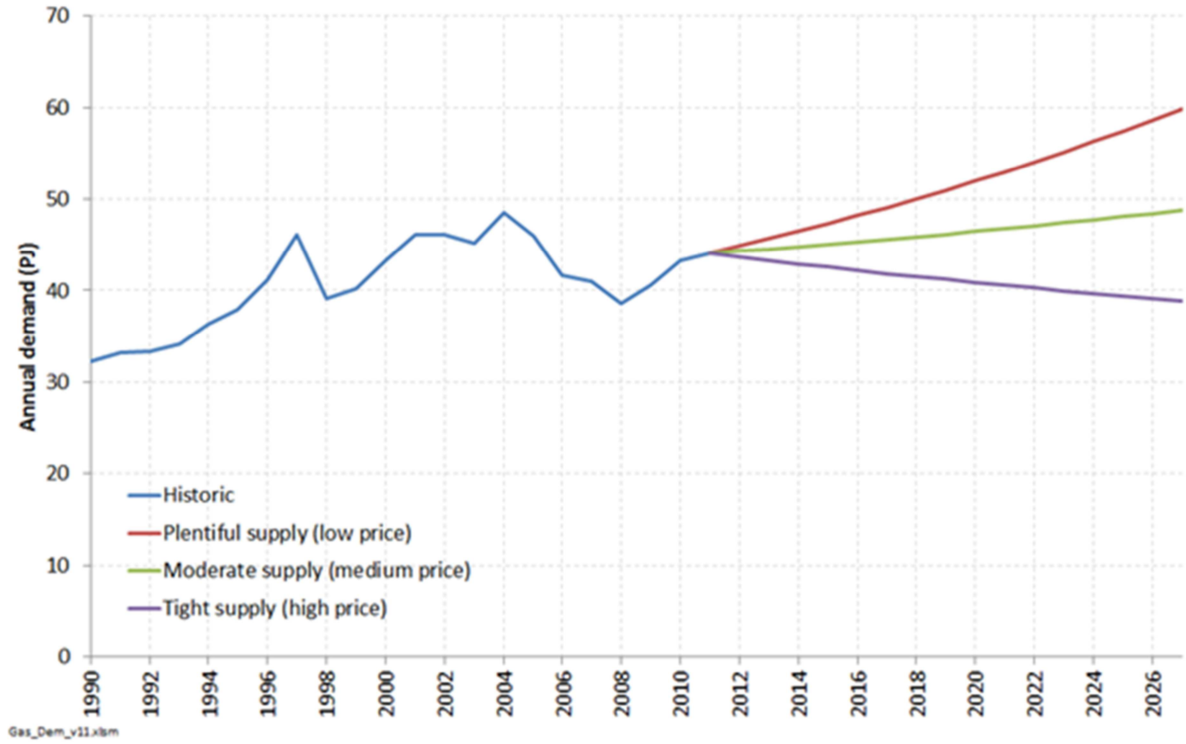
Table 3: Projected annual gas demand growth rates for gas supply scenarios

	Projected annual growth rates for gas supply scenarios									Load splits		
	Space heating			Water heating			Process heat					
Sector	Plentiful	Moderate	Tight	Plentiful	Moderate	Tight	Plentiful	Moderate	Tight	Space heating	Water heating	Process heat
Non	0.25%	-0.50%	-2.00%	4.00%	2.00%	0.00%	3.00%	1.50%	0.00%	55%	40%	5%
ToU	0.25%	-0.50%	-2.00%	4.00%	2.00%	0.00%	3.00%	1.50%	0.00%	10%	5%	85%
Dairy							0.50%	0.00%	-0.75%			100%
Paper							0.00%	-2.00%	-4.00%			100%
Meat							2.00%	1.00%	0.00%			100%
Refining							2.00%	1.00%	0.00%			100%
Steel							0.50%	0.00%	-0.50%			100%

Source: Concept estimates

Figure 50 translates the above scenarios into overall projections for gas demand from the industrial, commercial & residential sector.

Figure 50: Projected movements in industrial (ex-petrochemical), commercial & residential gas demand



Source: Concept estimates

Under the low price scenario, the rate of gas demand growth increases to approximately 1.9%/year, reflecting the combined effect of economic growth and some expansion in gas market share relative to other primary energy sources.

Under the medium price scenario, gas demand is projected to grow at around 0.6%/year. Under the high price scenario, gas demand is projected to modestly decline from current levels at approximately -0.8%/year, but remain around 40 PJ/year. This reflects the relatively limited scope for further cost-effective fuel substitution away from gas among large industrial users, and the fact that underlying well-head gas costs are a modest proportion of delivered gas prices for residential and commercial users.

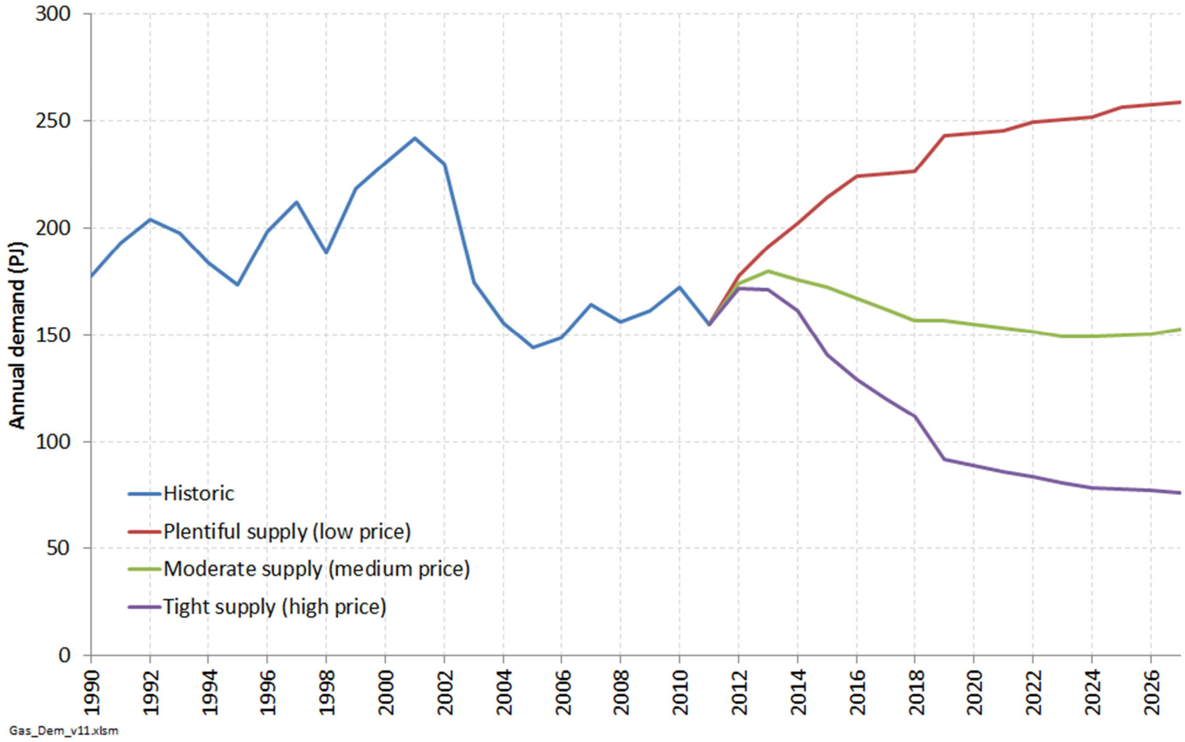
3.5 Overall projections of gas demand for New Zealand

Figure 51 aggregates the demand projections for the different sectors. The key observations are:

- under the low price scenario aggregate gas demand grows strongly to reach over 250 PJ/year, surpassing the historic demand high reached in 2001;
- under the medium price scenario aggregate gas demand is similar to recent levels; and

- under the high price scenario aggregate gas demand declines gradually to settle at around 75 PJ/year.

Figure 51: Projected total annual gas demand



Source: Concept estimates

Figure 52 below compares the projected level of demand in 2027 under the different price scenarios with historic demand for 2001 (the historic peak year of gas usage) and 2011 (the most recent year for which official data is available).

Changes in gas demand across the price scenarios are clearly concentrated in the petrochemical and power generation sectors. This is not surprising because these sectors are the most price sensitive, with gas comprising a large proportion of final product prices, and there is ready availability of competing substitutes. By contrast, demand for gas within the industrial, commercial and residential sector is less affected by changes in well-head gas prices.

Furthermore, the chart again illustrates the 'shock-absorber' role fulfilled by the petrochemical and (to a lesser extent) power generation sectors, given that they provide a volume market for gas when it is plentiful and relatively inexpensive, but can reduce demand if reserves become scarce. As noted earlier, this helps to underpin gas exploration and development activity, and can provide a buffer to extend the remaining life of existing resources if reserves to production ratios start to decline.

Figure 52: Historic and projected total annual gas demand

Source: Concept estimates, Ministry of Business, Innovation and Employment

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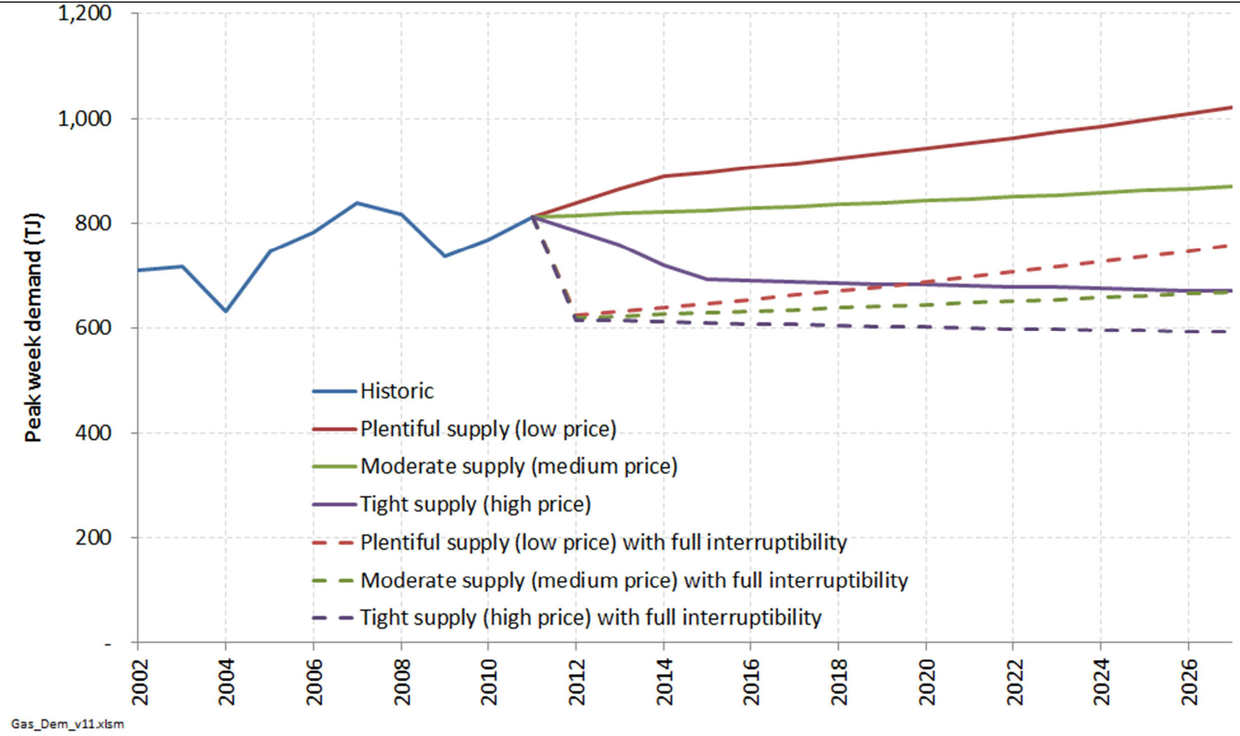
4 Peak demand scenarios and pipeline investment

Chapter summary

- The existing pipeline system is expected to have sufficient capacity to accommodate the projected scenarios with higher demand.[58]
- The only significant exception is Vector's northern pipeline system (from central Waikato northwards). This system has already reached its capacity limit during peak weeks, and it appears that some potential new gas demand is being suppressed in this region through an inability to secure pipeline capacity.
- However, some gas users (e.g. power generators) appear to have relatively low cost options to reduce their usage during peak demand periods
- The scale of this potential is such that, if it can be harnessed, the need for costly new investment may be deferred for many years – as shown in the chart below – and it would allow currently suppressed potential new demand to connect to network.
- To harness such potential would require changes to pipeline pricing and access regimes, in order to send better signals to pipeline users of the cost of pipeline capacity at times of peak demand. The means by which such changes could be effected is beyond the scope of this study. However, this study does appear to indicate that relief of pipeline congestion in the North system through altered pricing and access arrangements would be a worthwhile achievement.

Figure 53: Projections of peak week gas demand on the Vector North gas transmission system

[58] Some investment would likely still be required in some specific areas – but not to the extent of requiring major new pipelines. New pipeline investment might also be required to connect new gas finds in locations such as the East Cape to the national transmission system.



Source: Concept estimates

- It is unlikely that new gas-fired generation would be developed in a location requiring connection to the Vector transmission system, but would instead be developed in Taranaki or a location along the Maui pipeline in the Waikato. This is because:
  - There are greatly reduced electrical benefits from locating a power station in Auckland or Northland due to major electricity transmission upgrades.
  - Conversely, a gas-fired power station in Auckland / Northland would likely incur significant gas pipeline upgrade costs.

4.1 Peak demand drivers

The previous chapter set out scenario projections of annual demand. However, annual demand is not the key parameter that drives decisions around network operation and investment. Rather, it is *peak* demand.

This is because gas pipes have a finite amount of capacity to transport gas. While the levels of gas being transported remain below this capacity, the costs of operation are relatively low – largely comprising the operating costs associated with compressors and the like to flow the gas along the network.

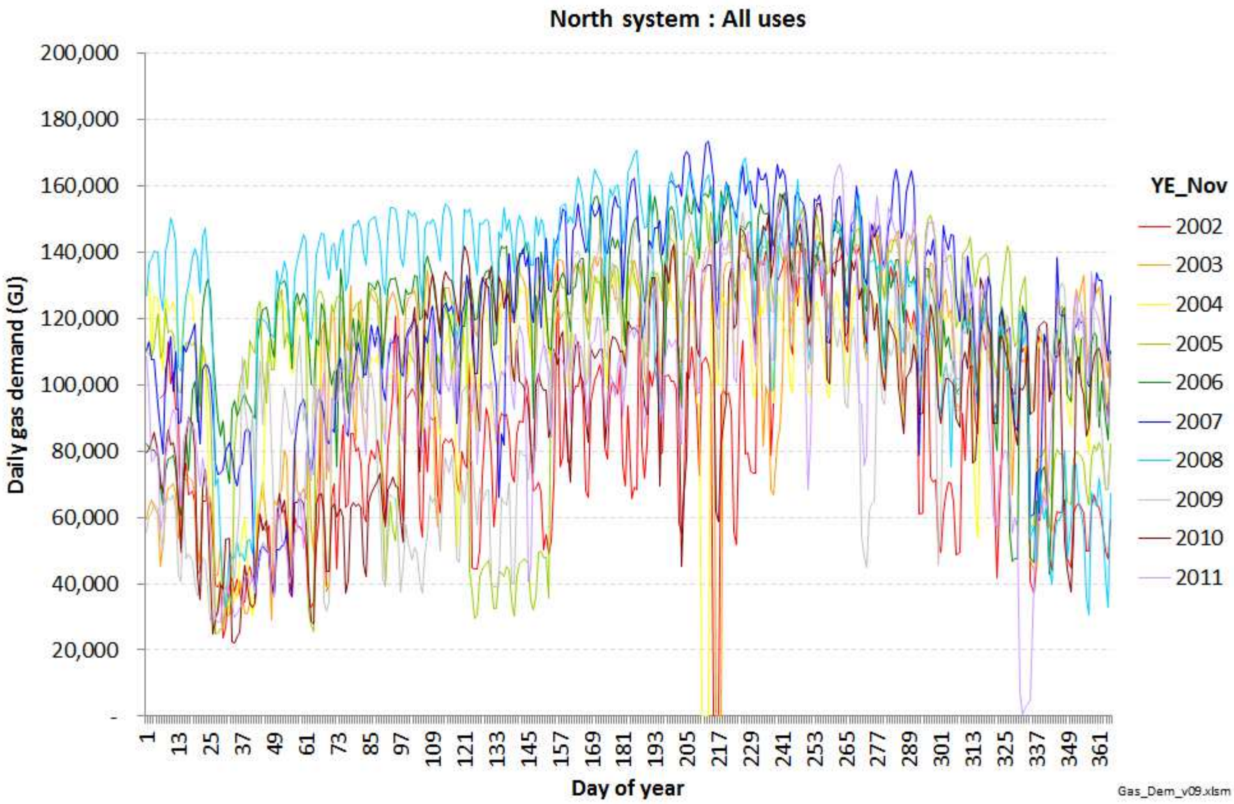
However, if demand rises above this capacity level, gas could not be transported without breaching safety thresholds. Once this level of demand is reached, some gas demand will need to be curtailed to keep pipeline flows below this capacity limit. Greater flows of gas cannot be realised until investment is made in the pipeline to upgrade its capacity.

The principal regional system where such capacity constraints are being reached is the North network, whereas most other parts of the Vector transmission network are understood to have headroom to accommodate demand growth.

This section of the report therefore focuses on the North system. However, the model and associated analysis is capable of looking at all systems using exactly the same broad framework.

As shown in Figure 54 below, there is a wide variation in the level of daily gas demand on the Vector North system. Patterns that can be seen include a weekly cycle, a seasonal (winter-summer) variation, public holiday effects (for example Christmas occurs around day 25 in this data series given the 1 December start to these years), plus there can be significant year-to-year and week-to-week variation.

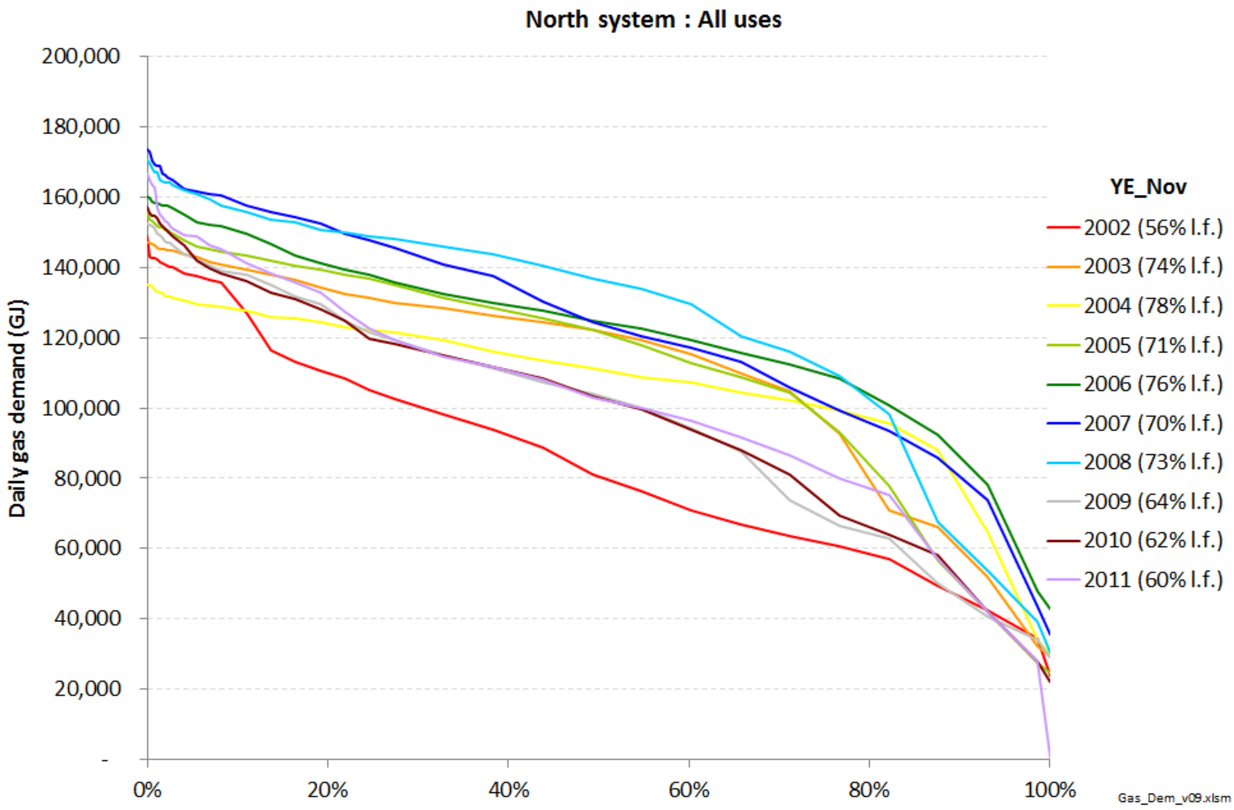
Figure 54: Historic total daily gas demand on Vector North system[59]



[59] Due to data availability when this analysis was undertaken, and the desire to use as much data as possible (including the August 2011 severe weather event), the years presented in this analysis are years ending 30 November.

Figure 55 re-arranges the data from Figure 54 into a duration curve format. This more clearly illustrates how for the vast majority of the time, gas demand is significantly below peak levels.

Figure 55: Duration curves of historic total daily gas demand on Vector North system



The duration curves also indicate that since 2004, demand on the North system has been getting steadily peakier, as indicated by the reducing load factor shown in the graph key[60].

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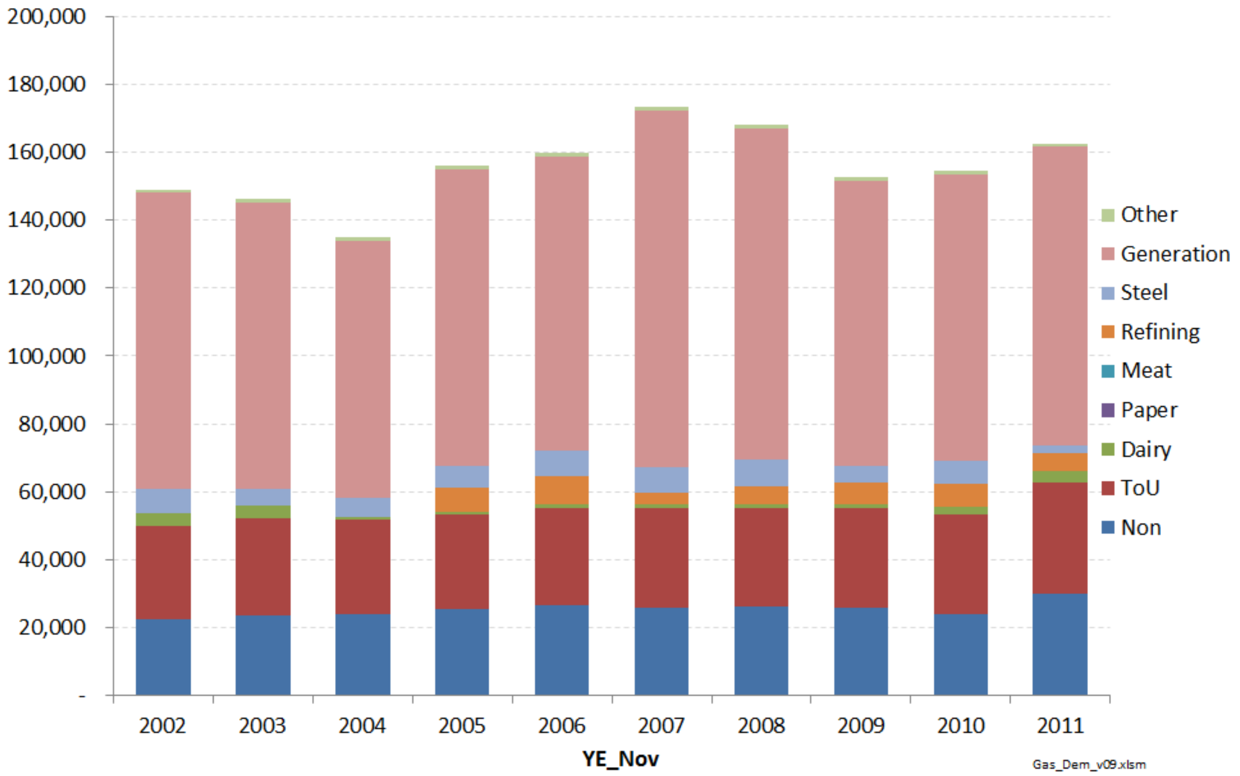
60 The load factor is calculated as the average demand level divided by the peak demand level.

Figure 56 sets out further analysis to understand what has been contributing to the peak, and the year-to-year changes in its magnitude.

Figure 56: Historical sectoral composition of peak day demand for Vector North system (GJ)

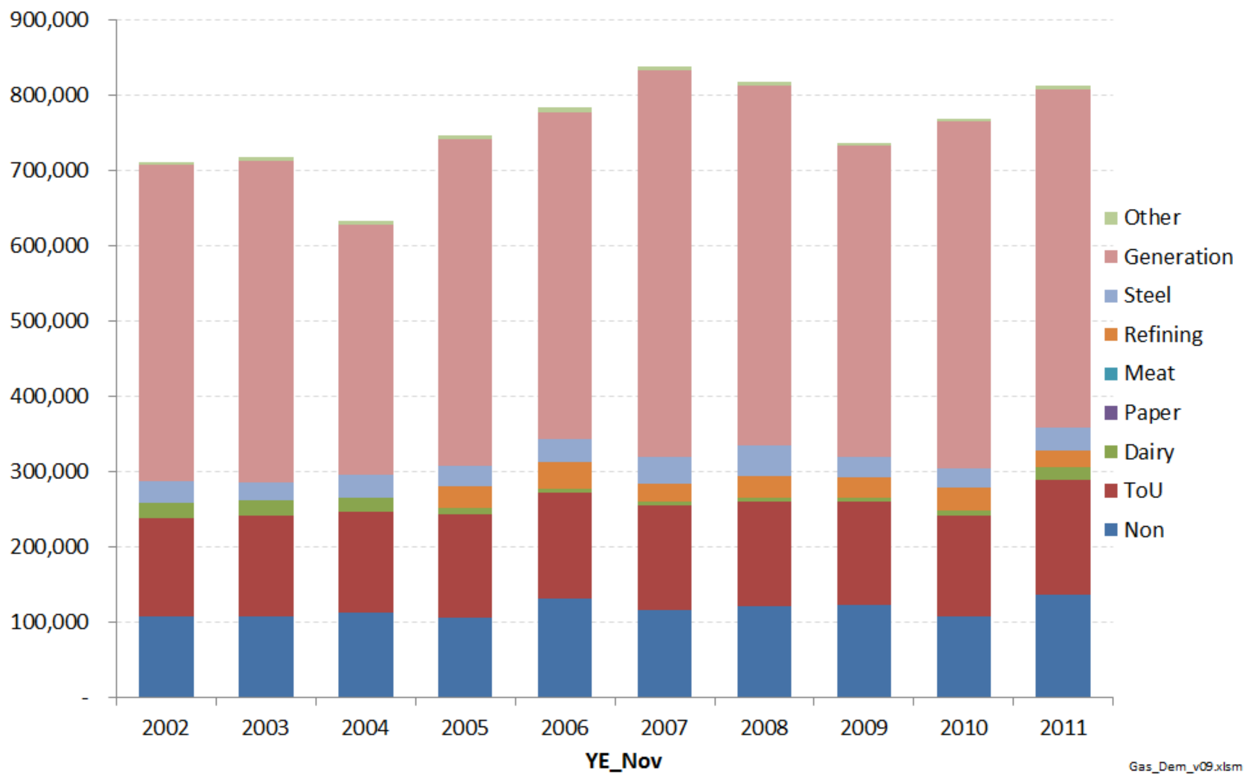


Power generation has been the most significant contributor to peak day demand on the North system. Also, when compared with Figure 37 on page 61, it can be seen that there has been less year-on-year change in peak demand than annual demand.

Although it is often useful to consider things in peak *day* terms (for example "maximum daily quantity", or MDQ, is a key parameter in most gas contracts), the critical time period for pipeline capacity issues for the North system is understood to be closer to a *week*. This is because of the ability of line pack to absorb a one-off peak day, but after a series of consecutive very high daily demands, line pack levels will eventually drop below the critical threshold.

Accordingly, Figure 57 show analysis to help understand what contributes to peak *week* demand on the Vector North system. (Week is considered to be the working week of Monday to Friday, rather than the calendar week of Monday to Sunday).

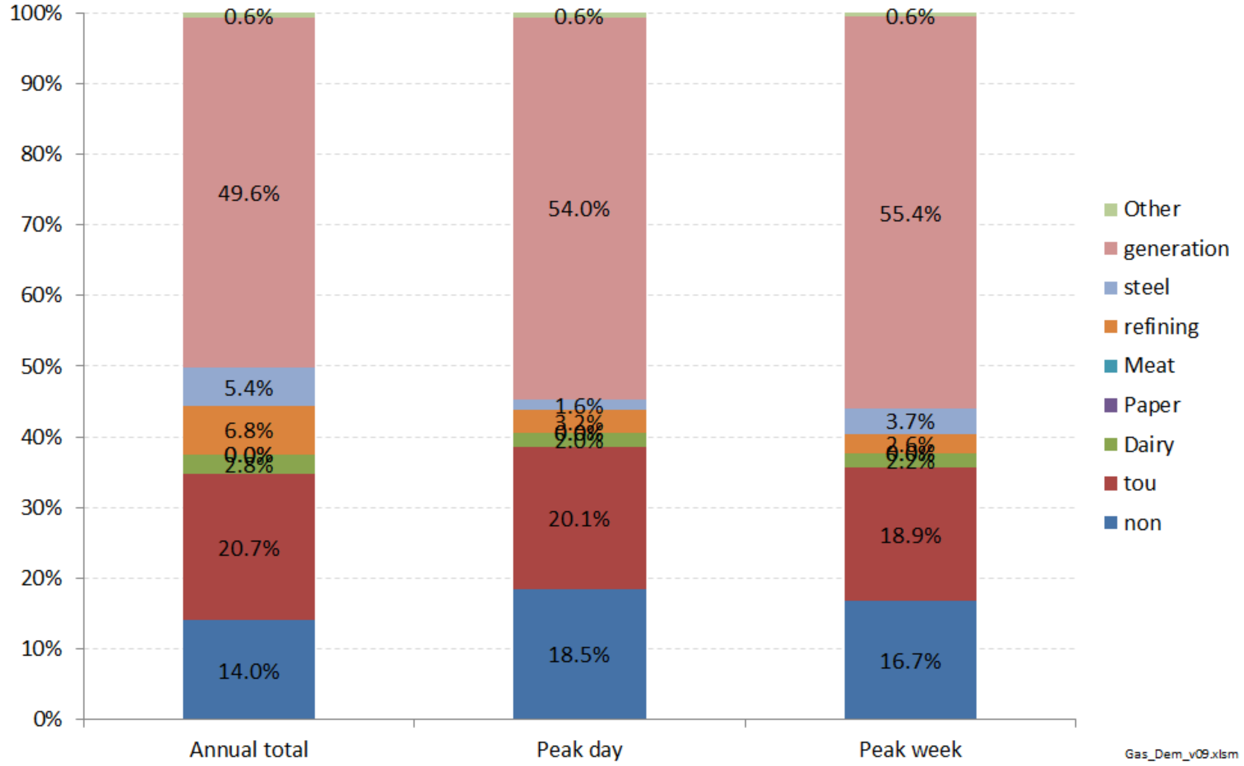
Figure 57: Historical sectoral composition of peak week demand for Vector North system (GJ)



As can be seen, the proportions of different sectors is broadly similar to peak day demand.

Figure 58 further illustrates how the proportions of the different sectors to the North system demand total vary according to whether demand is measured as an annual quantity, or on some measure of peak.

Figure 58: Sectoral proportions of gas use for YE Nov 2011 for different time periods for Vector North system



Due to the inherent variability of demand driven by factors such as the weather, and 'natural' randomness in the coincident level of demand from consumers, to model peak demand necessarily requires the ability to consider the probabilities of demand reaching certain levels, and thus estimating what a (say) 1-in-20 year or 1-in-50 year level of peak demand would be. This exercise has some key inherent challenges:

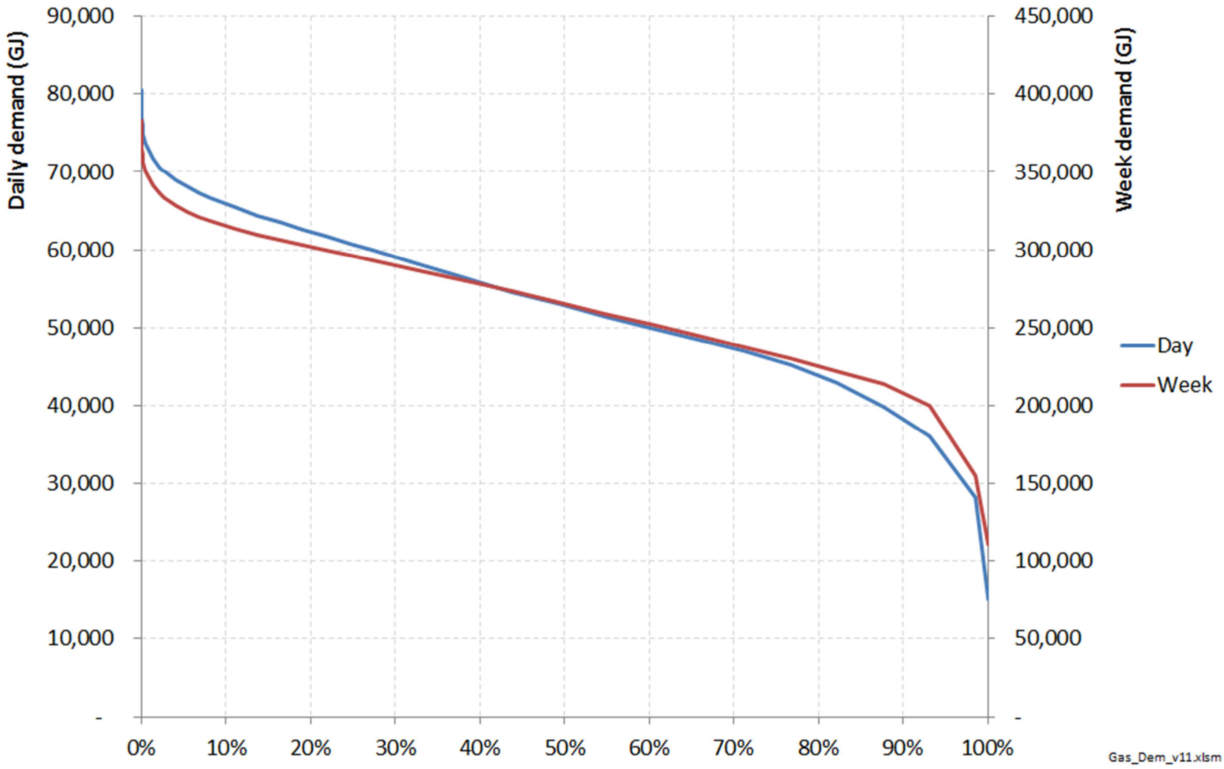
- There is only a limited historical gas demand data set (just over ten years), meaning that just considering this data alone would make it hard to infer what a 1-in-50 year peak demand, say, might look like;
- There is a need to be able to consider peak demand over different lengths of time, ranging from a day through to a week, given that the critical time-period for different pipelines can vary;
- Different demand sectors exhibit different seasonal and diurnal patterns, and different temperature sensitivities, yet the proportions of these different sectors has varied during the historic data series, and is likely to vary further into the future.

To address these issues, a statistical model was developed which sought to estimate the relationship between demand and key observable drivers (namely temperature and temporal parameters (for example day of week, month of year, public holidays)). This model is described in detail in Appendix A.

It broad terms, it enables projections of *peak* demand for the different pipeline systems to be developed based on the underlying assumptions regarding *annual* demand growth for the different sectors as described in section 3.4, assuming that historic peak/annual relationships are maintained for each sub-segment of gas usage (power generation, industrial etc).

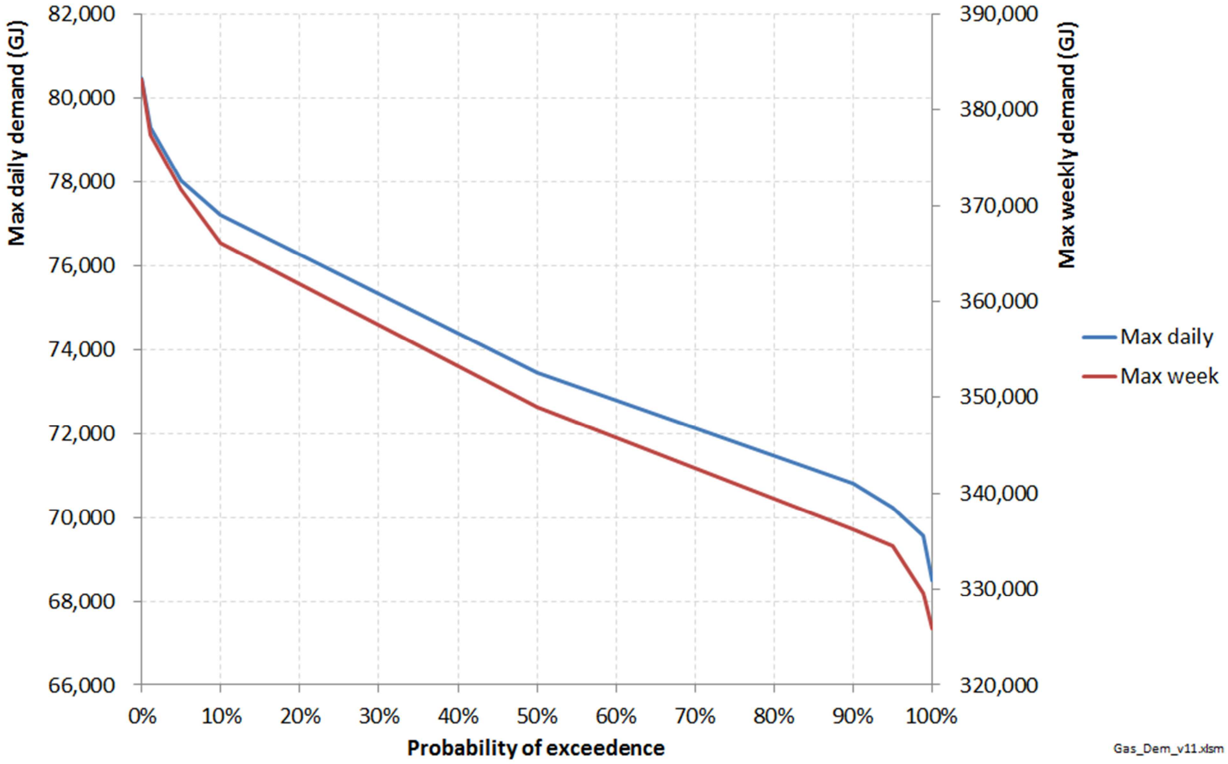
The statistical analysis revealed that, due to factors such as the extreme temperature-dependency of sectors such as Non-ToU demand, the overall system load duration curve is quite 'peaky'. As Figure 59 below illustrates, 8.4 % of the pipeline capacity used by *non-generation* demand is required for only 0.5 % of the time.

Figure 59: Modelled duration curves of non-generation demand on the North System



The analysis further revealed that there is a significant range of possible peak day and peak week demands that may be experienced in a year due to the year-on-year variability introduced by the weather and the 'natural' randomness of demand. For example, Figure 60 below illustrates the modelled range of possible non-generation peak outcomes in the North system.

Figure 60: Modelled range of possible non-generation peak outcomes in the Vector North system



Thus, this modelling suggests that the range between maximum and minimum peak possible peak week outcomes is equivalent to 16.4% of mean peak week demand, and that a 1 in 10 year peak week demand would be 4.9% higher than the mean peak week, but a 1 in 99 year peak week demand would be 8.1% higher.

This raises issues as to the appropriate security standard Vector should operate the pipeline with respect to allocating capacity such that peak demand is not expected to exceed a 1 in 'x' year event. However, it is not within the scope of this study to consider what such a security standard should be.

Further, such statistical analysis makes no consideration of the potential for changes in consumer behaviour at times of peak demand. Such changes may emerge if consumers face altered price signals as a result of changes in the design of pipeline pricing and access arrangements. Such changes are indeed being considered by the Gas Industry Company and Vector, and recommendations have recently been put forward by the Panel of Expert Advisers[61]. Amongst other things, this includes a high priority recommendation that pricing and access arrangements are altered to signal to consumers the value of scarce pipeline capacity to facilitate more efficient capacity allocation.

Accordingly, the following sub-section considers the potential impact that increased 'interruptibility' could have on peak demand.

61 http://gasindustry.co.nz/sites/default/files/u254/pea_advice_to_gic_180215.7.pdf

4.2 Interruptibility

If demand for a network exceeds the available capacity that is able to be supplied, one option to relieve such a situation is to invest to increase the network capacity.

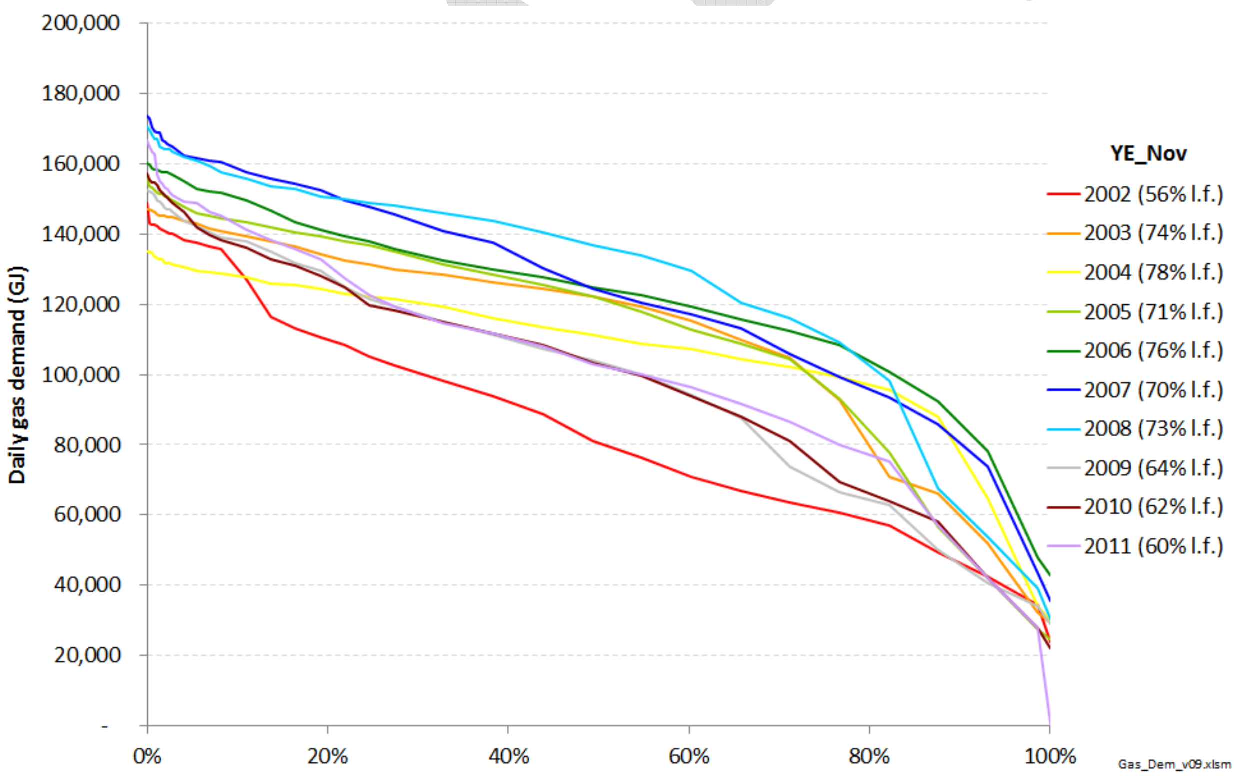
However, another option that may be more economic is for some consumers to curtail their demand at times of peak, thereby enabling other consumers who value the gas more highly to satisfy their demand. Such interruption of demand to some consumers to relieve the peak could postpone the need for capital-intensive network investment.

Interrupting demand could potentially be a more cost-effective solution than network investment if:

- The peak period is for a relatively short amount of time; and/or
- There are some consumers whose value of demand is significantly lower than others; and/or
- Network investment is relatively expensive.

With regards to the first point, Figure 61 illustrates that times of peak stress occur relatively infrequently on the Northern System, thereby raising the potential for some consumers demand to be curtailed for relatively short periods of time in order to help relieve such congestion.

Figure 61: Duration curves of historic total daily gas demand on Vector North system



With regards to some customers potentially having a relatively low value of load, numerous studies have been undertaken of the value of load for different types of customer for both the electricity and gas sectors. They reveal major differences in the value of energy to different groups of customers, and raise the potential for some customers to economically curtail their gas demand for relatively short periods at peak, rather than invest in extra pipeline capacity.

In addition to these differences in customers' 'inherent' value of gas, there may also be significant opportunities for some customers to curtail their demand for a short period of time because the energy service could be satisfied by a back-up fuel option.

From discussions with stakeholders, it is apparent that there is some potential for both types of gas interruption from a number of different customers:

- Some consumers indicated that they had some relatively low value processes on their site which they may be able to curtail for relatively short periods of time without incurring excessive cost; and
- Some consumers indicated that they have back-up energy options which they could switch to such as diesel. Indeed, it is understood that a number of these back-up energy options have been put in place following the 2011 Maui pipeline outage.

Some consumers indicated that they felt there was significant potential for interruption at times of peak to manage pipeline capacity issues, but that there was not currently a strong price signal for them to deliver such interruptible potential. Indeed, to-date it is understood that only one customer currently has an interruptible pipeline contract with Vector: the refinery at Marsden Point[62].

Analysis was undertaken to determine whether demand interruption could indeed make a significant contribution to managing pipeline capacity constraints, with a particular focus on the North System. If demand interruption was revealed to potentially be an economic option, it could have a major bearing on future levels of peak gas demand. The analysis focussed initially on gas used for power generation.

As shown Figure 62, gas used for electricity generation is the biggest contributor to peak week demand on the Vector North system.

62 Under the terms of this contract, Vector can interrupt flows of gas to the refinery at times of pipeline capacity constraint. In return, the refinery pays a lower $/GJ fee than other users of the pipeline who have an uninterruptible contract. Vector calls upon this interruption to manage congestion on the whole of the North system, as well as more localised congestion in the pipeline north of Auckland. It is further understood that the refinery can manage such interruption primarily by switching to an alternative fuel during such periods (essentially diverting hydrocarbons away from being processed into an end product, and instead burning them as an input fuel).

Figure 62: Historical sectoral composition of peak week demand for Vector North system (GJ)

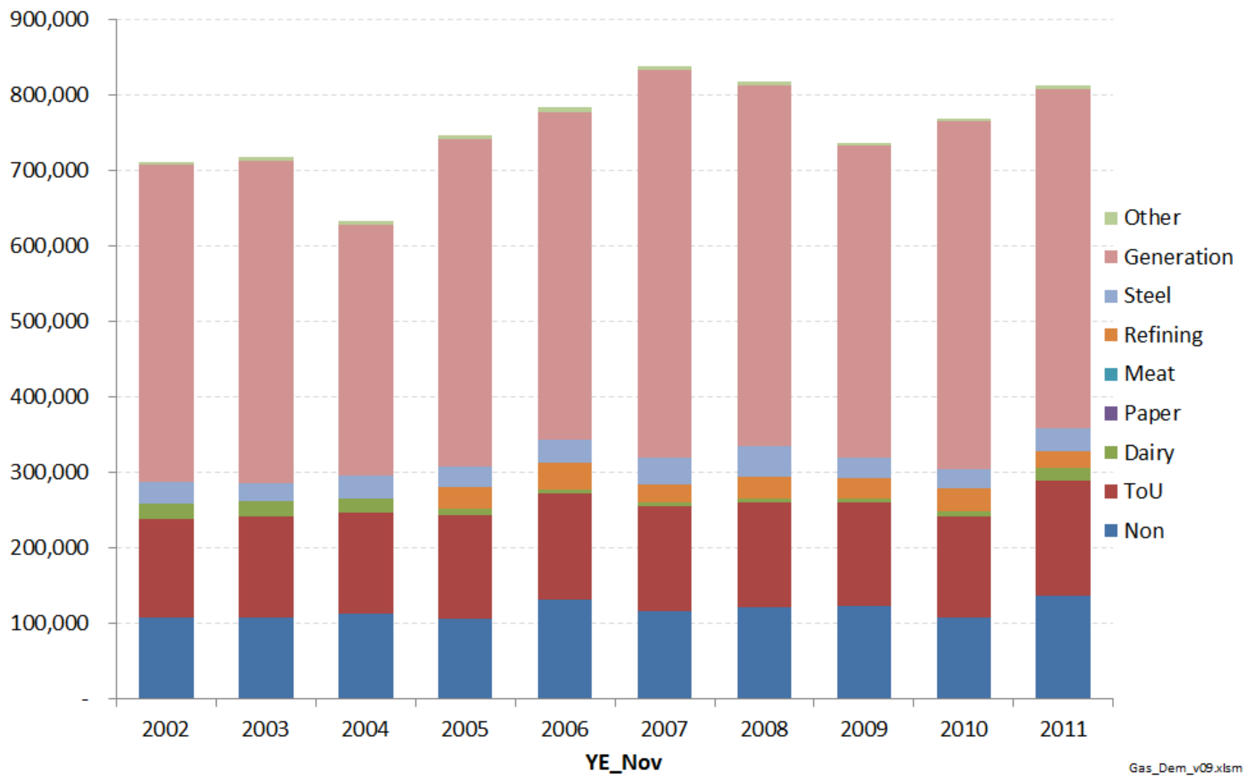
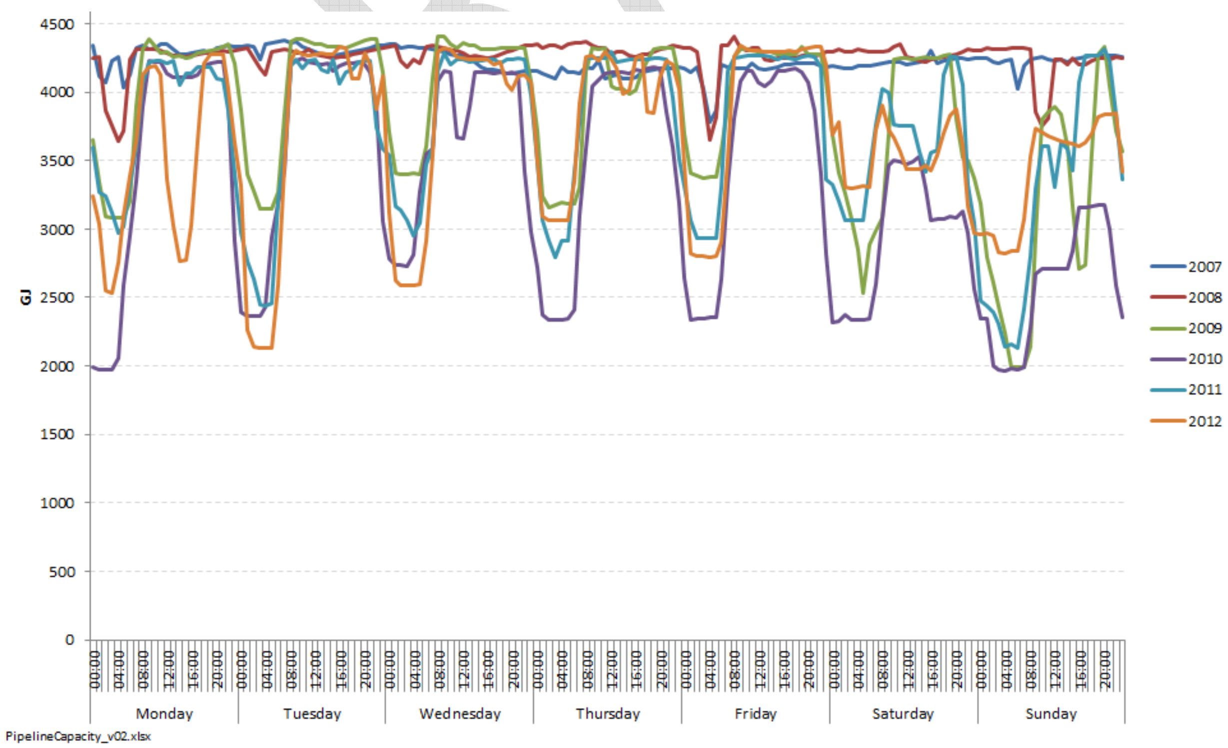


Figure 63 gives more insight as to the type of operating pattern being undertaken by the two gas-fired generators in the North System (Otahuhu B and Southdown) during these peak weeks.

Figure 63: Otahuhu B + Southdown hourly gas consumption during YE June peak weeks



During the daytime the generators were operating at close to full capacity, but reducing demand during the night. In some cases there appears to have been some demand reduction during the mid-day period, but not down to overnight levels. During the 2008 peak week (which was during an electricity hydro-shortage) there appears to be hardly any reduction at all.

One issue that was considered was whether there was potential for the two Auckland-based generators to reduce their generation (and hence gas demand) even further during peak week periods in order to free-up some pipeline capacity. Such an option would only be feasible if there was other generation capacity elsewhere on the New Zealand electricity system which could replace this lost generation. An indicative simplified analysis suggests that from a generation capacity perspective, this is indeed the case.

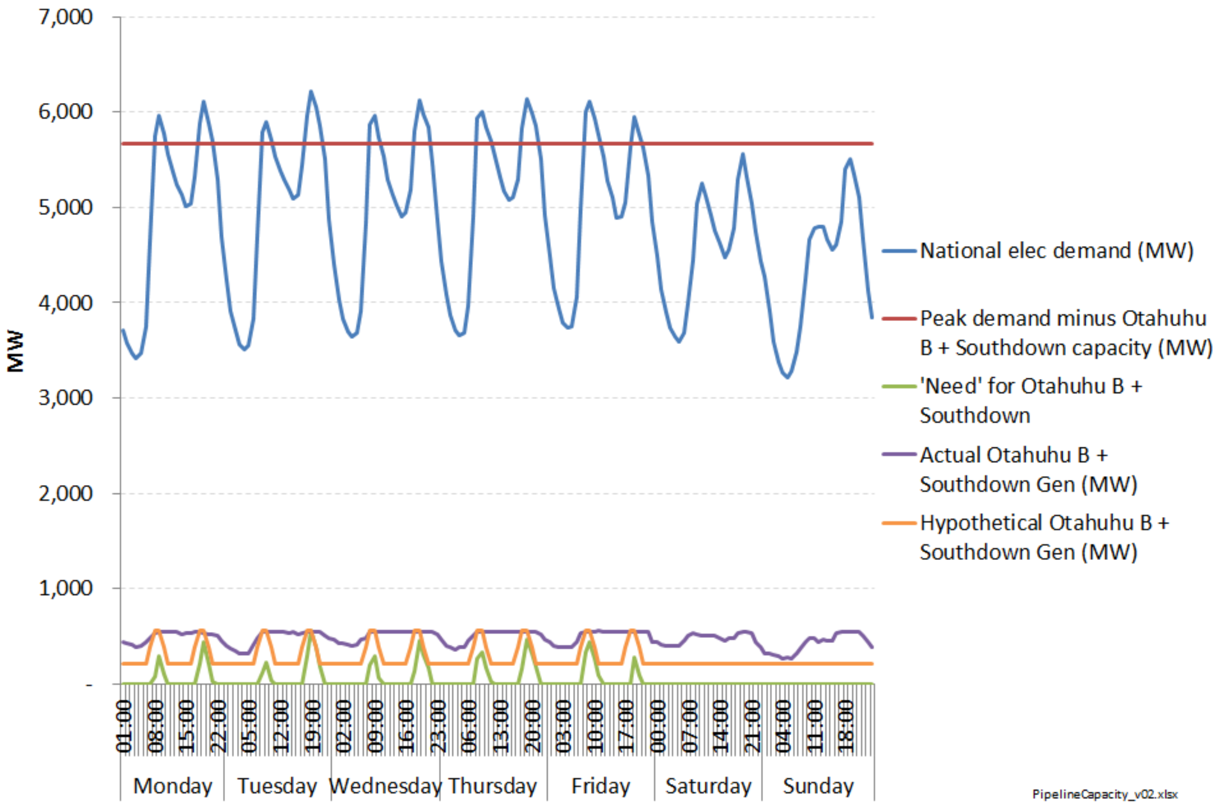
For this analysis it was assumed that there would be a strong correlation between periods of peak gas demand and peak electricity demand. The analysis then looked at the hourly electricity demand during the peak week of gas demand. The (conservative) assumption was made that during the hour of highest demand in this week the electricity system would be running at capacity, and thus could not afford to lose any generation from Otahuhu B and Southdown. However, it was assumed that as demand fell from this level, it would be possible for Otahuhu B and Southdown to similarly scale back.

Figure 64 below shows how national electricity demand varied during the 2010 peak gas week. A horizontal red line is also shown corresponding to the peak electricity demand level minus Otahuhu B + Southdown's capacity. Thus, using the conceptual framework above, when electricity demand rises above this level Otahuhu B + Southdown would be needed by that amount, but when it is below this level they would not be needed.

This level of 'need' is indicated by the bottom green line in the figure – i.e. essentially only operating to meet the morning and evening peaks during the weekdays. For comparison, the purple line shows the actual level of generation by the two Auckland generators which is much higher than this simple level of need. This suggests that there could be significant potential for the Auckland-based generators to reduce their generation at times (for example overnight) during the peak gas weeks to free-up gas pipeline capacity.

If the generators were to follow this line of 'need' in the diagram, the amount of gas capacity that would be freed up would be equal to the area between the purple and the green lines. This would reduce generation (and consequent gas demand) by 85% during the Monday to Friday period.

Figure 64: Simplified analysis of the potential for additional cycling of Auckland generators



However, a number of factors mean that such an approach may over-estimate the potential level of gas demand reduction capable from the power generation sector:

- Start-up costs and minimum generation levels for gas-fired generators; and
- The impact of hydro-generation shortages during dry years.

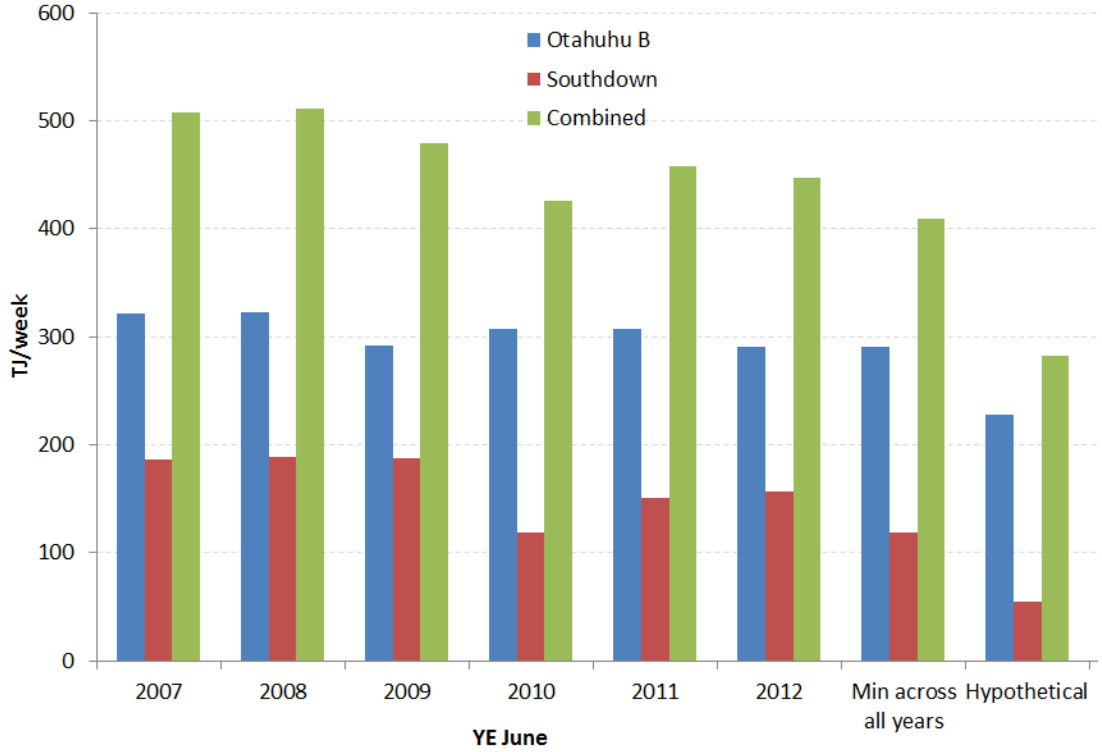
This combination of high start-up costs and minimum generation levels means that it is unlikely that the Auckland generators could operate only during the morning and evening peaks during the weekdays. Instead of shutting-down between these peak periods, it is more likely that they would come down to minimum generation levels.

Accordingly, a hypothetical operating profile was developed which assumed that the generators would operate to maximum levels for two hours over the both the morning and evening peaks, coming down to minimum levels at the other times, and taking an hour to ramp between these levels.

Inspection of historic operating patterns for both such generators indicates that this type of cycling is achievable, and that ramping up- and down in such a fashion has occurred on numerous occasions – although never with such a short peak operating period of only two hours in the morning and two in the evening.

This hypothetical operating pattern is indicated by the orange line on Figure 64. The amount of gas capacity that would be freed up would be equal to the area between the purple and the orange lines. Figure 65 below illustrates the potential scale of reduction in peak week gas consumption by the Auckland-based electricity generators if they were to operate under such a hypothetical operating pattern.

Figure 65: Illustration of potential scale of reduction in peak week gas consumption[63]



PipelineCapacity_v02.xlsx

Based on this hypothetical profile, demand for gas from electricity generators could be 160 TJ/week less than occurred during the 2012 YE June peak week (which occurred in the cold snap of August 2011). By way of a comparison, 160 TJ/week represents 20% of pipeline capacity on the North System.

The analysis on page 94 considers the ability of the electricity system to replace any lost generation from Otahuhu B and Southdown purely from a generating capacity perspective. However, at times of hydro shortage, it is possible that the Auckland-based generators may be needed at all times during the peak gas week, not just during the morning and evening periods of peak demand.

To consider whether this may be the case, a simple analysis was undertaken which compared wholesale electricity prices during the 2008 peak week (which was at the height of one of the most severe hydro shortage periods in the last 15 years), with an inferred value for pipeline capacity at times of peak.

As shown in Figure 66, during the 2008 dry period, electricity prices were generally around $300/MWh, sometimes rising to approximately $500/MWh. In other years with more normal hydrology, prices were lower – typically between the $80 to $120/MWh level[64]. On average, during peak gas week periods, electricity prices have fluctuated between $100/MWh to $380/MWh, and averaged around $160/MWh.

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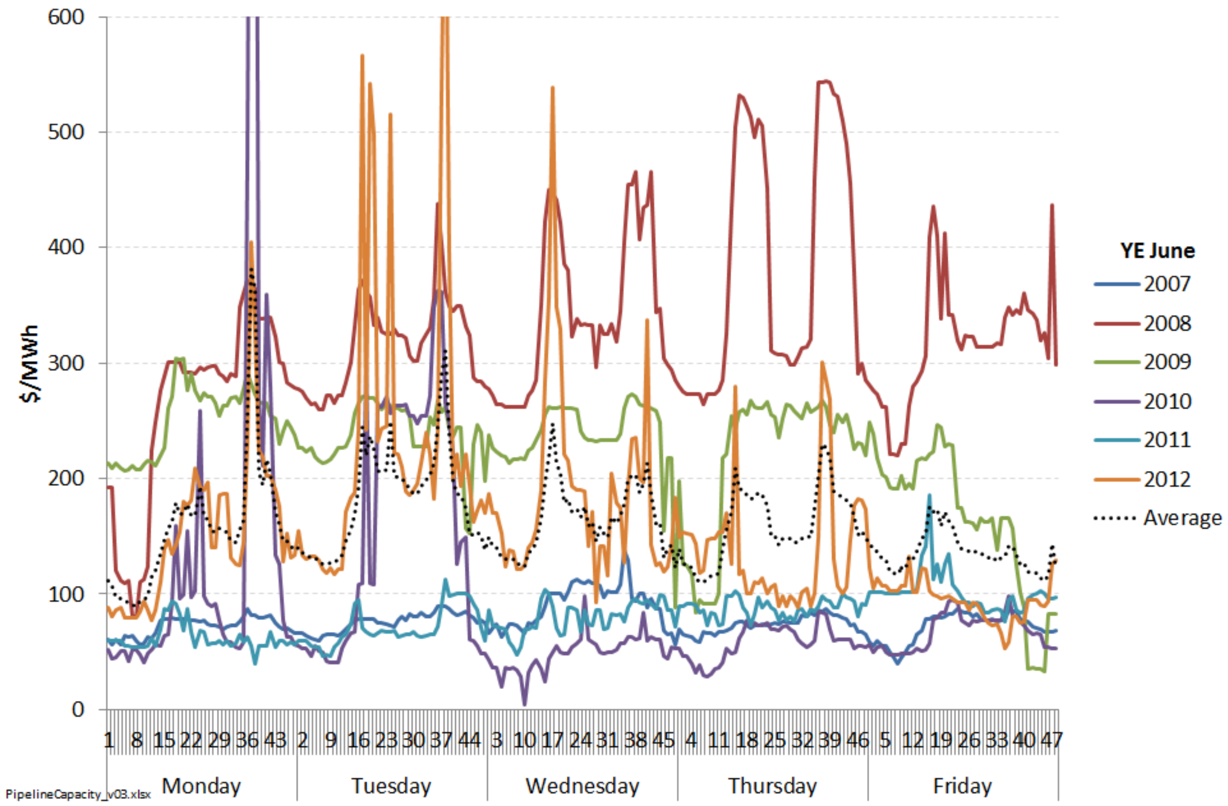
63 The data is organised in years ending June, rather than November as in the rest of the analysis, because it sources data published by Vector in its annual capacity statement which publishes such information on a year ending June basis.

64 It should be noted that the YE June 2009 gas peak week actually occurred in July 2008, when the hydro shortage event was still being experienced.

Figure 66: Wholesale electricity prices at Otahuhu during peak gas weeks



To infer a value for pipeline capacity at times of peak, a simple calculation was undertaken which comprised a number of steps:

- Estimate the annual revenue Vector collects from transmission tariffs on the North System. This was assumed to be broadly representative of the long-run cost of providing pipeline capacity. (i.e. both recovery of operating and capital costs). Based on Vector's published tariffs and information about gas demand on the North System, this annual revenue was estimated to be approximately $55 million.
- Divide this number by the GJ capacity of the pipeline at times of peak. The resulting $/GJ figure can be considered representative of the costs of providing peak capacity[65]. Two calculations were undertaken for the North System:
  - Dividing the annual revenue by peak *day* capacity = $330/GJ
  - Dividing the annual revenue by peak *week* capacity = $66/GJ

[65] It should be caveated that this simple framework assumes that the cost of providing pipeline services is predominantly driven by having sufficient capacity to meet peak demand. This is an over-simplification in that there are other costs driving the provision of pipeline services. However, it is understood that peak demand is the principal driver behind the pipeline investment costs. As such, it is considered that this approach gives a reasonable indication of the scale of costs of providing pipeline services at times of peak.

As a cross-check, these numbers were compared with numbers produced in a 2009 study published by Gas Industry Company[66]. Table 7 of this study, reproduced as Table 4 below, shows estimates of the marginal cost of expansion (MCE) for a number of different pipeline expansion options.

Table 4: Assessment of MCE on Vector transmission network

Pipeline	Delivery point	Description of expansion	Cost ($m)	Inc TJ	MCE ($/GJ/yr)
North	Westfield	Pap East to Smales Rd North loop	26.7	116	23
	Whangarei	Pap East to Smales Rd loop	26.7	16	167
Central North	Morrinsville	Horotiu compression	11.9	42	28
Bay of Plenty	Kinleith	upgrade Pokuru compressor	16.1	24	68
	Gisborne	upgrade Pokuru compressor	16.1	21	77
South	South Tawa	upgrade Kaitoke, loop to Hima	39.8	105	38
	South Hastings	upgrade Kaitoke, loop to Hima	39.8	68	58.5

As can be seen, the estimates produced via the peak week calculation set out above appear reasonable when compared with the MCE values shown in Table 4.

These gas transport costs were added to an assumed gas wholesale price of $10/GJ (which includes an assumed cost of swing for delivering peak gas), and then multiplied by the heat rate of a CCGT, which was assumed to be 7.1 GJ/MWh. The resulting figures were:

- $2,400/MWh when using a peak *day* measure of capacity; and
- $540/MWh when using a peak *week* measure of capacity.

These $/MWh figures represent the required electricity price to justify the use of gas-fired power generation (and thus using up scarce pipeline capacity) during these peak periods.

In other words, if the value of electricity during these peak week periods was higher than this inferred cost of providing gas pipeline capacity, then it would be economically efficient to invest to provide such pipeline capacity. However, as can be seen by comparing the electricity prices in Figure 66 with the above inferred pipeline capacity cost figures, they typically do not reach such levels.

This would tend to imply that it would not be economic to invest in pipeline capacity to enable uninterrupted gas-fired electricity generation during the gas peak week – even to accommodate infrequent dry years.

As such, it would appear that interruption of gas-fired generation would be economic during peak weeks to manage pipeline scarcity issues, even taking into consideration the elevated value of electricity during dry-year periods. Accordingly, any framework for projection of gas demand on the Northern System should consider the potential for increased levels of such interruption.

[66] *"Review of Vector capacity arrangements A research paper"* Creative Energy, January 2009 http://gasindustry.co.nz/sites/default/files/publications/Vector_Capacity_Research_Paper_149282.2.pdf

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However, the extent to which the electricity generators change their behaviour to deliver such altered gas consumption at times of peak will depend on the nature of the contractual relationship they have with Vector for the provision of pipeline services, and the consequent price signals they face. These issues are still being worked through by Gas Industry Company and Vector, and will presumably also require discussions in due course with electricity generators.

Given the inherent uncertainty as to the eventual form of such arrangements, it is not considered that altered gas consumption patterns due to increased interruptibility could be subject to any detailed modelling. Rather, it is considered that a scenario basis be adopted for simulating the level of gas interruption, informed by the analysis described above considering the possible scale of such interruption.

In this respect, while the above analysis has focussed on the potential scale of interruption from electricity generators, it is also considered that some industrial users could deliver interruptible gas through the use of back-up fuel sources or curtailing production in some cases if they faced the price signals to do so.

In the case of switching to back-up fuel, it is considered that it would be economic to switch to burn diesel at ≈ $25/GJ, rather than incurring gas pipeline and wholesale costs of approximately $76/GJ as calculated above.

However, little quantitative information is available to enable firm estimates of the scale of this potential. Qualitatively, one industrial stakeholder who was installing diesel back-up capabilities following the Maui pipeline outage suggested that it was a relatively inexpensive investment. However, another suggested that the nature of their process meant it was harder to achieve.

Similarly, there was a mix of views as to the ease / cost of interrupting production for their different processes. Some indicated that their sites did have potential, whereas others indicated that the cost would be too great.

This variability in the responsiveness of different consumers to price signals is consistent with observed outcomes from directly-connected electricity consumers following the introduction of regional coincident peak demand charging for electricity transmission. Some consumers have been observed to radically reduce their consumption at times of peak (by more than 90%) following the introduction of this charging approach, while others have shown relatively little change to their consumption patterns.

Given this lack of firm data, simple assumptions have been made as to the potential for interruption from the other sectors. Thus it is assumed that these other industrial sectors could reduce peak week consumption by 15% (through a mixture of switching to diesel and interrupting processes) except for the Non-TOU, Dairy and Refining sectors where it is assumed that no potential for interruption (or *further* interruption in the case of Refining[67]) exists.

To illustrate the potential impact of interruption from the power generation and other industrial sectors on peak week demand, Figure 67 below shows simple projections of peak week demand for the different supply scenarios for the North sector.

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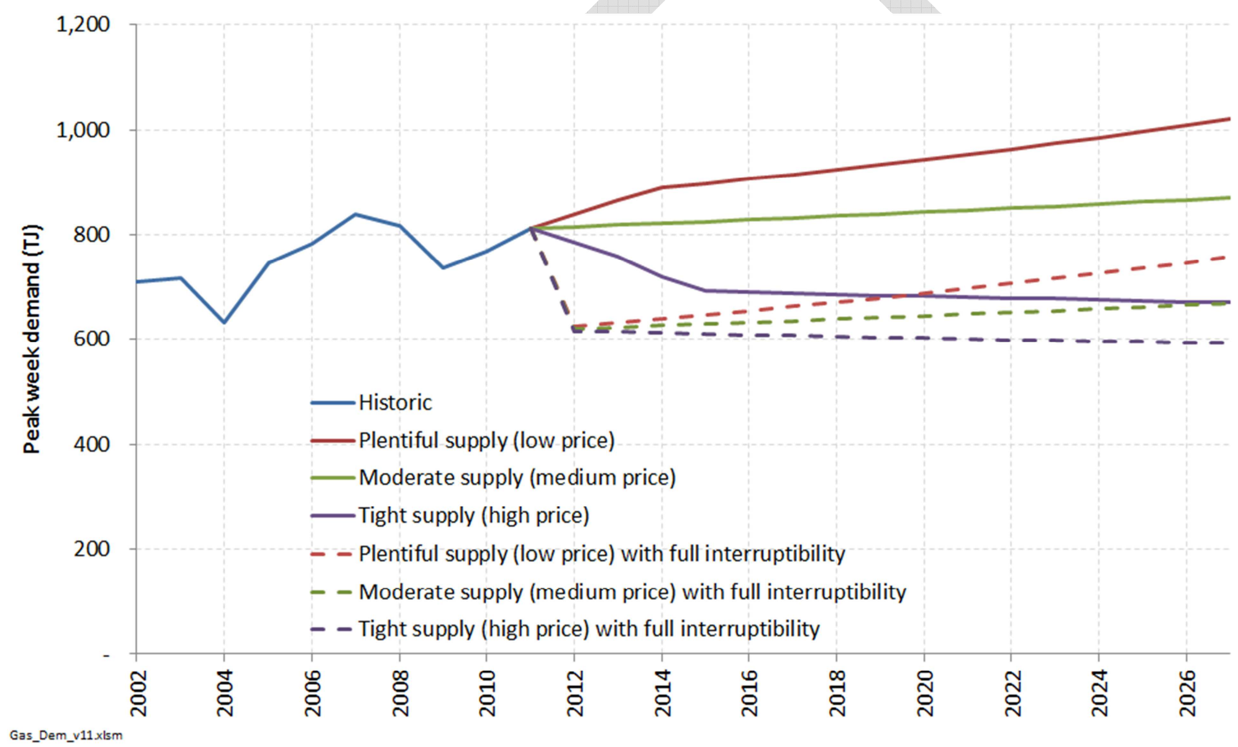
67 The refinery already has an interruptible contract with Vector. It is assumed that the maximum amount of interruption would have been called during the 2011 peak week incident.

The methodology for the projection is simple in that it takes observed 2011 peak week demand for each of the sectors and grows such demand based on a factor relating to the projection of annual demand for that sector for the relevant price scenario.

This simple approach has been adopted rather than use the complex statistical modelling approach described above because it is an illustration of the impact of interruption which necessarily requires the use of gross assumptions. Coupled with the inherent uncertainty associated with the projections of annual demand, the combined scale of uncertainty would swamp any accuracy achieved by seeking to project un-interrupted peak demand using a sophisticated statistical approach.

For each sector, this peak week demand is then factored downwards by the percentages described above for each sector, except for electricity generation in the North sector, where the level of generation is assumed to be at the 'hypothetical' minimum profile level set out above. Thus for each supply scenario, there are two projections: with and without interruption.

Figure 67: Projections of Vector North system peak week demand (with and without interruption) for different supply scenarios



Given that peak week demand in 2011 was at the limit of the North System pipeline capacity, Figure 67 appears to indicate that demand growth in the low and medium gas price scenarios would be at a level which would breach pipeline capacity if no new interruption capability were brought forward.

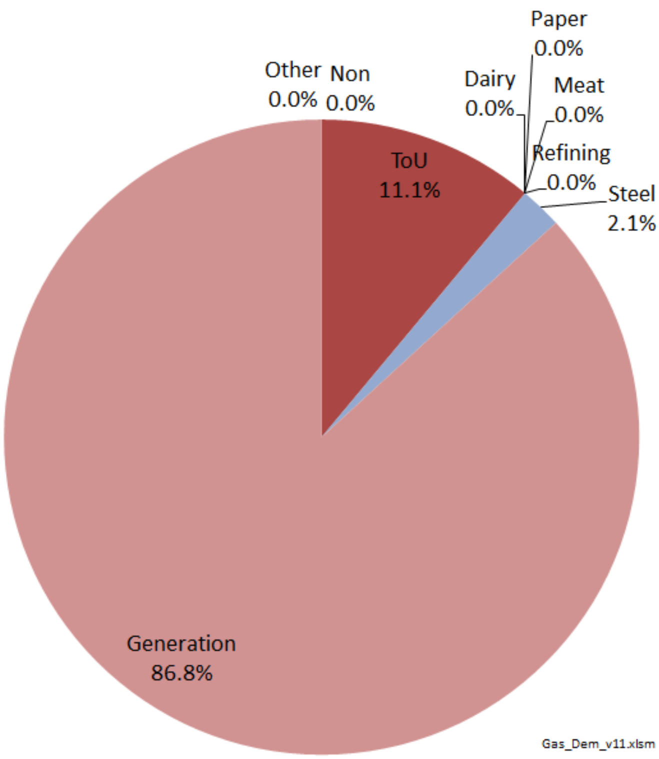
Given that available pipeline capacity is a hard constraint, and if there was no investment to upgrade the pipeline, it is likely that Vector would need to prevent potential new loads from connecting to the network. Indeed, a number of industrial stakeholders suggested that they had been prevented from connecting due to unavailable pipeline capacity.

However, Figure 67 shows that if the full extent of assumed interruptibility from the different gas consumers were called upon, then new demand growth could easily be accommodated without the need for pipeline investment for at least the next 15 years.

While the level of interruption shown is based on the relatively simple analysis described above, the scale of potential is such that only a relatively small fraction of this potential needs to be realised in order to relieve the pipeline constraint.

Figure 68 below shows the breakdown of this assumed interruptible potential among the different sectors.

Figure 68: Breakdown of assumed interruptible potential for Vector North system



For this potential to be realised would require changes to the pipeline pricing and access regimes in order to send efficient price signals at times of peak demand. The means by which such changes could be effected is beyond the scope of this study. However, this study does appear to indicate that relief of pipeline congestion in the North system through altered pricing and access arrangements would be a worthwhile achievement.

A further factor to consider from a pipeline investment perspective is the potential closure or reconfiguration of the largest point demand on the North system – namely the Otahuhu B CCGT. This is something that Contact Energy considered for 2014 in relation to the CCGT's mid-life maintenance.

Contact was considering removing its steam turbine capability and converting Otahuhu B to operate solely in open-cycle mode. Had this occurred, this would have materially reduced the station's gas consumption requirements during peak weeks due to the much more flexible mode of operation that OCGTs can perform relative to CCGTs. In particular incurring much lower start-up costs, and being able to operate at lower min-gen levels.

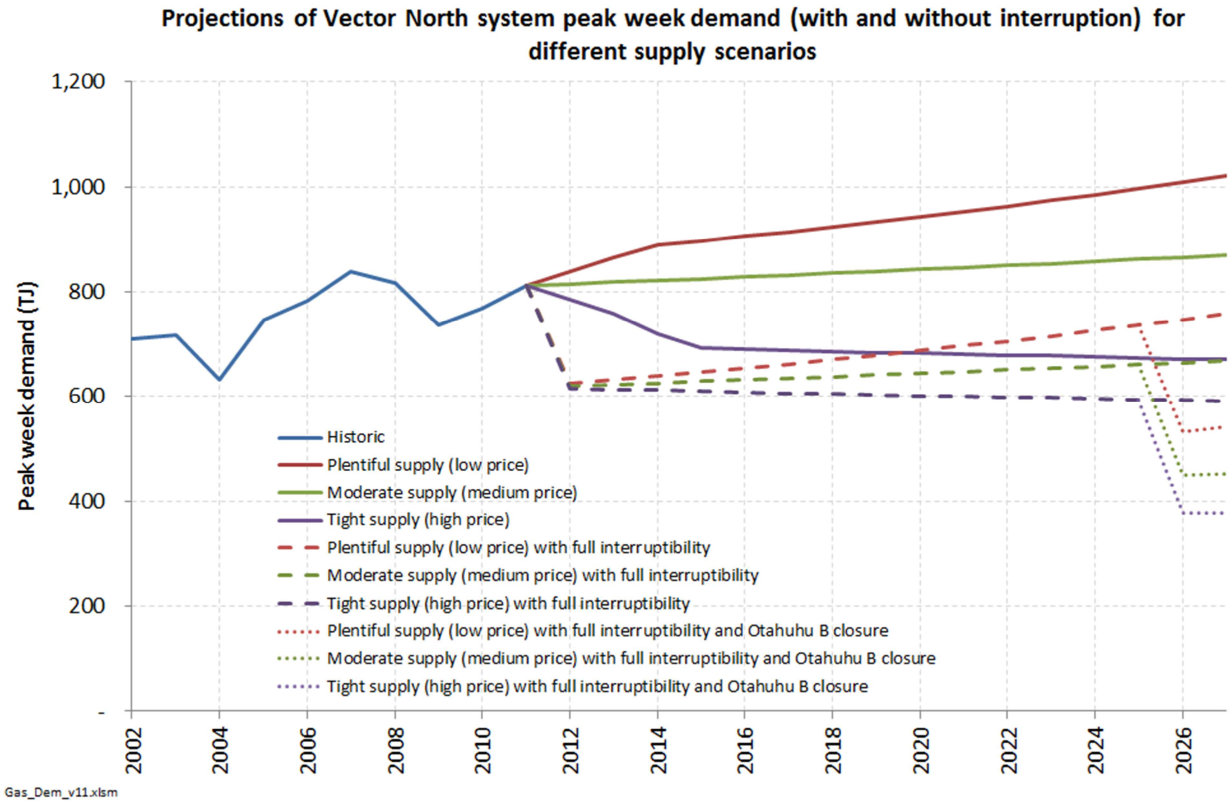
Such a re-configuration is now not going to happen in the short- to medium-term as Contact has recently announced it is committed to re-investing in Otahuhu B such that it will continue to operate as a CCGT.

However, it is something that could happen towards the tail end of this study's projection period as Otahuhu B will be close to the end of its economic life. It is highly conceivable that Otahuhu B could cease operation in the latter half of the 2020s.

Were such a closure to occur, it is highly conceivable that it would not be replaced by a CCGT in Auckland, but could instead be replaced by an OCGT to help manage peak demand requirements in the Auckland region.

In order to get a feel for the implications of such an outcome, Figure 62 shows how peak week demand could be affected by the closure of Otahuhu B in 2026, and its replacement with a 225MW peaker which only operates for six hours each day during the morning and evening peaks during the gas peak week.

Figure 69: Projections of Vector North system peak week demand (with and without interruption and with closure of Otahuhu B) for different supply scenarios



Source: Concept estimates

As can be seen, were Otahuhu B to close, there would certainly be no need for pipeline investment in the North system.

Appendix A. Description of statistical model

Due to the inherent variability of demand driven by factors such as the weather, and 'natural' randomness in the coincident level of demand from consumers, this necessarily requires the ability to consider the probabilities of peak demand reaching certain levels, and thus be able to estimate what a 1-in-20 year or 1-in-50 year level of peak demand would be. This exercise has some key inherent challenges:

- There is only a limited historical gas demand data set (just over ten years), meaning that just considering this data alone would make it hard to infer what a 1-in-50 year peak demand, say, might look like;
- There is a need to be able to consider peak demand over different lengths of time, ranging from a day through to a week, given that the critical time-period for different pipelines can vary;
- Different demand sectors exhibit different seasonal and diurnal patterns, and different temperature sensitivities, yet the proportions of these different sectors has varied during the historic data series, and is likely to vary further into the future.

To address these issues, a statistical model was developed which sought to determine the relationship between demand and key observable drivers (namely temperature and temporal parameters (for example day of week, month of year, public holidays)).

Figure 70 below shows how different sectors exhibit different degrees of seasonal and diurnal variation.

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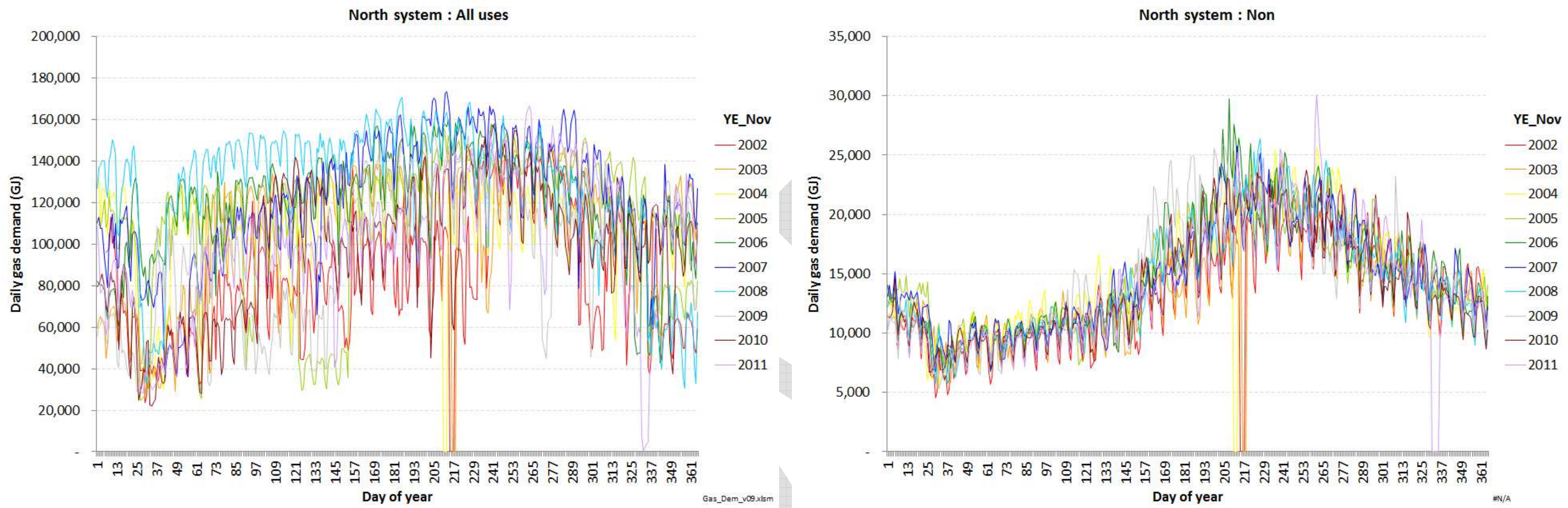
Figure 70: Examples of different patterns of seasonal and diurnal demand for different sectors in the North System[68]



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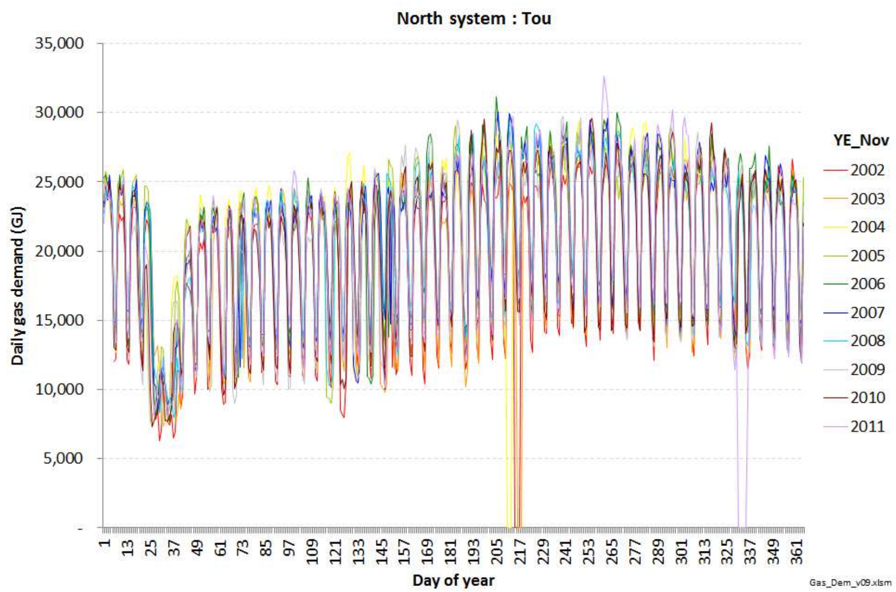
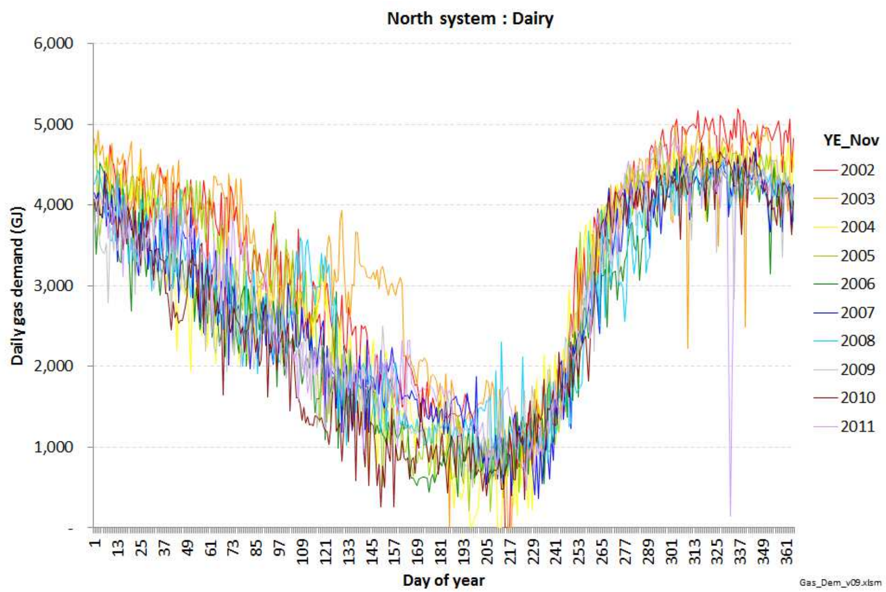
68 For this year ending November representation, Day 1 = 1st December, and Christmas = Day 25.


North system : Tou
Daily gas demand (GJ)
Day of year
YE_Nov
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
Gas_Dem_v09.xlsm


North system : Dairy
Daily gas demand (GJ)
Day of year
YE_Nov
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
Gas_Dem_v09.xlsm

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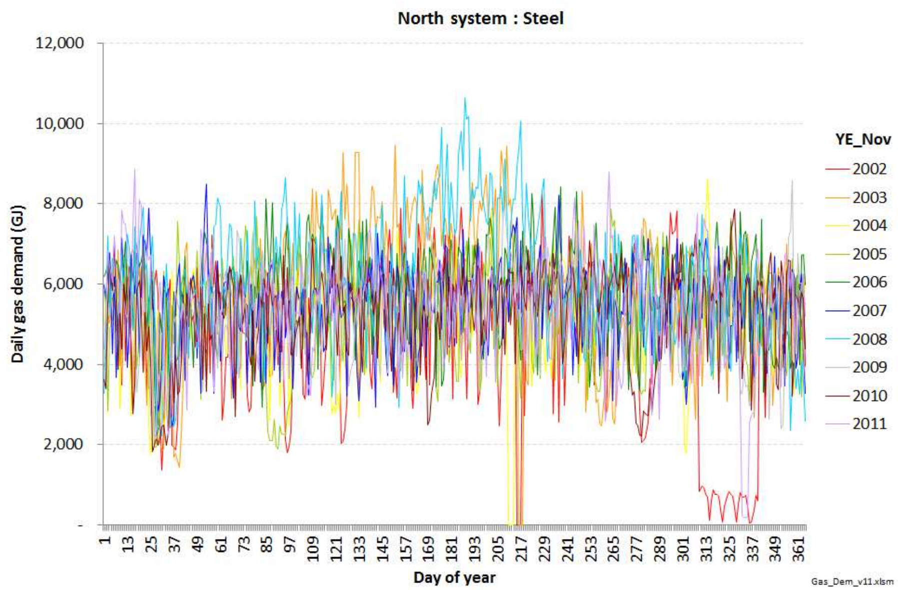
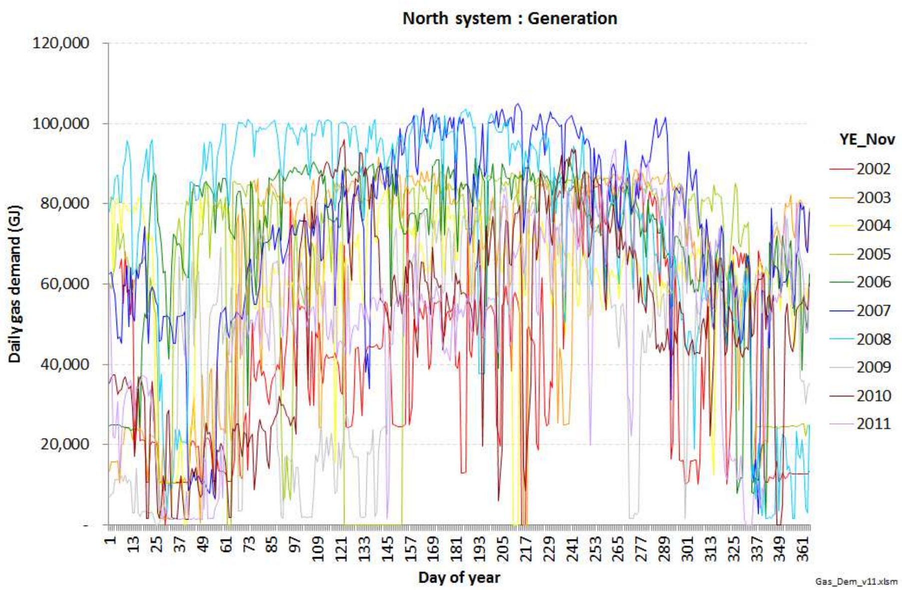

North system : Steel
Daily gas demand (GJ)
12,000
10,000
8,000
6,000
4,000
2,000
-
Day of year
YE_Nov
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
Gas_Dem_v11.xlsm


North system : Generation
Daily gas demand (GJ)
120,000
100,000
80,000
60,000
40,000
20,000
-
Day of year
YE_Nov
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
Gas_Dem_v11.xlsm

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As can be seen, mass-market customers (represented by the 'Non' time-of use category) have a strong seasonal pattern to their consumption driven by the space heating requirement in winter.

Dairy customers also have a very strong seasonal pattern to their consumption. However, unlike mass-market customers, this is not driven by winter-temperatures for space heating, but rather the seasonal variation of cows producing milk. As it happens, this tends to mean that dairy users have a counter-cyclical consumption profile, such that their proportionate contribution to the system peak is much less than their proportionate contribution to overall annual demand.

General business customers (as represented by the 'ToU' category) have a strong weekday / weekend pattern to their consumption, but with less of a seasonal variation – apart from a significant reduction in consumption during the Christmas holiday period. This is because of their work patterns, and the fact that the majority of their gas requirement is for process heat which is not affected by temperature.

The steel sector (represented by the Glenbrook steel mill) shows quite a degree of random variation, presumably relating to the continual cycle of production runs. Despite, or perhaps because of, this randomness, its consumption record is well suited to statistical analysis to consider the likelihood of different levels of gas consumption.

The power generation sector, on the other hand, does not appear to be well suited to the type of statistical analysis that would be appropriate for the other sectors. This is because the gas-fired power generation outcomes observed during the past ten years are due to a range of factors including changes in wholesale fuel prices, swing fuel prices, fuel contracts, CO2 prices, electricity transmission constraints, and the variability in other forms of generation (particularly hydrology and more recently wind).

Many of these factors experienced material changes during the course of the last ten years, and are projected to undertake even more significant changes in the following decade. This will greatly reduce the relevance of statistical analysis of the last ten years' outcomes as a means of considering potential outcomes for the next ten years.

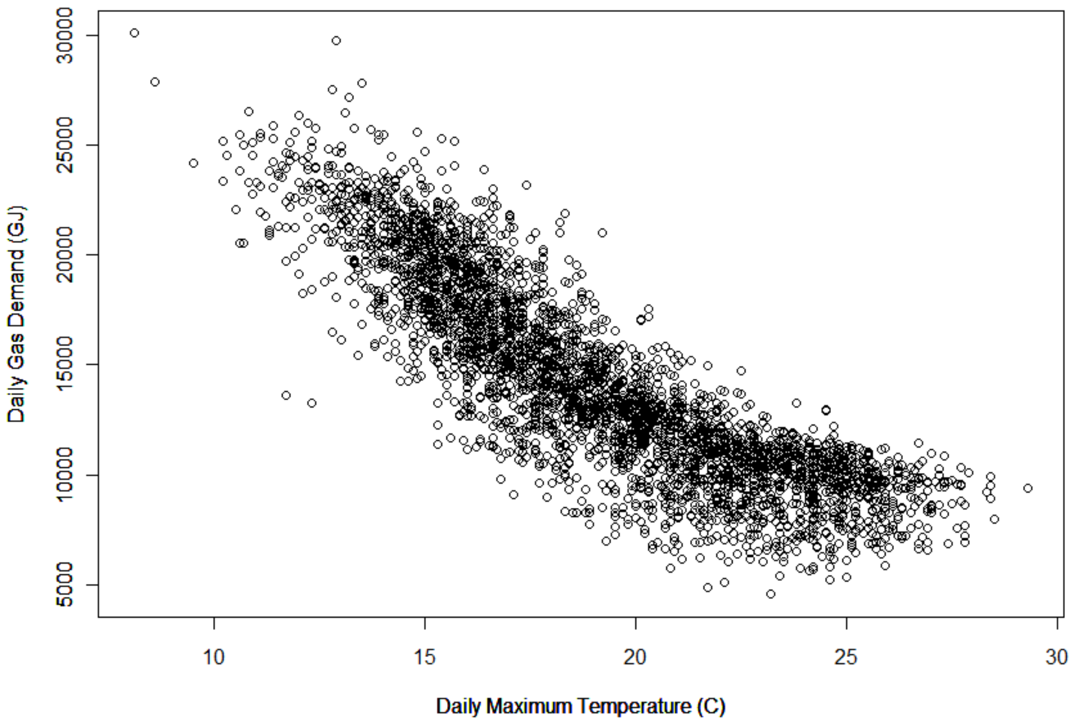
In addition, as set out in more detail in section 4.2, it is considered that the electricity generation sector probably has the greatest potential to economically respond to altered price signals to reduce consumption during the relatively infrequent times of pipeline congestion.

Given all of the above, no statistical analysis was performed on the generation sector.

With respect to sensitivity to temperature, the issue is that space heating demand can vary significantly with the weather, and the weather itself can vary significantly from year-to-year. Thus, peak heating demand in a year with a particular severe cold snap can be significantly higher than in a relatively mild year. This makes it challenging to project peak demand, and means that any projections must be made with reference to a particular probability of weather-severity. For example, a 1-in-20 year peak demand means the demand that would be expected during a weather event whose severity would only be expected once every 20 years.

To illustrate the sensitivity of demand to weather, Figure 71 below shows how Non-ToU demand varies with temperature for the North system[69].

Figure 71: Relationship between Non-ToU demand in the North system and temperature



Source: Concept analysis

As can be seen, as temperature drops, Non-Tou demand increases. However, some sectors exhibit little or no temperature sensitivity to demand due to the fact that their gas is used for industrial processes rather than space heating. This is illustrated in Figure 72 below which shows that demand for gas for Steel manufacture has little correlation with temperature.

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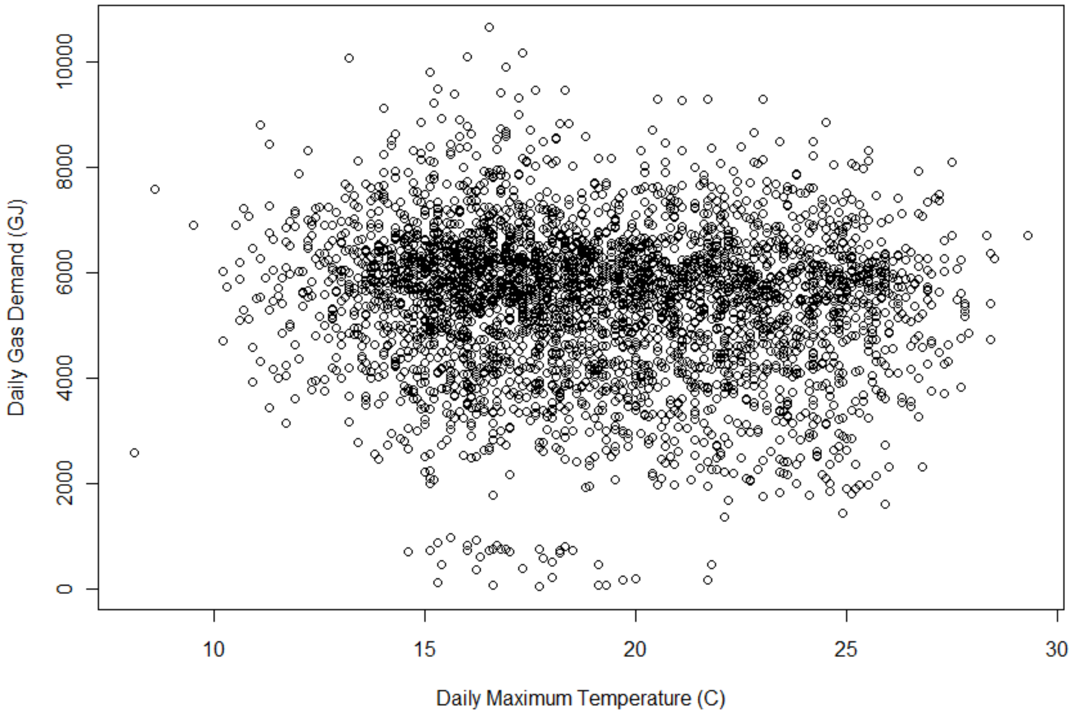
[69] Slightly counter-intuitively, it was discovered that demand was better correlated with daily *maximum* temperature rather than daily minimum temperature. This could be because a large proportion of heating occurs during the day and evening, and maximum temperatures are likely to be a better proxy for day / evening temperatures than minimum temperatures (which are most likely to occur in the early hours of the morning).

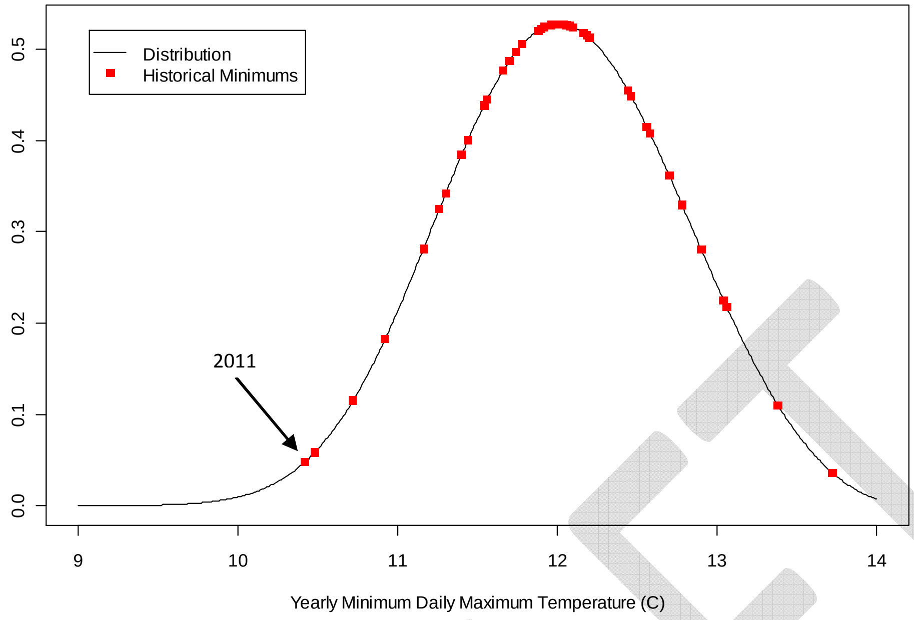
Figure 72: Relationship between gas demand for the Steel sector in the North system and temperature



Source: Concept analysis

As an aside, the analysis also revealed that the cold snap of the week of 15-19 Aug 2011 (and associated gas demand peak) really was unusual. On a rolling 5 day maximum temperature basis, the weather during 15-19 August was ≈ a 1 in 95 year event (using 46 years' worth of temperature data, and a Generalised Extreme Value (GEV) probability distribution approach). This is illustrated in Figure 73 below.

Figure 73: Distribution of annual minimum values for rolling 5 day maximum temperatures



Given that different sectors exhibit different seasonal and diurnal patterns in demand, and differing levels of temperature sensitivity, the key problem in determining what a 1-in-20 or 1-in-50 peak gas demand might look like is that:

- There is only a limited historical gas demand data set (just over ten years). Thus, looking at this data alone would make it hard to infer what a 1-in-50 year peak demand, say, might look like; and
- The relative proportions of different gas sectors has changed over this time (for example the proportion of Tou versus Dairy, say).

To address both of these issues, plus the issue of different sectors exhibiting different seasonal and diurnal variations in demand, a statistical model was developed which sought to determine the relationship between temperature and key temporal paramters (for example day of week, month of year, public holidays).

This model was based on ten years' worth of historical daily gas demand and ambient temperature data, and considered each of the different sectors separately. i.e. a statistical relationship was developed for the Non-ToU sector, the ToU sector, and each of the sectors such as Meat, Dairy, etc.

The model is a linear regression model, implemented in the R programming language. It sought to determine the best algorithm which could be used to explain observed demand when linked to observed other factors (such as temperature, day-of-week, etc.).

This algorithm could then be fed a more comprehensive set of historic daily temperature data to enable development of a more comprehensive set of possible demand futures for each demand sector.

The model is expressed as:

Daily demand =

Coefficient varying from year to year **+**	*Trend component*
Coefficient depending on month, day of week, and public holiday or not **+**	*Cyclic component*
Quadratic function of today's maximum temperature* **+** Quadratic function of tomorrow's maximum temperature* **+**	*Temperature component (if applicable)*
Whatever is left	*Residual component*

** or 18 degrees, whichever is less. Demand does not tend to increase further past this point*

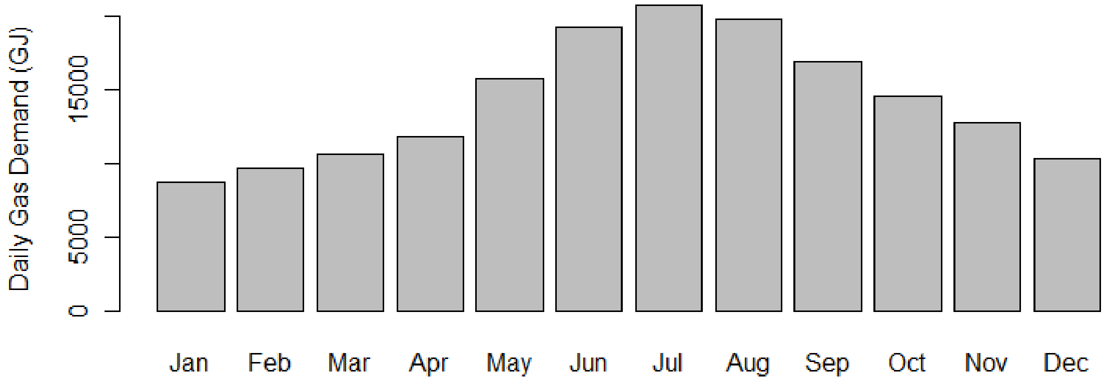
This model was selected from a reasonably wide pool of alternatives on the basis of good explanatory power + simplicity. For instance we considered min temperature rather than max, and yesterday's temperature rather than tomorrow's, but neither was an improvement. In both cases this is probably because heating needs are driven largely by evening temperatures, which are more correlated with the following day than the previous day, and more likely correlated with the maximum demand during the day than the minimum demand during the night.

Here is an example of how the decomposition works for non-ToU demand in the North system.

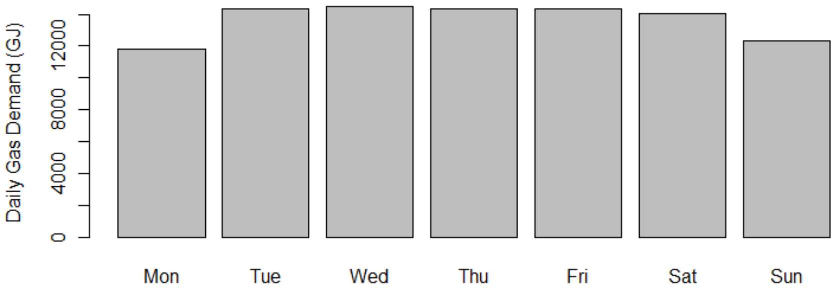
Here is the *trend component* (showing little trend over time, but a possibly anomalous value for 2002). This trend component is required to effectively normalise the data to account for changing overall quantities of demand over time due to changing numbers of consumers on the network.

The *cyclic component* is harder to show because it's made up of 168 values – 12 months of the year x 7 days of the week x (weekday or not). However, here are some summaries of it.

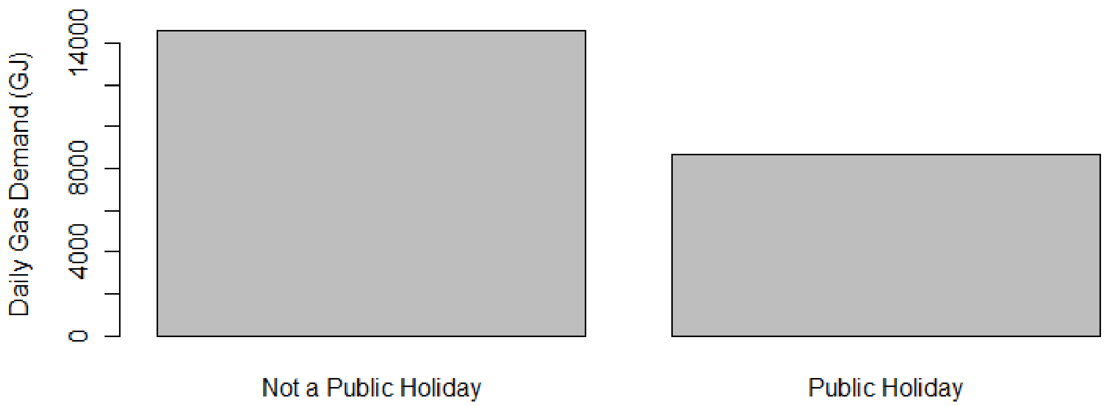
Looking just at months, we see demand being highest in winter, driven by increased space heating requirements in the winter months.



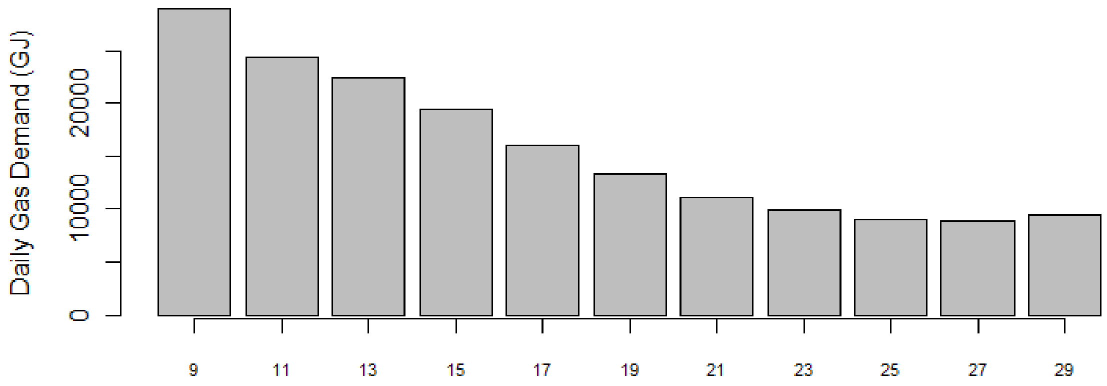
The model allows the shape over the week to vary from month to month. However, looking across all months, we see demand being highest on weekdays (as one would expect):



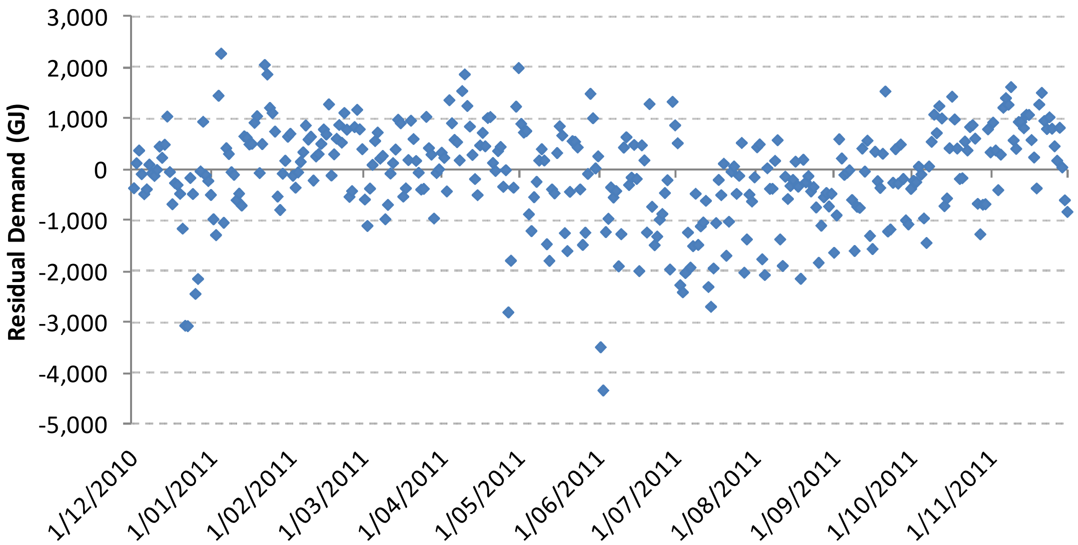
And naturally demand is low on public holidays.



The *temperature* component is demonstrated in the plot below:



After all these components have been stripped out, only the *residual* component remains which represents that element of observed demand which cannot be explained by the other factors, and characterises the random variation that will occur 'naturally'. This is largely noise, with a small amount of day-to-day correlation.



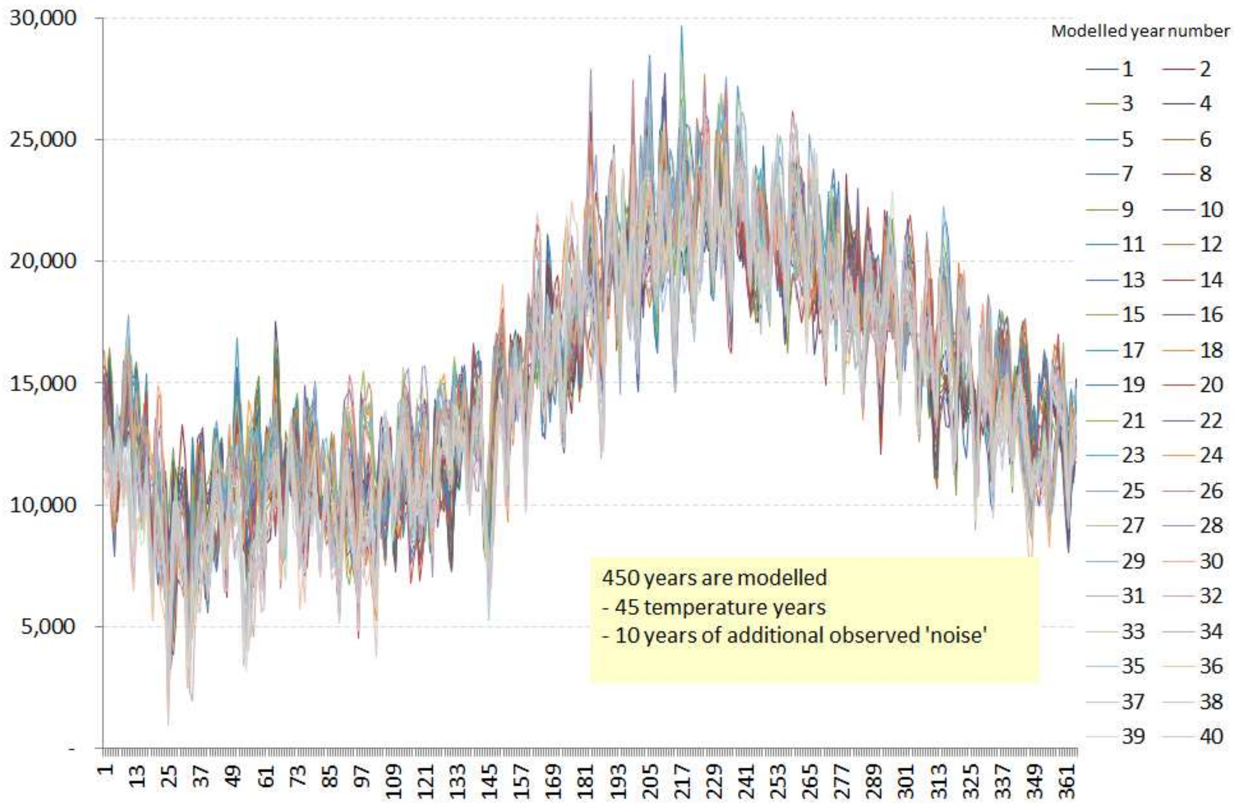
A statistical model was developed for each demand sector for each geographic region. For the major industrial sectors (i.e. all sectors apart from the Non-TOU and TOU sectors), no correlation with temperature was observed. Accordingly, for such sectors, no temperature component has been included in the statistical model.

Once the statistical relationships had been determined, for those sectors for which a material sensitivity to temperature had been established (only the Non-TOU and TOU sectors), the model was then fed 45 years' worth of historical daily temperature data. This produced daily demand projections of what gas demand would likely have been like for each of these 45 years for each of the sectors. In fact, for each of these 45 historic 'temperature years', *ten* yearly demand projections were produced due to the observed 'noise' in the ten years' worth of historic data which can't be exactly explained by temperature or temporal dependencies, but are representative of the random variations in demand that will naturally occur.

For the sectors which didn't have any material sensitivity to temperature, only ten years of daily demand projections were produced, based on the temporal drivers determined in the model and factored by the 'noise' observed in the ten years of historical data.

Figure 74 below shows an illustration of one such set of projections for one sector.

Figure 74: Example projections of daily Non-ToU demand for the North System for a sub-set of possible future years[70]

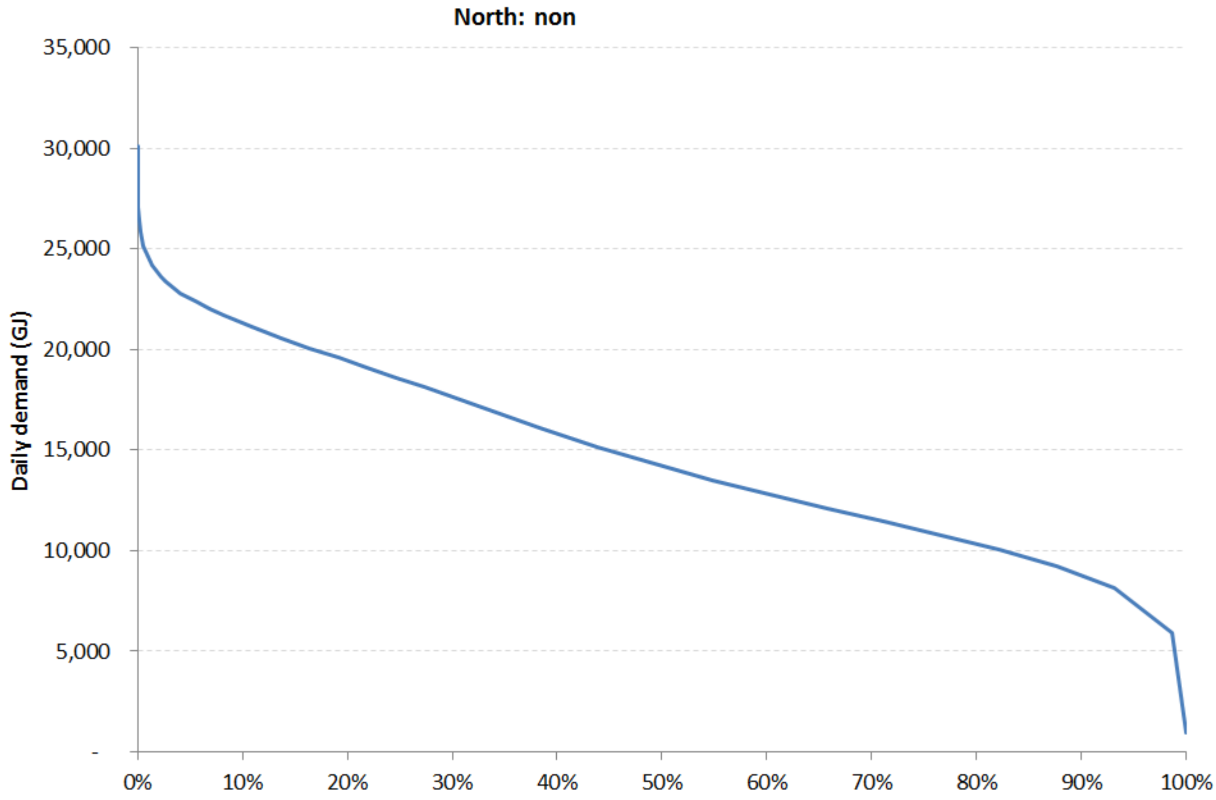


With these 450 modelled years' worth of data it is possible to get better insights into the variability of gas demand for the different sectors, and the probabilities of different levels of peak demand.

For example, Figure 75 below illustrates that the Non-TOU sector has a few days of extreme peak demand.

70 For ease of illustration, only 40 daily profiles are shown in this graph. In reality, 450 profiles are produced by the model, corresponding to the 45 historical temperature years, combined with each of the ten 'residual' years for which historical data exists.

Figure 75: Duration curve of modelled gas demand for Non-ToU sector for North system over a 45 year time-frame

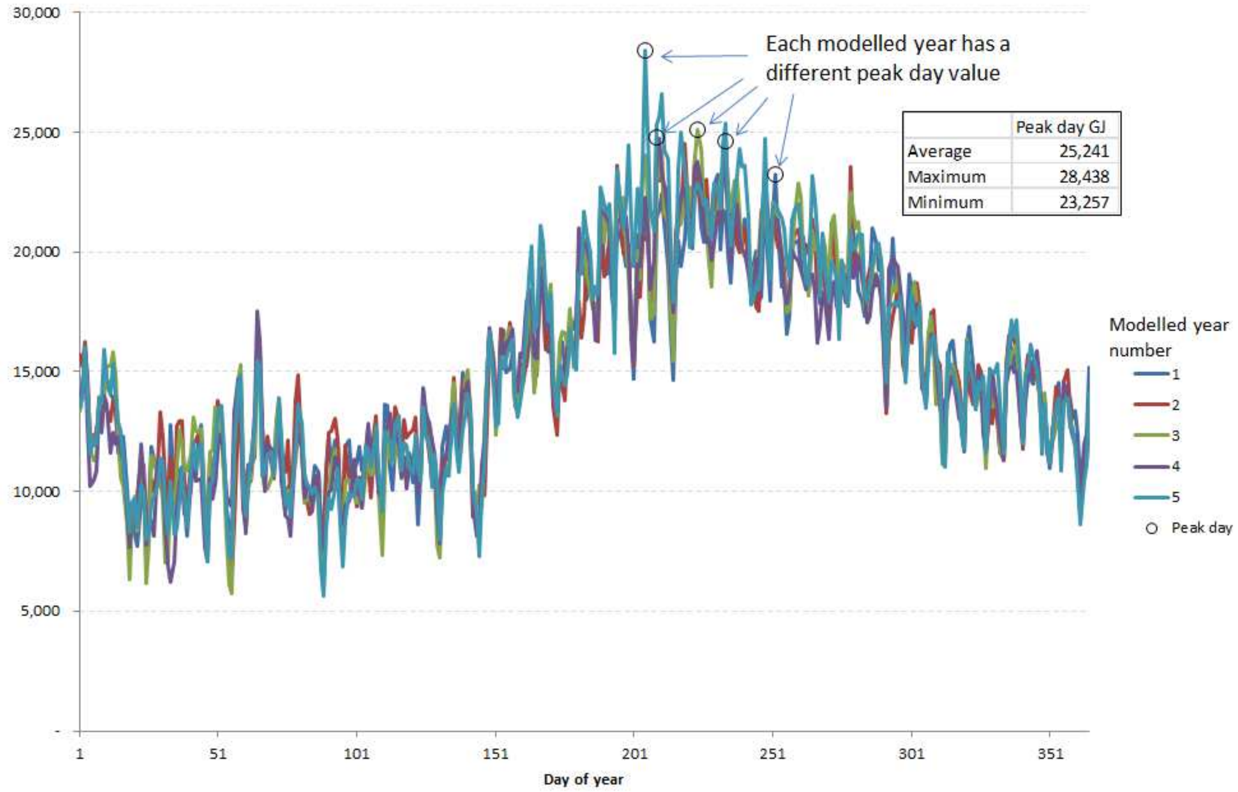


It is also possible to get analysis on the *likelihood* of a particular level of peak demand being observed in a year.

To illustrate this Figure 76 below shows just five daily projected demand profiles from the model. (Noting that 450 demand profiles would be produced for a temperature-sensitive sector, and 10 for a non-temperature sensitive sector).

For each of these five profiles, the peak day demands have been circled. As the text box in the diagram shows, the average of these five peak days is 25,241 GJ, the maximum is 28,438 GJ and the minimum is 23,257 GJ. Thus, if only these five profiles were available, the 1-in-5 year peak demand would be approximately 28,438 GJ, and the mean peak demand would be 25,241 GJ. Of course, with greater numbers of demand profiles than 5, it is possible to derive more statistically significant peak demand probabilities.

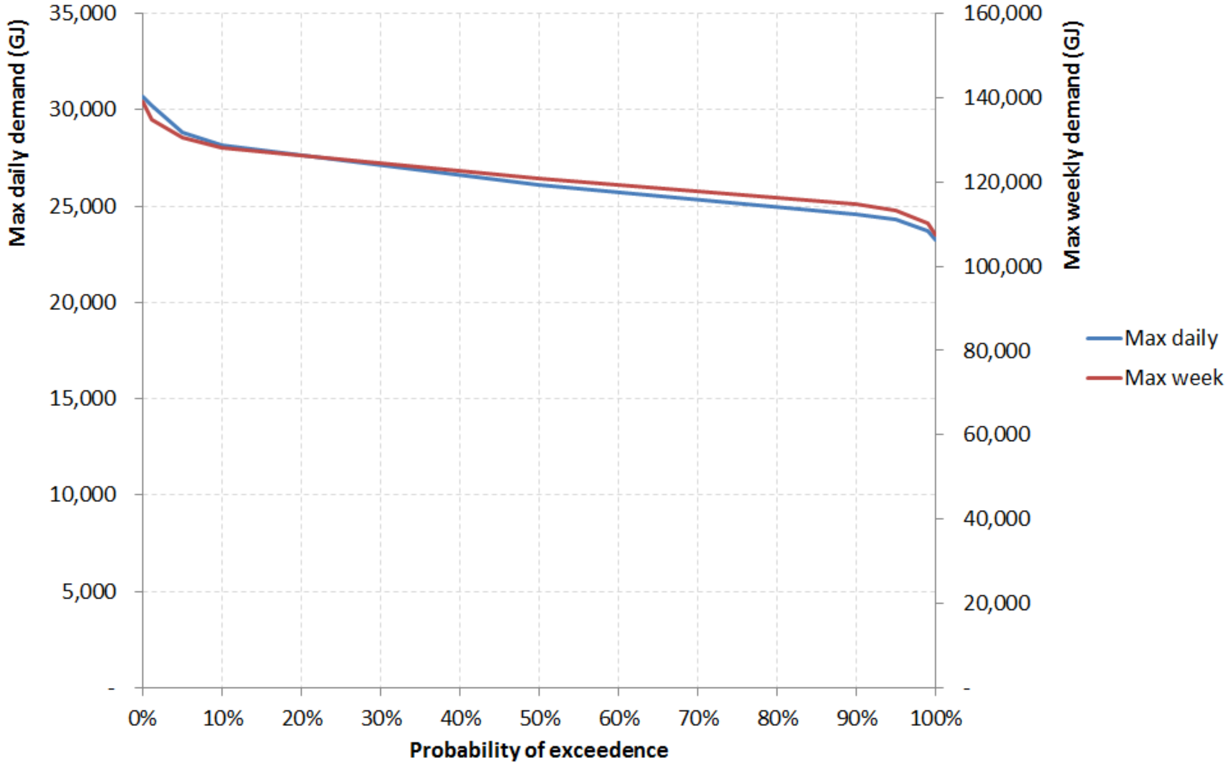
Figure 76: Illustration of derivation of peak demand levels



It is also possible to use such daily demand profiles to calculate peak week demands and the probabilities of differing levels of peak week demands using the same approach as described above.

Figure 77 below illustrates the probabilities of differing levels of peak day and peak week demands based on the statistical output from the model for one particular sector.

Figure 77: Example of probabilities of differing levels of peak day and peak week demand for the Non-TOU sector for the North system for 2012



The last aspect of the model seeks to project total system peak demand across all sectors. As illustrated earlier in Table 3 on page 77, it is considered that different sectors are likely to exhibit different rates of demand growth going forward for the different price scenarios.

For a given price scenario and given year in the future, the model takes the projected annual demand for each sector and produces the 450 or 10 daily demand projections such that the average of all the projections for each sector equals the projected annual demand for that sector. These individual sector demand projections are then summed, but ensuring that internal consistency is maintained such that temperature years are added consistently (i.e. temperature year 6 for the Non-TOU sector is only added to temperature year 6 for the TOU sector), and the ten residual 'noise' years are added consistently (i.e. residual year 3 for each sector is only added to residual year 3 for the other sectors).

This enables overall projections of peak day and peak week pipeline demand for each system with calculations of the probabilities of exceedance for the underlying assumptions relating to annual demand for each sector[71].

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[71] Although, as stated in the main body of this report, this analysis makes no consideration of the potential for changes in consumer behaviour at times of peak demand due to changes in the design of pipeline pricing and access arrangements. As section 4.2 sets out, it is considered that potential changes to pipeline pricing and access arrangements could materially change behaviour at peak for most sectors, and would thus materially alter the probabilities of exceedance calculated using the modelled approach as described above.

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Appendix B. Glossary

$	NZ dollars, unless otherwise stated.
°C	Degrees Celsius
1P reserves	Estimated quantities of gas that are reasonably certain to be recoverable in future under existing economic and operating conditions. A low-side estimate also known as proved gas reserves.
2P reserves	The best estimate of commercially recoverable reserves. Often used as the basis for reports to share markets, gas contracts, and project economic justification. The sum of proved-plus-probable estimates of gas reserves.
3P reserves	The sum of proved, probable, and possible estimates of gas reserves.
Baseload power station	A power station that generally operates at a near-constant level of output over time. See also peaking power station and mid-merit power station.
bbl	Barrel – a legacy volume measure of 42 US gallons or ~159 litres.
bbl/d	Barrels per day
bopd	Barrels of oil per day
Capacity factor	A measure of the actual level of output for a generator relative to its output at maximum capacity.
Capex	Capital expenditure
CO2	Carbon dioxide
Combined-cycle gas turbine (CCGT)	A device utilising a gas turbine and heat recovery/steam generation to efficiently generate electricity. More capital intensive than open-cycle gas turbines and therefore expected to be highly utilised. See also open-cycle gas turbine.
Conventional gas	Gas that is produced using conventional or traditional oil and gas industry practices. See also unconventional gas.
CSG (coal seam gas)	Where methane is stored in coal seams of low permeability (also known as coal bed methane).
EDGS	Electricity Demand and Generation Scenarios prepared by MBIE.

EECA	Energy Efficiency and Conservation Authority
FLNG	Floating LNG
FSRU	Floating storage and regasification unit
GDP	Gross Domestic Product
GJ	Gigajoule: a unit of energy measurement equal to 10^9 joules
GWh	Gigawatt-hour: a unit of energy measurement equal to 10^9 watt-hours
Horizontal drilling	A process of drilling non-vertical wells.
Hydraulic fracturing	A means of natural gas extraction involving the fracturing of a rock layer using high-pressure fluids, in order to release trapped gases.
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
km	Kilometre
Linepack	The pressurised volume of gas stored in a pipeline system.
Liquefied natural gas (LNG)	Natural gas that has been converted into liquid form for ease of storage or transport.
Liquid Petroleum Gas (LPG)	A mixture of light hydrocarbon gases, primarily propane and butane, that are liquid at a relatively low pressure/high temperature compared to natural gas. See also natural gas.
Load factor (l.f)	A measure of the average level of demand relative to the peak level of demand.
LRMC	Long-run marginal cost
Mass-market	A segment of the gas market defined to include residential users and non-TOU businesses.
MBIE	Ministry of Business, Innovation & Employment
Mid-merit power station	A power station that operates on a basis in between baseload and peaking power stations. See also baseload power station and peaking power station.

mmbbl	1 million barrels of oil
MW	Megawatt: a unit of power measurement equal to 10^6 watts
MWh	Megawatt hour: a unit of energy measurement equal to 10^6 watt-hours
MWth	Megawatts of thermal capacity. 1 MWth is approximately equal to 1000 kg steam/hour.
NAAN	North Auckland and Northland grid upgrade
Natural gas	A naturally occurring hydrocarbon gas mixture consisting primarily of methane.
NI	North Island
NIGUP	North Island Grid Upgrade Proposal
NZEC	New Zealand Energy Corp
Open-cycle gas turbine (OCGT)	A device utilising a gas turbine to generate electricity. Less efficient and less capital intensive than combined-cycle gas turbine (CCGT) and therefore often used only to satisfy peak electricity demand.
Original Oil in Place (OOIP)	The total commercial production potential of an oil reservoir.
Opex	Operating expenditure
P10	A forecast that has a 10% probability of exceedance (POE).
P50	A forecast that has a 50% probability of exceedance (POE).
Peak day	Over the course of a year, the day on which maximum gas demand occurs.
Peak week	Over the course of a year, the week during which maximum gas demand occurs.
Peaking power stations	A power station that generally operates infrequently, usually at times of high demand. See also baseload power station and mid-merit power station.
Possible reserves	Estimated quantities that have a chance of being discovered under favourable circumstances. 'Possible, proved, and probable' reserves added together make up 3P reserves.

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Probability of exceedance (POE)	Refers to the probability that a forecast figure will be exceeded. For example, a forecast 10% POE maximum annual demand figure will, on average, be exceeded only in 1 year in every 10 years.
Probable reserves	Estimated quantities of gas that have a reasonable probability of being produced under existing economic and operating conditions. Proved-plus-probable reserves added together make up 2P reserves.
Proved reserves	Estimated quantities of gas that are reasonably certain to be recoverable in future under existing economic and operating conditions. Also known as 1P reserves.
PJ	Petajoule: unit of energy measurement equal to 10^{15} joules.
PJ/yr	Petajoules per year: a unit of gas consumed, produced or transported in one year.
Reserves	Gas resources that are considered to be commercially recoverable and have been approved or justified for commercial development.
Reserves cover ratio/ Reserves to production ratio	A quantity, expressed in years, that is the ratio of remaining reserves divided by the current rate of production. A nearly depleted gas basin may have a low R/P ratio (for example 5 years) whereas a newly discovered or very large basin in the early years of its producing life may have a high R/P ratio (for example 20 years). Increasing the estimated reserves increases the R/P ratio, whereas increasing the production rate decreases the R/P ratio.
Reservoir	In geology, a naturally occurring storage area that traps and holds oil and/or gas.
RMA	Resource Management Act
Shale gas	Where gas is trapped in shale deposits, made up of thin layers of fine-grained sedimentary rock, typically found in river deltas, lake deposits or floodplains.
Swing	Variation in the rate of gas consumed (up or down), to meet changing demand or other needs.
Swing factor	The ability provided in a contract for the user to vary the rate of gas delivery up and down, to meet changing daily demand or other needs. The swing factor is defined as (maximum daily quantity x 365) / annual quantity.
STOS	Shell Todd Oil Services

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t	tonne
tCO2	tonne of carbon dioxide
TGP	Teeside Gas Port
Time-of-Use (ToU)	A time-of-use customer has an electricity or gas meter (also known as a smart-meter) that can measure consumption at regular intervals – usually each half hour. Generally applies to larger commercial or industrial consumers.
TJ	Terajoules: unit of energy measurement equal to 10^{12} joules.
TJ/d or TJ/wk	Terajoules per day/week: a unit of gas consumed, produced or transported in one day/week.
Tx	Transmission
UCG (underground coal gasification)	Where an underground combustion process is used to convert coal into methane, hydrogen, carbon monoxide (and other products), which are then extracted from wells drilled into the coal seam.
Unconventional gas	Gas found in coal seams, shale layers, or tightly compacted sandstone that cannot be economically produced using conventional oil and gas industry techniques. See also conventional gas.
Well-head gas price	The price of gas excluding any costs for transmission, swing, taxes etc.

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