Gas for electricity generation: availability and price forecasts

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14 April 2009

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Executive summary

The Commission has revised the gas availability and price assumptions that feed into the Commission's Generation Expansion Model. Gas forecasts have been obtained by first estimating the depletion of the existing reserve and then a Monte Carlo simulation has been performed to forecast gas production from future discoveries. Production forecasts have been developed for five future gas supply scenarios.

The simulations suggest that production will rise in the next couple of years, to be followed by a drop from 2013 to 2018 caused by the production lead time of any new potential discoveries. Even in the highest gas production scenario, production is expected to decline to 150 PJ.

As the price is clearly linked to the fuel availability, five price forecasts have been derived. The historical industrial gas price seems to correlate with the net gas production, and an exponential relationship which provides a reasonable fit to the data has been used to obtain the gas price forecasts for the shorter term. This relationship has been adjusted to mitigate price extremes with a floor and ceiling price of $NZ3/GJ and $NZ13/GJ respectively. The ceiling price is reached in all the scenarios by 2020.

Longer term gas price forecasts have been obtained on the basis that if New Zealand enters a low or high gas production phase there will be an incentive to respectively buy or sell gas overseas. LNG is the cheapest option to transport natural gas over long distances, especially as is the case of New Zealand, transborder pipelines is not an option. International LNG markets have developed rapidly in the last decade or so. International LNG prices are generally on the rise and are usually closely related to oil prices and if indigenous natural gas reserves continue to fall, New Zealand could import natural gas to fill the gap, and would therefore be exposed to the international LNG price. On the other hand, if large quantities of gas were found in New Zealand, the field owners would have the incentive to export the natural gas to seek higher prices and therefore the domestic gas price could be set to the international LNG price, minus the liquefaction, shipping and regasification costs. In this situation the domestic price will also be very vulnerable to the international LNG price and the $US/$NZ exchange rate.

The information contained in this report might be used in developing the generation scenarios for the next SOO. Feedback from interested parties is welcomed.

Disclaimer

The analysis contained in this report has been undertaken at a high level using a broad set of assumptions. It is important to note that this report is only one source of information on the matters discussed, and differing views may be held on the material and conclusions set out. Anyone considering or making decisions on these matters, or on any aspect of them, must make their own enquiries and form their own views based on all the information and advice available to them.

To the fullest extent permitted by law, the Electricity Commission does not accept any liability for any view, information, error or omission in this report.

This report is current as at the date of its publication only, and will not necessarily be updated to reflect any changes in circumstances or Electricity Commission views.

Glossary of abbreviations and terms

Bcf	Billion cubic feet
Bcm	Billion cubic meter
CAE	New Zealand Centre for Advanced Engineering
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CEE	Center for Energy Economics
Commission	Electricity Commission
Gas	Natural gas
GEM	Generation Expansion Model
GJ	Gigajoule (10^9 Joules)
GPAs	Grid Planning Assumptions
GWh	Gigawatt hour
IEA	International Energy Agency
LNG	Liquefied Natural Gas
LRMC	Long Run Marginal Cost
MED	Ministry of Economic Development
MBtu	Million British thermal unit
MW	Megawatt
MWh	Megawatt hour
OCGT	Open Cycle Gas Turbine
PJ	Petajoule (10^{15} Joules)
SRMC	Short Run Marginal Cost
SOO	Statement of Opportunities

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1. Introduction and purpose of this report

The Electricity Commission (Commission) is required to publish a Statement of Opportunities (SOO) as part of its duties in overseeing aspects of transmission investment (rule 9 of section III of part F of the Electricity Governance Rules 2003). Under rule 9.1.1.2, the SOO must include the Grid Planning Assumptions (GPAs). The GPAs must include a reasonable range of credible future, high-level generation scenarios (rule 10.3.1.3).

The 2008 SOO scenarios included, amongst other things, assumptions on future supply and price of natural gas (Commission, 2008a). Four out of the five scenarios assumed that 75 PJ/year is available, while for the high gas scenario, 120 PJ/year is assumed available for electricity generation. Gas prices vary from one scenario to another, and range from $NZ5/GJ to $NZ13/GJ in the 75 PJ/year scenarios, and up to $NZ8/GJ in the high gas discovery scenario.

The objective of this report is to present revised forecasts of the availability and price of gas for electricity generation. The Commission believes that the assumptions used to develop the SOO scenarios were sensible at the time, but that further work could improve the validity of the production and price forecasts, especially over the shorter term. The forecasts will obviously become more speculative in nature over the more distant future.

The Commission has revised the two current production paths (75 and 120 PJ/year), and has developed five production forecasts (i.e. very low, low, medium, high, very high). As price is generally linked to fuel availability, especially for non-renewable resources, five price forecasts have been derived from the production forecasts.

The Commission will formally consult on this work when the next GPAs are developed, as this information could form part of the next SOO. In the meantime, feedback from interested parties is welcome.

2. Background and methodology

Natural gas is a finite fossil fuel that is inevitably subject to depletion when extracted. Depletion refers to the reduction of the reserve. The reserve is the quantity of the resource that can be recovered under prevailing economic and technical conditions. The reserve (in PJ) is often expressed as 1P (90% certainty), 2P (50% certainty), or 3P (10% certainty), also known as proven, probable and possible reserves. Throughout this document, the reserve values are given as 2P reserves. The total reserve is the sum of all producing or yet to be developed fields. All current fields are located in the Taranaki region. Table 1 presents the August 2008 gas field reserves.

Table 1: Field reserves as at January 2008

Field name	PJ
Maui	489.6
Kapuni	239.4
Pohokura	1063.6
Kaimiro/Ngatoro	30.8
Tariki/Ahuroa	22.5
Waihapa/Ngaere	0
Rimu	53.9
Mckee	54
Kupe	266.5
Mangahewa	80.7
Others	160.1
Total	**2461.1**

Source: Ministry of Economic Development, *New Zealand energy in brief*, August 2008

Gas production refers to the quantity of gas extracted. The Ministry of Economic Development (MED) publishes on a regular basis the past production by field (MED, June 2008). Net gas production (usually measured in energy content, PJ) is the difference between gas production and the amount of gas flared, gas re-injected, LPG extracted, own use and losses. For this particular work, the Commission was interested in the quantity of gas that would eventually reach consumers, and therefore net gas production was used. In this document the term ‘production’ is used loosely to refer to net gas production. Net gas production in 2007 was 165 PJ, which means that at this production rate, the reserve would be depleted in 14 years.

Gas availability and price forecasts have been prepared as follows:

1. The proportion of each field reserve that will be extracted for each year was estimated by fitting the historical production and extending the profile out to 2050. For each field the sum of yearly forecasted production from 2008 to 2050 is equal to its reserve (Table 1).
2. A Monte Carlo simulation has been performed to model new gas discoveries. One sample represents the sum of 20 production profiles which have been randomly created. 50,000 samples have been obtained to obtain stable statistics. The 10th, 30th, 50th, 70th and 90th percentile have been selected to represent the five production forecasts, namely very low, low, medium, high and very high production forecasts.

3. The gas production forecasts give the total energy available for all sectors. It is necessary to determine the gas available for electricity generation only, as this is the value required by the Commission's Generation Expansion Model (GEM).
4. The relationship between historical quarterly gas price and production level has been estimated and applied to the five production forecasts. This relationship is only valid over the sort term (and even then is somewhat ad hoc).
5. For the long term, gas price forecast assumptions around potential import/export of natural gas were made.

3. Depletion of the existing gas reserve

A clear pattern emerges when looking at most of the historical production profiles: a bell shape which is more or less skewed to the right, i.e. having the right tail of the distribution longer than the left. This is in agreement with the Hubbert peak theory which proposed that fossil fuel production in a given region over time would follow a roughly bell-shaped curve[1]. Maui and Waihapa net gas production profiles (blue stars) are shown as examples in Figure 1 and Figure 2 respectively. At first the production rises quickly. Then peak output is reached with the maximum production depending on the field's reserve. Production begins to decline following an approximate exponential decline. A reasonable representation of the natural gas production, which appears to follow a "pulse" profile, is given by equation (1):

$$y = A\left(1 - e^{-\left(\frac{x-x_0}{t_1}\right)}\right)^P e^{-\left(\frac{x-x_0}{t_2}\right)} \qquad (1)$$

where
y is the net gas production per annum,
x denotes years,
A is a shift parameter of the peak production,
t_1 and t_2 are parameters controlling the width of the bell shape,
x_0 is the first production year, and
P is a parameter influencing how quickly the peak production is reached.

The black lines in Figure 1 and Figure 2 show the pulse fits for Maui and Waihapa production, respectively. It can be seen that it provides a reasonable fit, especially in the first years of the field development when production increases quickly. The majority of the

[1] http://en.wikipedia.org/wiki/Hubbert_peak_theory

production profiles of the fields presented in Table 1 appear to follow the pulse profile. However, some of them, such as the Kapuni field, had atypical depletion profile with a very sharp peak production in the early years, followed by a slow rise over 20 years (see Figure 3). In this situation the left side of the pulse profile does not provide a good fit, but the right hand side has still been used to forecast the depletion of the reserve.

The depletion of the reserve was obtained by selecting the best fit for each individual historical production field and matching its respective reserve (see Figure 4). Finally, the production forecast of each field has been added together to obtain the overall New Zealand gas depletion profile out to 2050. Figure 1 and Figure 3 provide examples where the black lines are the best fit of historical production extended out to 2050, and the black area represents the remaining Maui (489 PJ) and Kapuni (239 PJ) reserves, respectively.

Figure 1: Maui field production

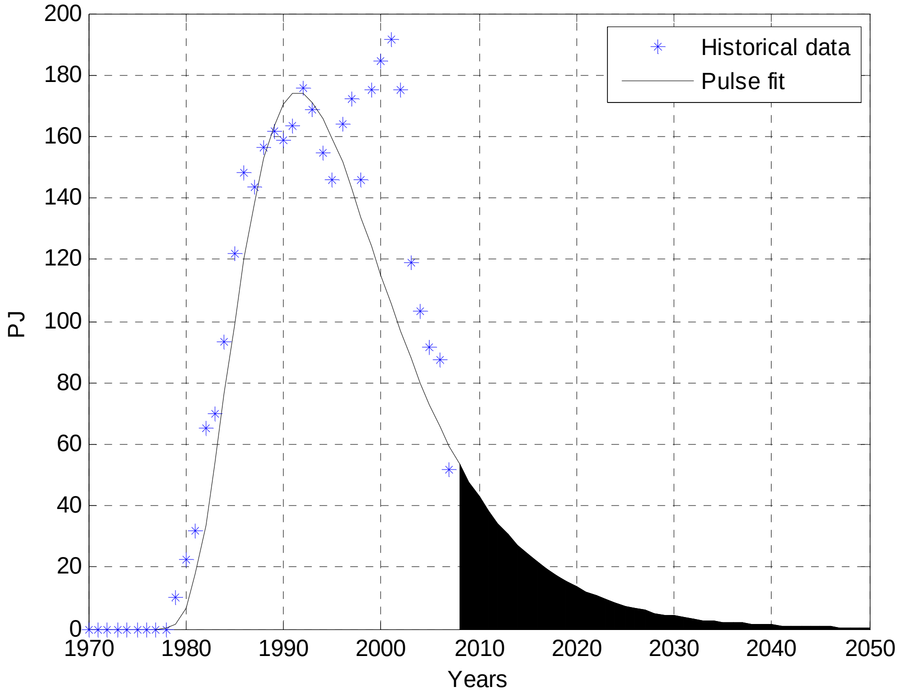


Figure 2: Waihapa field production

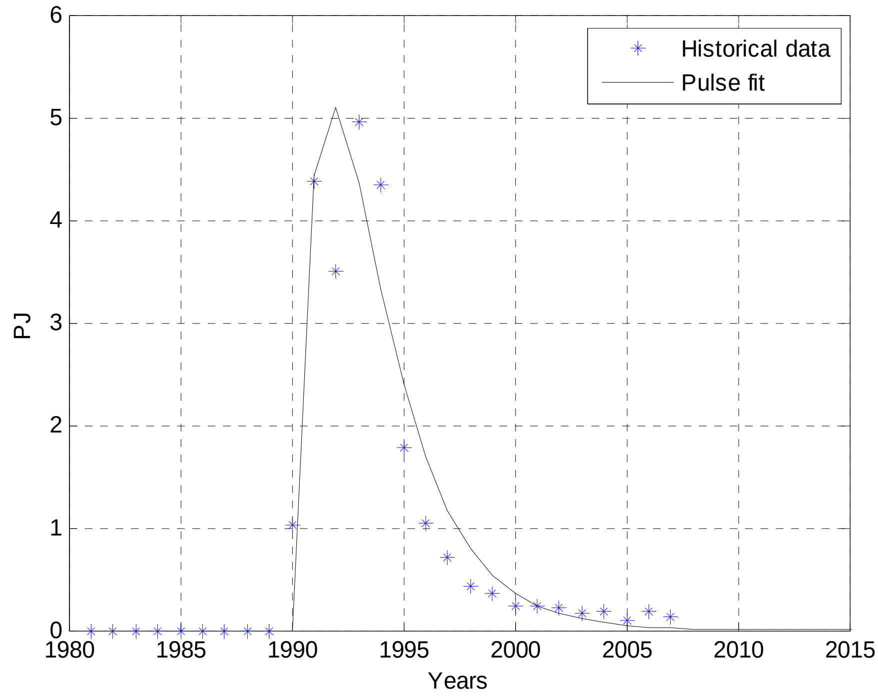
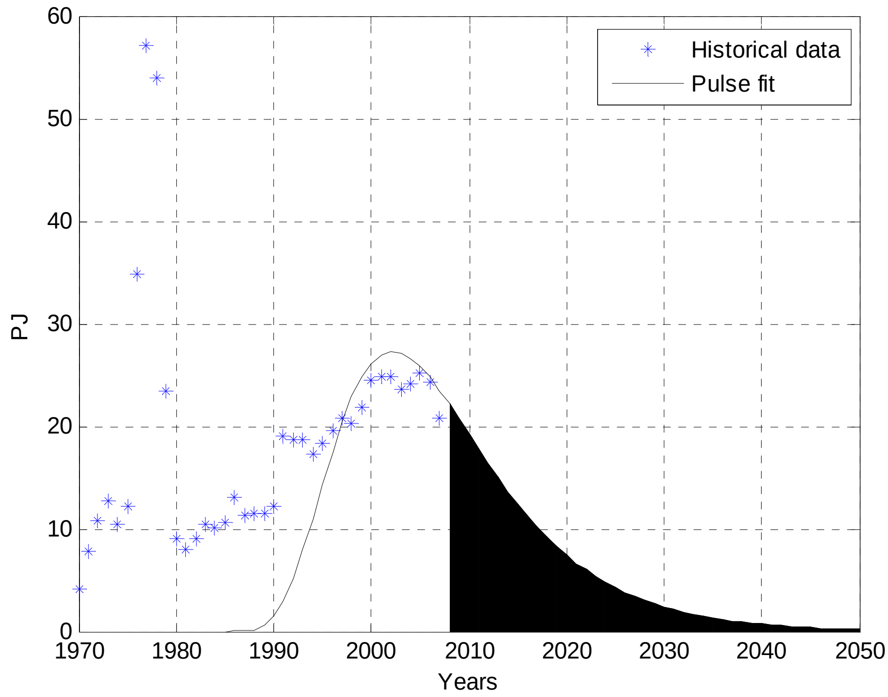
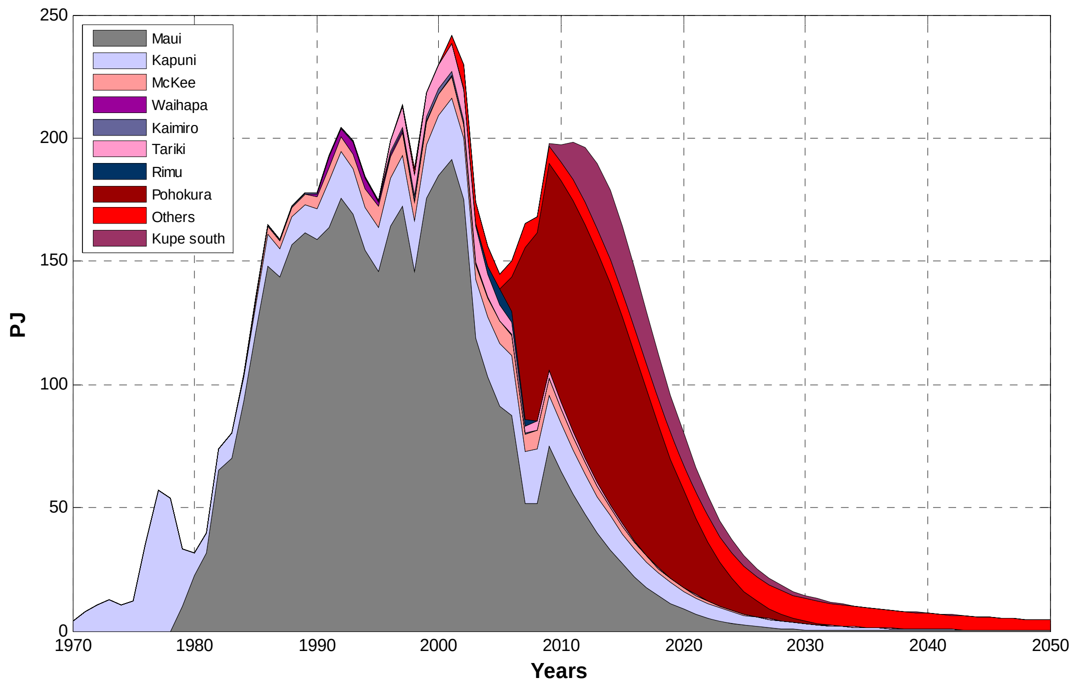


Figure 3: Kapuni field production



In 2007, Methanex announced it intended restarting one of the two Motunui 900,000 tonne per year production trains for a few years. This decision seems to have been made on the basis that the short term gas availability looks optimistic, and that the international methanol price had almost tripled since the Motunui plant was closed in 2004 (McDouall, 2008). Methanex and the field producers' incentive is to extract the gas out of the field as quickly as possible to take advantage of the current high methanol and oil prices. Methanex restarted the plant in early October 2008. Because Methanex is a large user, it is necessary to adjust the depletion to account for this additional substantial demand. It was assumed here that Methanex would use 40 PJ per annum up to 2013 and therefore the production is expected to reach approximately 200 PJ in 2009 and stay around this level until 2013.

Figure 4: Depletion of existing fields



Notes: the red area named 'others' includes Kaimiro/Ngatoro, Tariki/Ahuroa, Rimu, Mangahewa and others of Table 1

4. Gas production forecasts

A Monte Carlo simulation has been used to simulate future gas discoveries. The Monte Carlo simulation approach was selected as it is able to quantify the uncertainty in the forecast. One sample of the Monte Carlo simulation represents the sum of the 20 production profiles that are assumed to be developed between 2010 and 2048. Production lead time and profile shape for each field have been randomly chosen to provide sufficient diversity to the simulation, while the time of the discovery and the chances of finding small, medium and large fields have been fixed. The simulation was run 50,000 times to obtain reasonable statistics and the 10th, 30th, 50th, 70th and 90th percentile production forecasts have been added to the production profile of existing fields (section 3) to obtain the total net gas production.

4.1 Monte Carlo simulation

4.1.1 Discovery time

Around 20 fields have been discovered and exploited over the last 40 years. A similar number of discoveries are assumed in the Monte Carlo simulation over the next 40 years. They have been evenly spaced at one every two years from 2010 to 2048. The Commission believes that this is a reasonable assumption and that randomly picking the discovery years would not add a lot of value as the size of the fields and the production lead time (see section 4.1.2 and 4.1.3) were randomly selected, already giving enough diversity to the simulation.

4.1.2 Production profiles of the fields

As mentioned earlier in this report, the pulse profile provides a good representation of the gas production profiles, and for this reason equation (1) has been selected as a typical production profile. Random input distributions have been used to give enough diversity to the simulation, and were selected within boundaries to obtain realistic production levels and field reserves. The A, t_1, t_2, and P parameters in equation (1) are randomly picked within boundaries for each of the field categories (see Table 2). The field categories have been based on the field sizes that have been discovered so far in New Zealand:

- a large field would have a roughly similar reserve and production profile to Maui;
- a medium field would have roughly a similar reserve and production profile to Kapuni or Pohokura; and
- a small field would be all the fields with a smaller reserve than the large and medium fields (e.g. Rimu, Tariki).

All the parameters are presented in the table below for the three field categories. The right hand column shows the field size boundaries.

Table 2: A, t_1, t_2 and P parameters boundaries and reserve range

Field category	A	t_1, t_2	P	Reserve, PJ
Large	2000-2500	8.0 - 9.0	4.0 - 5.0	2600-4000
Medium	300-600	4.0 - 6.0	1.0 - 2.0	400-1600
Small	20-150	2.0 - 4.0	1.0 - 10.0	5-280

4.1.3 Lead times between discovery and production

When a gas field is discovered there is a lead time before production starts. This lead time varies from one field to another but will mainly depend on the market for gas, the location (onshore/offshore), the size of the development, appraisal drilling, resource consenting, facilities fabrication and development drilling. In 2006, Power Projects Limited produced a report for the Commission containing the production lead times of New Zealand onshore and offshore field developments (Power Projects, 2006). Based on the lead times specified in this report, it was assumed in the current simulations that large and medium fields were likely to be offshore, therefore having a long lead time of 4 to 10 years and that smaller fields were likely to be onshore, therefore having a shorter lead time of 1 to 5 years[2].

4.1.4 Chances of finding large, medium and small fields

Historically, one large field (Maui), two medium fields (Kapuni and Pohokura) and seventeen small fields have been discovered in New Zealand, from which one could surmise to a 5%, 10% and 85% chance of finding a large, medium and small field, respectively. It is important to note that the Maui field had a very large reserve close to shore, and has contributed most of the overall production. New Zealand was clearly in an era of abundant gas supply. Obviously these percentages for future discoveries are highly uncertain, and one approach would be to use identical percentages in the simulation. Sensitivity analyses have been performed on the chance of finding large and medium field (see Appendix 1). The results show that the 5, 10 and 85 percentages lead to unrealistically high production. Another approach to get a reasonable gas production forecast is to assume that the highest gas production forecast (see later the 90th percentile forecast) would have a similar production level to the historical maximum gas production (approx. 250 PJ/year in 2001). Using this logic, the 3%, 12% and 85% chance of finding a large, medium and small field provide reasonable outputs and have been selected in the simulation.

4.2 Gas production forecasts

The production values of the 50,000 samples have been sorted within each year and the 10th, 30th, 50th, 70th and 90th percentiles have been selected to represent the very low, low, medium, high and very high gas production forecasts, respectively. The five production forecasts are shown in Figure 5, Figure 6, Figure 7, Figure 8 and Figure 9 going from the lowest to the highest gas production. From these figures it can be seen that:

- in the very low production forecast (10th percentile) the production drops quickly below 100 PJ/year and stabilises at a production of 30 PJ/year over the entire time horizon;
- in the low production forecast (30th percentile) the production drops below 50 PJ/year in 2025 and then goes back up to 60 PJ/year in 2050;

[2] x_0 in equation (1) is the discovery time plus the lead time.

- in the medium production forecast (50th percentile), the production gets to 70 PJ/year by 2023 which is roughly the quantity required for the residential,and commercial sectors, and to run existing Combined Cycle Gas Turbine (CCGT) plants. The orange area represents 2700 PJ which means that the 2008 reserve would be roughly doubled under this scenario;
- in the high production forecast (70th percentile), the production in 2025 is still reasonable at 100 PJ/year, which increases over time to reach an identical value to the 2007 production; and
- in the very high production forecast (90th percentile), the reserve is very large (approx. 7000 PJ) and the yearly peak production reaches similar values to the early 2000's (approx. 250 PJ/year), by 2045.

An interesting feature which came out of this simulation is that for all the forecasts there is a likely drop in production from 2013 to 2018. This drop is caused by the lack of new fields discovered in the last few years and the production lead time randomly picked in the simulation for the new discoveries (i.e. 1 and 5 years for onshore fields and from 4 to 10 years for offshore fields). Even if some large fields were found today, the production would only start between 2012 and 2018 (Figure 9) because of the time it takes to obtain the resource consent, to market the gas, and fabricate the facilities. The drop is less dramatic in the very high gas production forecast (Figure 9) than in the other ones as a greater number of small onshore fields could potentially produce gas within a couple of years.

Figure 5: Very low gas production forecast, 10th percentile

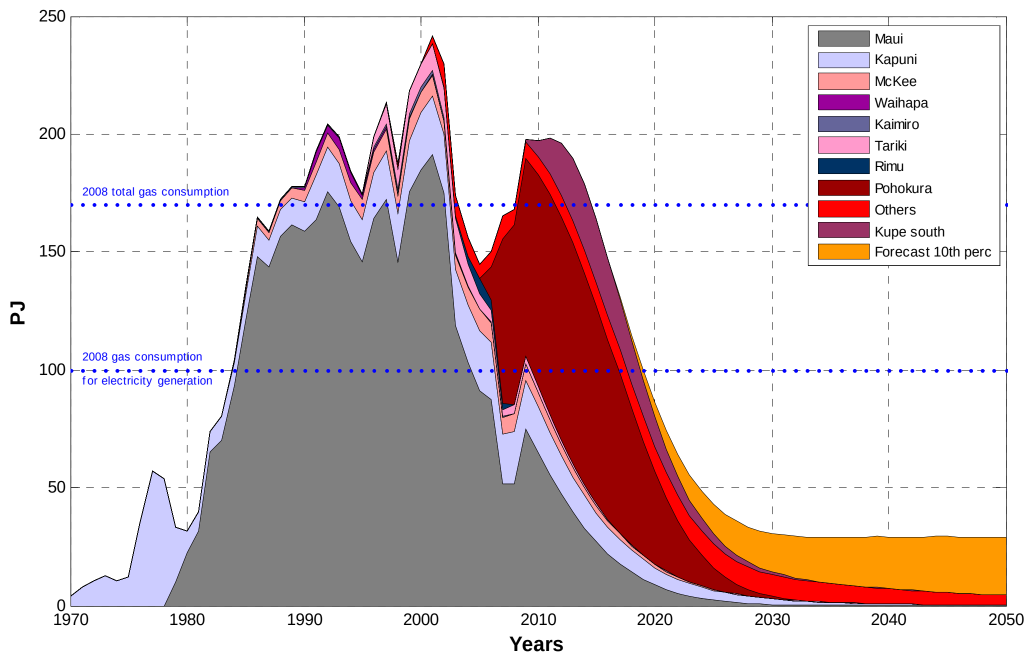


Figure 6: Low gas production forecast, 30th percentile

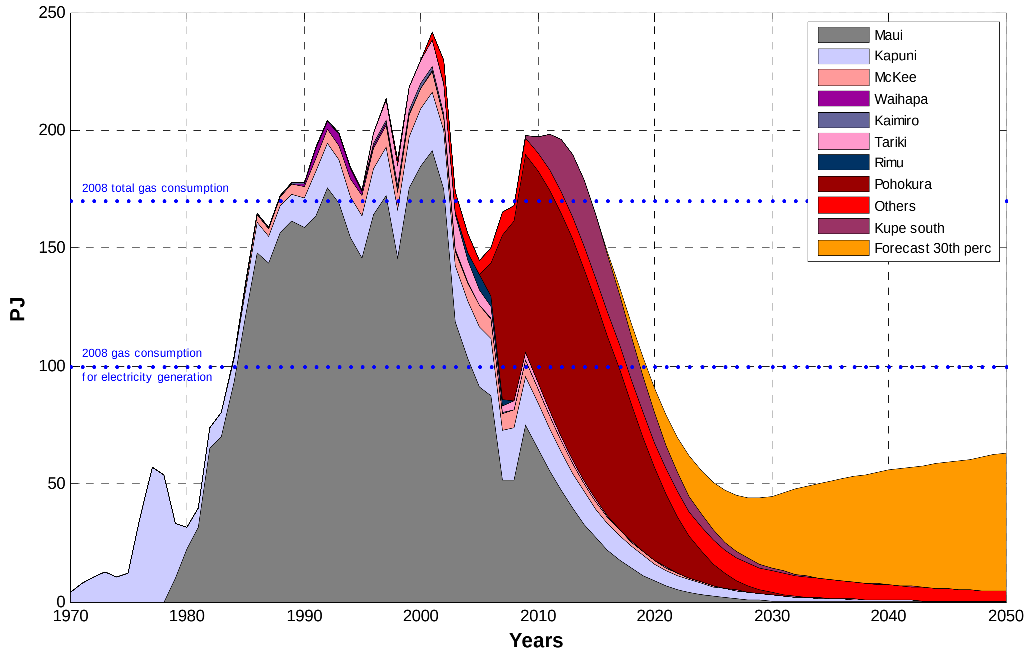


Figure 7: Medium gas production forecast, 50th percentile

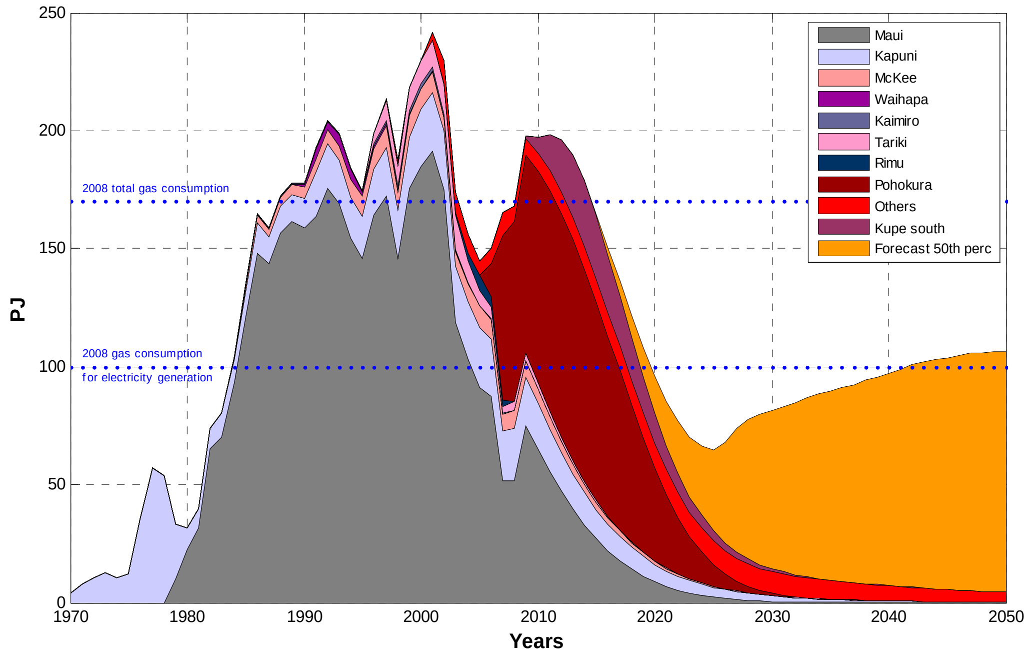


Figure 8: High gas production forecast, 70th percentile

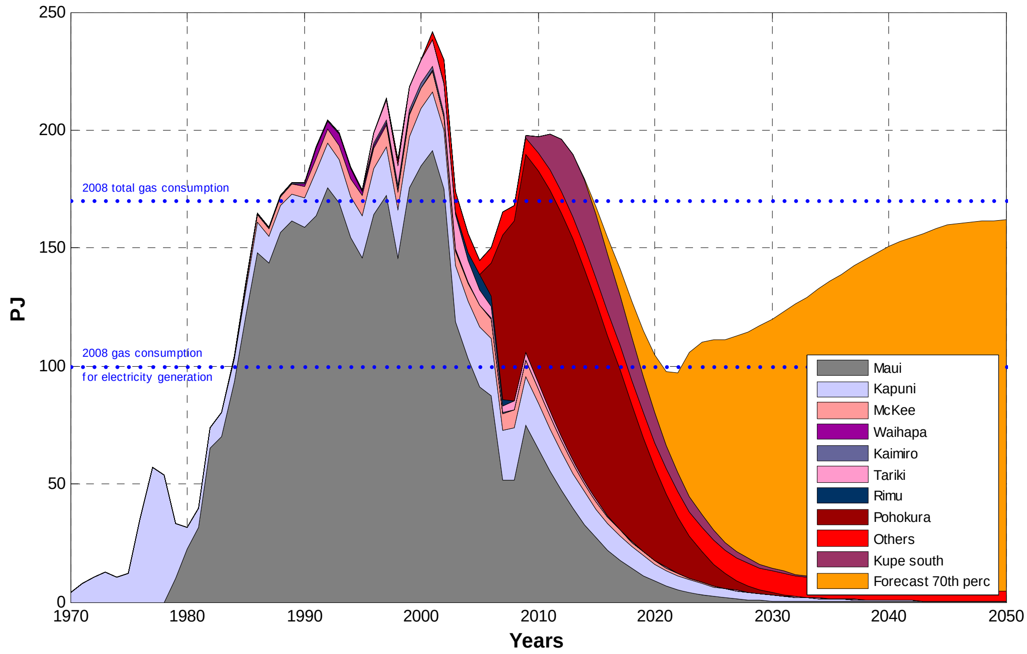
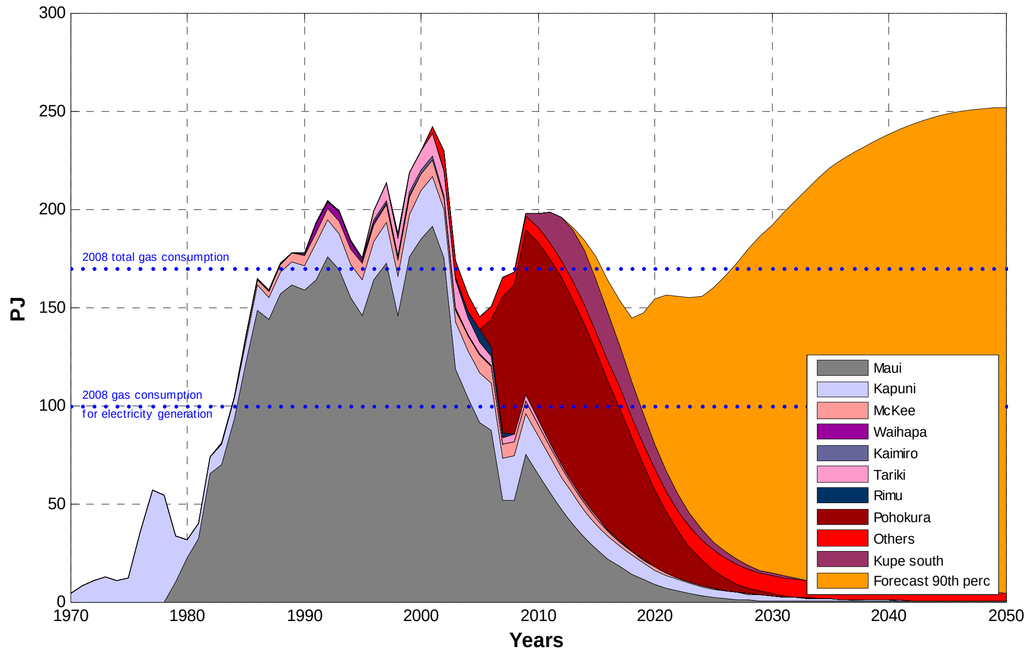


Figure 9: Very high gas production forecast, 90th percentile



4.3 Gas availability for electricity generation

Figure 5 to Figure 9 illustrate the total natural gas production which will be consumed by all sectors, and it is necessary to determine the energy available for electricity generation only. The main sectors currently consuming natural gas are the residential, commercial, industrial, petrochemicals and electricity generation sectors (MED, June 2008). In 2007 nearly 60% of the gas produced was consumed by the electricity generation sector but this market share was different in the past and is also likely to change in the future. The Commission has assumed that gas available for electricity generation would be the total production less the gas consumed by the residential, commercial and industrial sectors, as these sectors would most likely keep using gas if the price were to increase as they are the so-called higher value sectors. It is therefore assumed that the electricity generator sector has a higher ranking than the petrochemical sector in the merit order. In June 2008 the residential, commercial and industrial sectors represented 3.4%, 2.8% and 20.1% of total consumption (MED, June 2008) and it was assumed that these sectors would have a yearly growth of 1% for future demand. The consequential gas availability for electricity generation is given in Appendix 2.

5. Gas price forecasts

Historical quarterly price and net gas production data have been used to derive a relationship between the price and production, which was then applied to the five production forecasts. This relationship is applicable only for the shorter term as price would be affected by various other factors such as competition in the market, contractual arrangements, production capacity facilities, and re-determination of reserves. These parameters vary over time. For example, if, over the longer term, gas availability in New Zealand is very high, Liquefied Natural Gas (LNG) exports are possible. Conversely, LNG imports are possible if gas availability is low. In either case, the domestic gas price will be related to the international LNG price.

5.1 Production and price relationship

The historical (2000 to 2007) quarterly price and production have been obtained from MED's website and have been plotted in Figure 10.[3] A reasonable fit is obtained with an exponential equation given by:

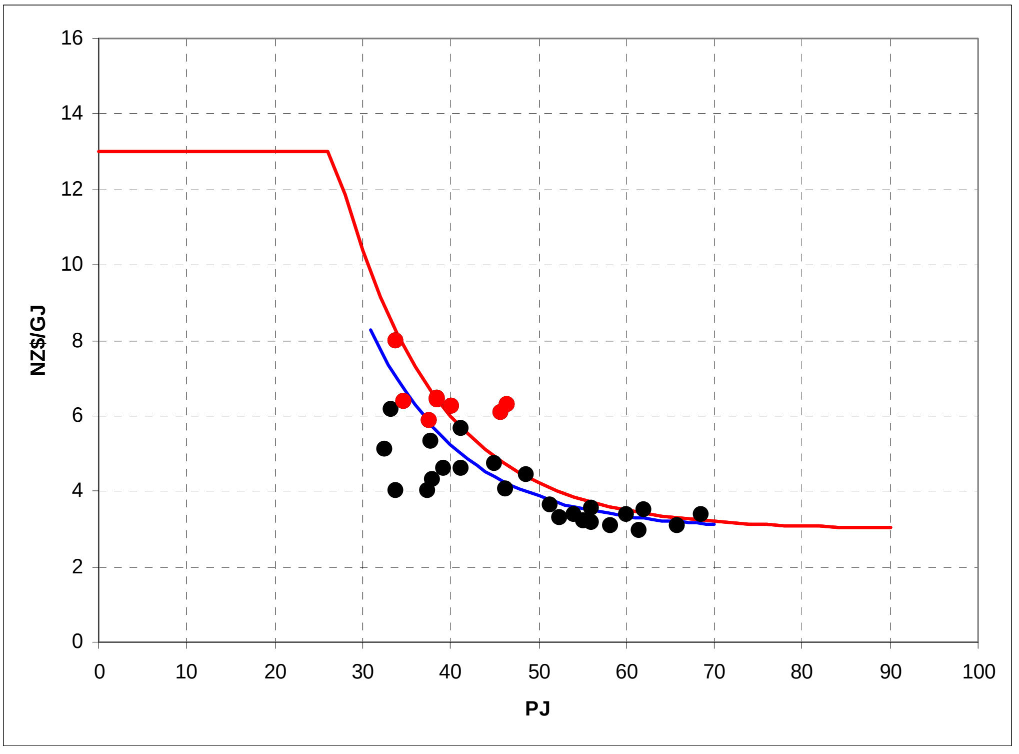
(2) $$y = a + be^{-(kx)}$$

[3] http://www.med.govt.nz/templates/MultipageDocumentTOC____21221.aspx
http://www.med.govt.nz/templates/MultipageDocumentTOC____21660.aspx

where *y* is the price in $NZ/GJ, *x* the quarterly production in PJ and with *a* = 3, *b* = 100 and *k* = 0.095 (blue line in Figure 10).

An exponential relationship seems reasonable as the price would be expected to rise sharply when the gas becomes scarce. Conversely, the price would be set to a floor value when the quantity available is large, as there will be always a minimum price to pay for extracting the resource.

Figure 10: Quarterly price versus production



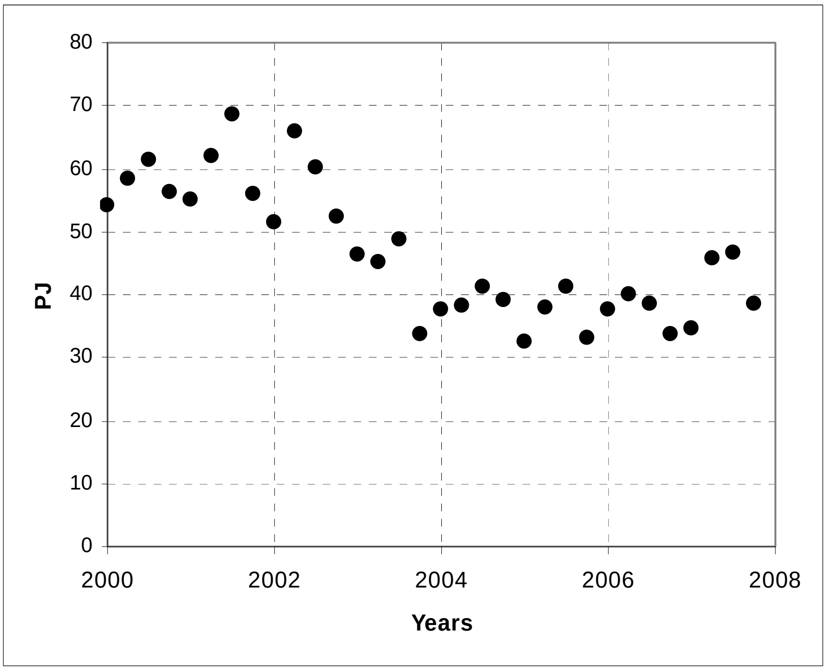
Notes: Black and red dots are the 2000 to 2007 data; the blue line is a good fit of the 2000-2007 dots. The red dots are the 2006-2007 data the red line in the range 32PJ-46PJ is a reasonable fit of these data.

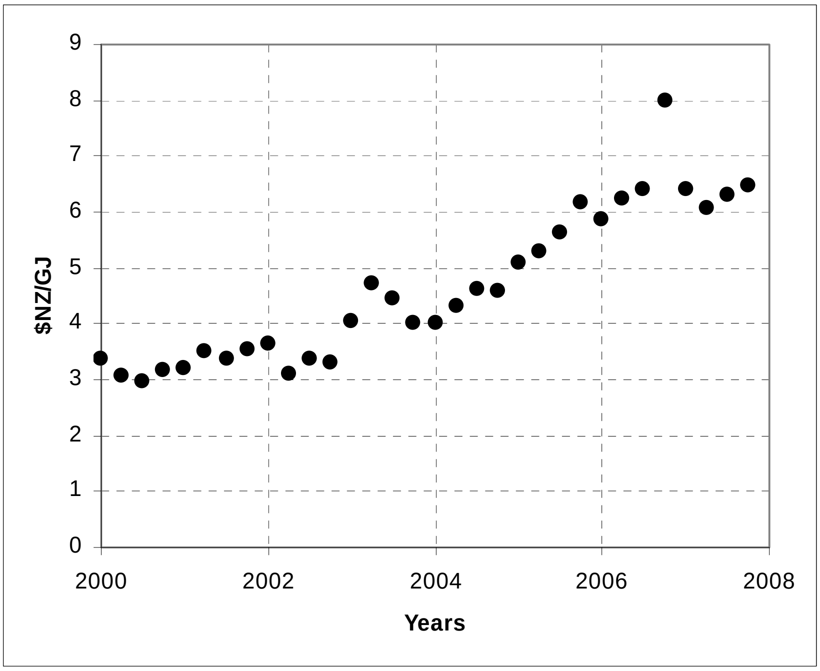
Two modifications to the blue line in Figure 10 have been applied:

- From Figure 10 it can be seen that similar quarterly production had different prices (see 38 PJ as an example) as the price is affected by several factors, as noted earlier. For example, between 2004 and 2007 it can be observed that the quarterly production was fairly constant at around 38 PJ but the price went up from $NZ4 to $NZ6.2 /GJ (see Figure 11) and this increase in price was mainly caused by the re-determination of the Maui reserve. Therefore, to better mirror the current gas market situation it seems reasonable to favour the latest data points (2006-2007, red dots in Figure 10) i.e. the *b* and *k* parameters in equation (2) have been changed to *b* = 110 and *k* = 0.09. The result is shown by the red line.
- The Commission has used a floor and ceiling price to mitigate price extremes. This technique is referred to as an S-curve approach, and is used to protect the sellers'

interest if the price drops below a certain threshold or to protect the buyers' interest if the price gets too high (Cedigaz, 2003; Eng, 2008). The floor price has been set to $NZ3/GJ which seems reasonable looking at the historical data (see Figure 10) while the ceiling price is difficult to determine from historical data. A rough calculation has been performed and is presented below to estimate the maximum fuel price that electricity generators would pay to power their plants.

Figure 11: Historical production and price





Assume that the average Long Run Marginal Cost (LRMC) of renewable generation is \$NZ95/MWh (Commission, 2008b). Thermal peakers would be necessary to back up some of the renewable generation (e.g. lack of wind, dry year) and this could increase the LRMC by around \$NZ10/MWh. In addition, because many renewable resources are located far from the load centres, additional costs (approx. \$NZ5/MWh) such as losses could be incurred in bringing the renewable energy to market. Taking all of this into consideration the LRMC of renewable generation could be estimated to be around \$NZ110/MWh and therefore the Short Run Marginal Cost (SRMC) of the gas power station would need to be of the same order to compete with renewable generation. The SRMC of baseload gas fired generation can be calculated by assuming that a typical CCGT plant would have an efficiency of 50% i.e. a heat rate of around 7,300 GJ/GWh, which leads to a gas price of around \$NZ15/GJ. This price would include a carbon charge which could be around \$NZ2-3/GJ (assuming CO_2 emissions of 60 kg/GJ from a gas fired plant and a carbon price of \$NZ40/tCO_2). Therefore, the maximum price that a generator running a CCGT gas plant would pay to be economic against other types of generators would need to be around \$NZ13/GJ. The ceiling price has been set to this value.

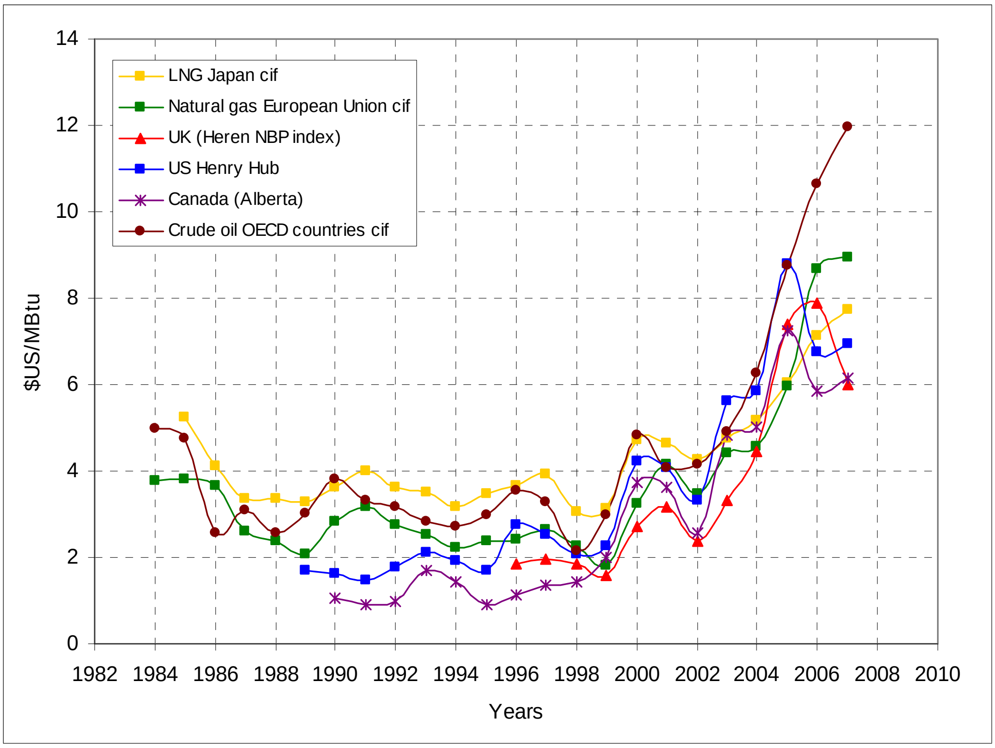
As mentioned previously it is important to note that the price-production relationship (red line in Figure 10) depends on various factors such as competition in the market, contracts, production capacity facilities and the uncertainty about future gas availability. Therefore, this relationship should only be assumed to hold in the short term. However, as discussed later in the document, some other effects (LNG import/export) will influence the domestic gas price and therefore the price-production relationship alone would not be expected to drive long term gas prices.

5.2 Longer term outlook: LNG trading price

It is believed that if New Zealand enters a period with either low or high gas production, there will be an incentive to either buy or sell gas overseas. It is well accepted that liquefying the gas, referred to as LNG, is the cheapest option of transporting gas over long distances. If New Zealand trades LNG it will inevitably affect the local price and it is therefore important to briefly review the worldwide LNG situation, and more particularly the Asian LNG market, because if New Zealand trades LNG, it would most likely be with this region.

The LNG market has developed rapidly since 1990 with an average annual production increase of 6.9 % between 1990 and 2007 (Cedigaz, 2003; Beyond Petroleum, 2008). The LNG price has risen drastically in the last few years (see Figure 12) as a result of increasing demand relative to supply and the strong linkage to oil prices in most markets. The industry has been trying to cut the cost of each of the LNG chain elements (exploration, liquefaction, shipping and regasification) especially in liquefaction where larger trains are being developed to take advantage of economies of scale (e.g. Qatar). However, higher development costs in most components of the oil and gas sectors, including LNG, over the last few years are expected to be, at least partly sustained into the future.

Figure 12: Natural gas and oil prices



Notes: cif means cost + insurance + freight (Beyond Petroleum, 2008), by convention 1 MBtu = 1.055 GJ

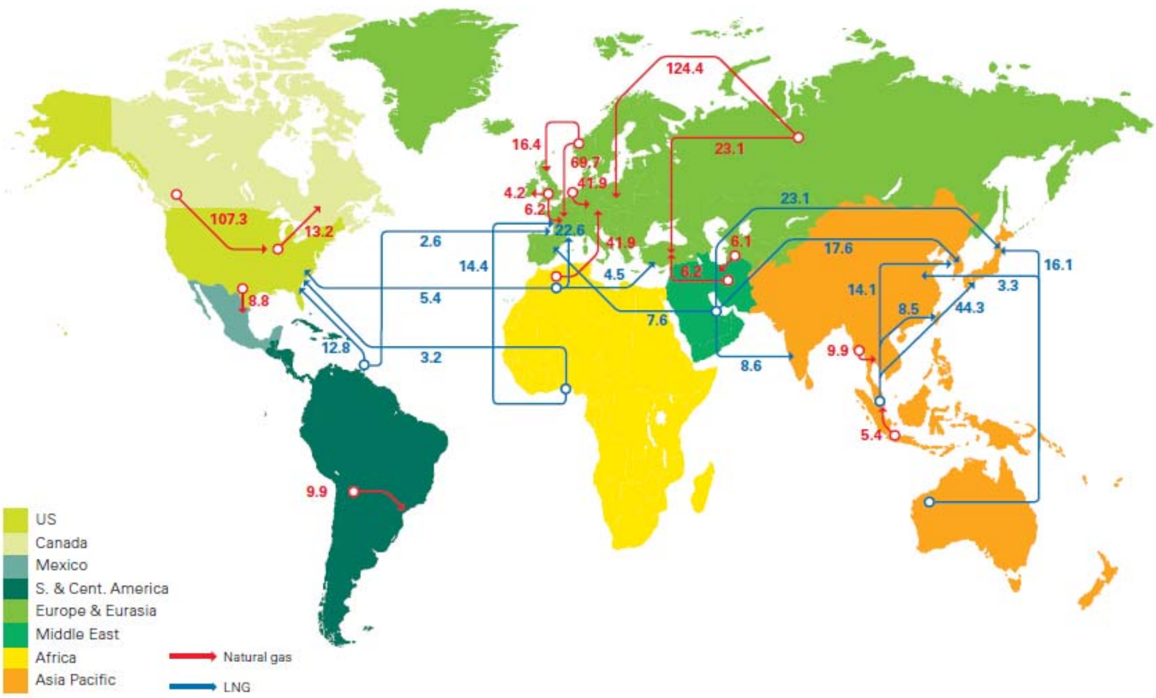
Recent LNG demand growth and a robust outlook have motivated continuing technological improvements in the LNG supply chain. Improvements to the process technology and efficiency of the plant reduce the smaller scale plant costs and therefore make the smaller reserves potential LNG resources. There are a number of small scale projects currently in planning stages and there is a clear effort worldwide to downscale LNG to monetise smaller reserves. For example, Origin has announced last year its intention to exploit a coal seam field in Queensland having a 2P reserve of 720 Billion cubic feet (Bcf)[4]. They are looking at exporting 60 PJ/year for 12 years from a potential LNG facility in Gladstone. The development of floating production platforms adds further flexibility for exploiting smaller and more remote gas resources.

The major regasification terminals in the Asian Pacific region are located in Japan, South Korea, China, Taiwan and India while the major suppliers of LNG to the Pacific market are Australia, Indonesia, Malaysia, and Qatar (see Figure 13) amongst others. Japan imported more than 3000 PJ in 2007 mainly from Australia, Indonesia, Qatar, and Malaysia.

4 1 Bcf can be considered to be roughly equal to 1 PJ

The LNG price will depend on a number of factors such as the pricing mechanism adopted between the parties (e.g. S-curve), the length of the contracts, freight arrangements, LNG spot price, etc. However, it is well accepted that the natural gas price and therefore the LNG price is generally linked to the price of crude oil (in Asia mainly the Middle Eastern grades). This is clearly illustrated by the correlation between the LNG price in Japan versus the oil price in Dubai from 1985 to 2007 in Figure 14 (Beyond Petroleum, 2008).

Figure 13: Major gas trade movements in 2008, Bcm[5]



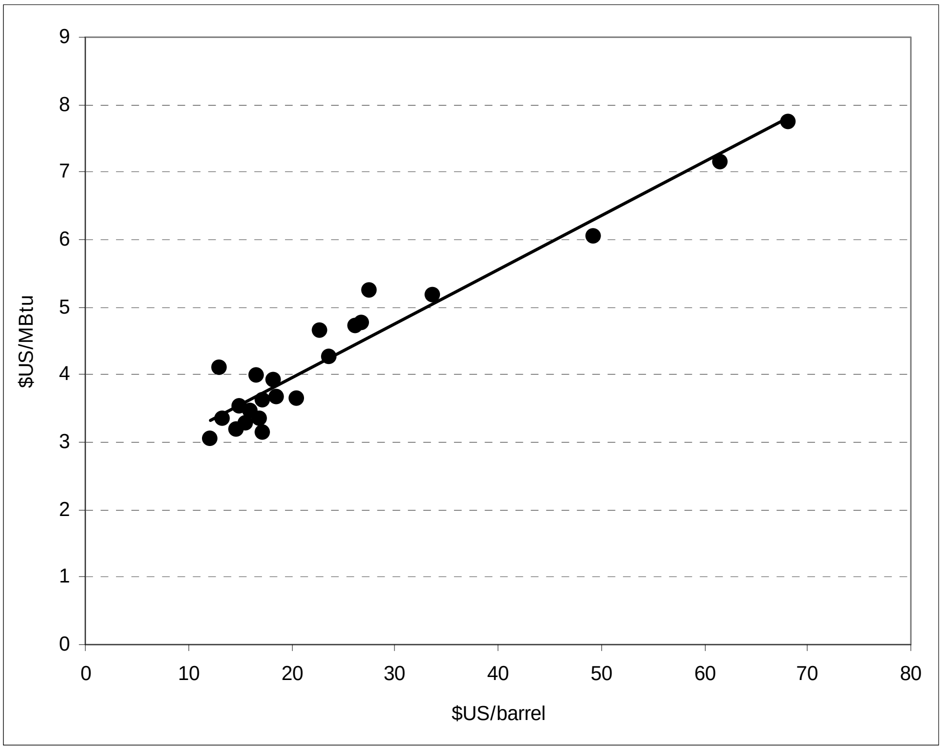
Source: Beyond Petroleum, 2008

LNG prices in 2008 were even higher than those shown in Figure 14 due to the linkage to high oil prices for contracted supplies and also an extremely buoyant spot market. For instance, last year, Japan has reached an agreement with Indonesia to import LNG at around $US18/MBtu using the oil parity price of $US110/barrel. More recently, prices have fallen in line with lower oil prices and falling overall demand. For new long-term contracts, there is generally a slightly higher correlation to oil prices than has historically been the case. Contracts are also often of shorter duration (10-15 years) and have more flexibility such as less rigid take-or-pay conditions and the removal of destination clauses.

[5] 1 Bcm can be considered to be roughly equal to 35 Bcf (~35 PJ)

If New Zealand joins the LNG market it is likely that the gas will be traded in the Asian market i.e. if New Zealand buys LNG the gas would probably be imported from regional suppliers such as Australia, Papua New Guinea or Malaysia, and if it exports LNG the potential buyers are likely to be countries such as China, Japan or South Korea. Like other countries in the Asian region, the LNG price to/from New Zealand would be close to the oil parity (1 barrel of oil is roughly equivalent to 5.8 MBtu of natural gas). Using oil parity and assuming $US/$NZ exchange rate of 0.65 and with the oil price at $US100/barrel, the price of trading LNG for New Zealand would be around $NZ25/GJ. Similar calculations have been performed by Gary Eng and show that the price could be as high as $NZ23/GJ at $US100/barrel (Eng, 2008). In addition, it is important to note that this price could be even higher if New Zealand imports LNG, as it would not be expected to import large quantities of gas in comparison to other Asian countries, and therefore might not benefit from economies of scale.

Figure 14: LNG price in Japan versus the oil price in Dubai



Source: Beyond Petroleum, 2008

If large quantities of gas are discovered in New Zealand either offshore (e.g. Deepwater Taranaki), in the South Island (e.g. Great South basin) or even not far from existing infrastructure in the North Island (e.g. East Coast, Northland and Taranaki), the field owners could sell it internationally at a potentially higher price than the local market would be prepared to pay due to the previously mentioned alternative of renewable generation in New Zealand (section 5.1) and the likely limited size of the New Zealand gas market. The domestic gas price could therefore be set to the international LNG price minus the cost of liquefaction, shipping and regasification.

Current estimates are that LNG can be economically produced and delivered for about $US2.6 to 4.80 /MBtu (CEE, 2007).This is an approximate cost range as it will vary according to the producing country and shipping distance. The shipping cost from New Zealand to Asian countries might be on the high side in comparison with other suppliers such as Australia and Indonesia. For this reason, the upper bound of the price range has been used i.e. $US4.55/GJ. This latter value concurs with a Centre for Advanced Engineering report which mentioned that the LNG supply chain would cost around $US4.78/GJ (CAE, 2004). By using the cost breakdown of the LNG supply chain (IEA, 2004) and an $US/$NZ exchange rate of 0.65 it was estimated that the cost of the liquefaction, shipping and regasification could be at around $NZ6/GJ. It was shown previously that LNG could be sold to Asian countries at around $NZ25/GJ minus the cost of liquefaction, shipping and regasification, giving a local gas price of $NZ19/GJ.

It is clear that the domestic gas price would be very sensitive to the oil price (via the LNG price) and the exchange rate. The table below presents sensitivity analyses on these two parameters in the event that New Zealand exports gas. LECG has done some similar work for the Gasbridge joint venture assuming that New Zealand would import LNG and also shown some important variations (LECG, 2006). Previously in this report it was estimated that the gas fired generator could pay as much as $NZ13/GJ to still be economic against other types of generation. Table 3 shows that if New Zealand was exporting LNG it would be economic for the gas fired generator to buy gas only if the international oil price was below $US70-80/barrel and with an exchange rate of 0.65. On the other hand, if the exchange rate becomes very favourable and the oil price decreases to $US50/barrel, the local gas price could be as low as $NZ5.8/GJ.

Table 3: New Zealand gas price in $NZ/GJ when New Zealand exports LNG

	Oil price, $US/barrel		
Exchange rate, $US/$NZ	**50**	**100**	**150**
0.55	7.9	22.8	37.6
0.65	6.7	19.3	31.8
0.75	5.8	16.7	27.6

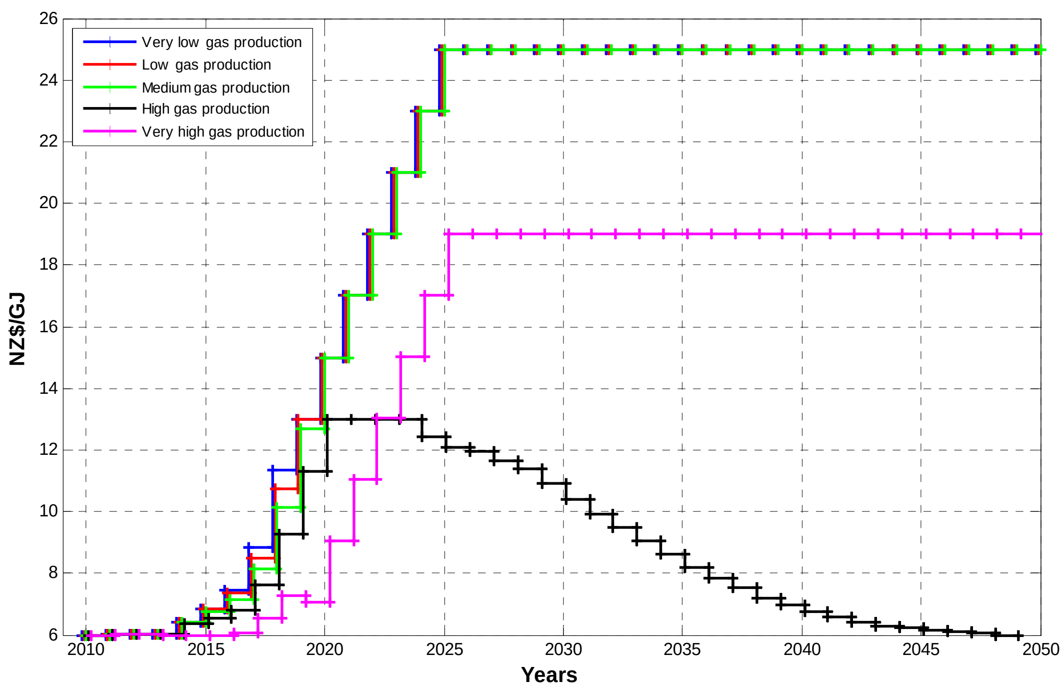
5.3 Gas price forecasts

The production-price relationship has been used to obtain the gas price forecasts and have also been adjusted according to the following:

- As mentioned in Section 3 Methanex restarted production in 2008 and could run for 4-5 years. It is assumed here that Methanex would use 40 PJ/year for 5 years and has secured adequate quantities at agreed prices with the field owners. This means that the production and therefore the price could stay roughly constant for other participants over the next 4-5 years;

- Various reports have mentioned that New Zealand could import LNG to meet an annual gap of 60-80 PJ (CAE, 2004; LECG, 2006). The Commission's forecast assumes that if the domestic gas availability for electricity generation falls below 60 PJ/year, then the price should be set to the international LNG price, i.e. $NZ25/GJ as New Zealand would then import LNG but not earlier than 2020. A gradual transition to the international LNG price over a period of 5 years has been assumed. The quantity available at this price would be unlimited. This situation occurs for the 10^{th,} 30th and 50th percentile forecast in 2020; and
- Due to high gas demand worldwide and new LNG production technology there is a clear incentive to build smaller scale LNG processing plant in order to exploit smaller reserves. It is assumed that LNG would be exported as production exceeds 100 PJ/year and future production looks optimistic. Also it is assumed that New Zealand would have LNG liquefaction facilities not earlier than 2020. As explained earlier in this report, New Zealand could pay as much as $NZ19/GJ and this price is highly sensitive to oil prices and exchange rates. This situation occurs for the 90th percentile forecast in 2020 and a gradual transition to the international LNG price over a period of 5 years has been assumed.

Figure 15: Gas price forecasts



Appendix 3 presents the gas price forecast data.

Figure 15 shows that, over the short term, gas prices are expected to rise. This trend is most likely due to insufficient gas exploration and success over the last ten years and the lead time between discovery and production of any new fields. Over the longer term, if New Zealand experiences a low or high gas production scenario, the domestic gas price would be expected to be strongly influenced by the international LNG market and therefore likely become more volatile. The international LNG price that New Zealand would face would vary primarily according to international oil price and $US/$NZ exchange rate. For example in 2008 global LNG prices were high and volatile in all regional markets. Price increases were mainly explained by a steep rise in oil price, high natural gas demand and also delayed investments on the supply side. Gas prices in all regional markets are expected to continue to climb in the short term because of higher demand for oil, increases in production costs and uncertainties in relation to gas infrastructure investment.

It can also be seen from Figure 15 that the lowest domestic gas price could actually be expected for a high gas production scenario as, under this scenario, New Zealand would stay decoupled from international LNG trading. This narrow band of production represents a quantity large enough to meet demand, and consequently not require LNG importation, but is still sufficiently small so as not to make LNG exports a viable prospect. The location of the discovery relative to the current infrastructure would also play a role whether or not to invest in LNG plant. The LNG market is growing rapidly and has become an economic and competitive means of energy distribution, which is clearly proved by the worldwide effort to downscale LNG plant. This could have the effect of reducing even further the size of the production band that is decoupled from LNG trading.

In addition, petrochemical demand in New Zealand has the potential to strongly influence the supply/demand balance and therefore the domestic gas price. As mentioned earlier Methanex restarted production and is expected to use a fairly large amount of gas over the next years (approx. 30-40 PJ/pa). Methanex are acting as a swinging participant in using gas over the next 4-5 years, while gas supply is plentiful. However in the future, additional gas discoveries could become highly valued if demand increases or the electricity sector experiences a dry hydrological period. Furthermore, if the energy stack from renewable generation increases, more fast start peakers (e.g. OCGT) would be required. [6]

6. Impact on the power system

6.1 Introduction

The gas production and price forecasts presented in this document are significantly different from the assumptions used in the 2008 SOO scenarios where gas prices varied from $NZ5/GJ to $NZ13/GJ in the 75 PJ/year scenarios, up to $NZ8/GJ in the high gas discovery

[6] Contact Energy is already addressing this with the recent acquisition of the Ahuroa gas field with the intention of developing it as a storage facility.

scenario. However, as mentioned earlier, the present analysis suggests that gas prices could be much higher. Such high prices would significantly impact the power system.

To investigate such impacts, the forecasts presented in this document have been input into GEM [7] . Because many of the key drivers differed between the 2008 SOO scenarios, there is little value in studying the impact of the forecasts on all of the existing SOO scenarios. For this reason, a new GEM baseline scenario was established. The GEM results from the new baseline were then compared with the results when gas availability and price are varied in line with the forecasts described earlier in section 4 and section 5. The new GEM baseline uses a selection of key drivers chosen from the five market development scenarios described in the 2008 SOO. The key features of the new baseline scenario are presented in the table below.

Table 4: Features of the baseline scenario

Features
• Renewables are developed in both islands • Thermal peakers supplement intermittent renewable generation • Gas price reaches \$11/GJ by 2024 • Gas availability is 75 PJ/year • Carbon price is set at \$40/tCO_2e from 2010 • HVDC Half-pole 1 is on standby until the replacement in 2012 • No major change in demand side response, and electric vehicle uptake is insignificant • Tiwai smelter remains in operation • About 85% of electricity generation is from renewable sources by 2025.

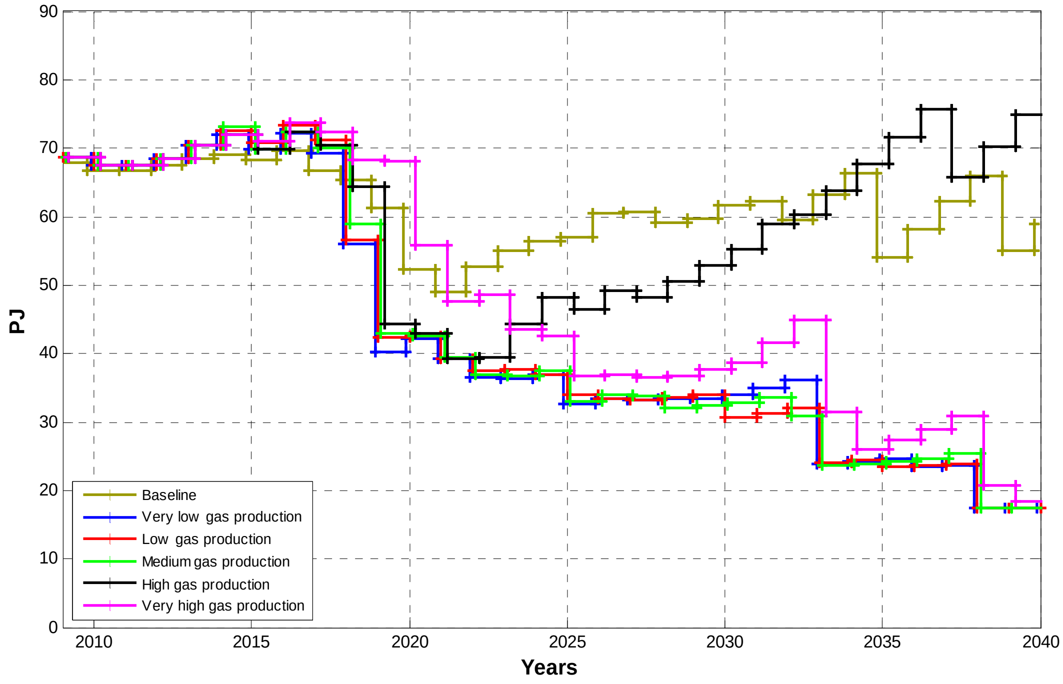
6.2 GEM analysis

Appendix 4 presents plots depicting the installed capacity of gas, diesel, hydro, wind and coal Carbon Capture and Storage (CCS) generation plant as derived by GEM using the baseline scenario and the five production and price forecasts. The results indicate that:

[7] http://www.electricitycommission.govt.nz/opdev/modelling/gem

- The installed capacity of gas fired stations stays relatively constant up to 2023 for all the gas production forecasts with consumption of gas declining (see Figure 16) as the price starts to rise around 2017.
- The gas consumption in the baseline scenario also drops as the gas price rises from NZ$6/GJ to NZ$10/GJ by 2020. After 2020, the variations in gas price (see Figure 15) become more important and this is reflected by the gas consumption falling even further for all the forecasts except the baseline and the high gas production forecast.
- By the mid-2030s, the cumulative installed capacity of gas fired plant begins to decrease as plants are decommissioned and no new gas fired stations are being built due to the high gas prices ($NZ19-25/GJ). This results in an installed capacity of 1000 MW by 2040. In the high gas production forecast, the installed capacity of gas fired stations increases up to 2500 MW over the entire time horizon.
- In the cases where gas prices are high, the system requires additional installed capacity using other technologies to meet demand. According to this analysis, between 2020 and 2030 more wind generation is required to make up for the lack of generation from gas fired plants. Diesel peakers are also constructed to balance intermittent generation from wind generation and supply reliable capacity at peak demand.
- Post 2030, coal CCS is being installed to firm up generation. As at this stage coal CCS is not a confirmed viable technology; the earliest commissioning years of the coal CCS plants has been set to 2030 in the baseline scenario and for this reason no coal CCS plant is being built prior to 2030. Analysis using GEM indicates that if coal CCS technology does not develop further and becomes cheaper, then additional wind, diesel peaker and hydro generation would be needed post 2030 to meet demand. In these runs the maximum wind penetration of 20 % is reached and hydro generation is then the next most economic generation to be built. As at the time of writing this paper, the Commission’s modelling team is carrying out further investigation into the ability of the power system to absorb more wind generation.

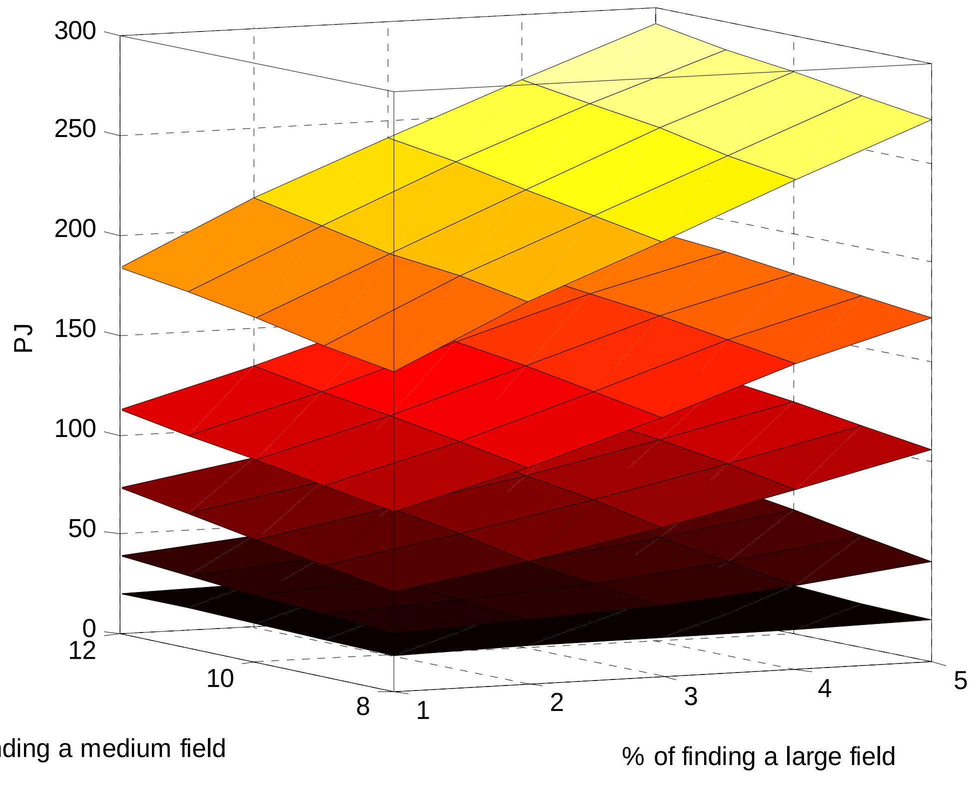
Figure 16: Gas consumption for electricity generation



Appendix 1 Field size discoveries

The Monte Carlo simulation was run with various chances of finding large and medium fields from 1% to 5 % and 8% to 12%, respectively. The average energy level, PJ, from 2040 to 2050 has been derived from these runs. The energy levels of the 10th, 30th, 50th, 70th and 90th percentiles (darker to lighter colours) are shown in Figure 17. It can be observed that the chances of finding large, medium and small fields are sensitive parameters. For instance, in the 90th percentile if the chances of finding a large and medium field respectively are selected to be 5% and 12% the production in 2040-2050 could be as high as approximately 300 PJ. Conversely if 1% and 8 % are selected, only 150 PJ of production predicted.

Figure 17: Average gas production from 2040 to 2050 versus the chances of finding a large and medium size field



Notes: The 10th, 30th, 50tth, 70th and 90th percentile are represented by each layers going from the darker to the lighter colours

Appendix 2 Gas available for electricity generation, PJ

Years	10th	30th	50th	70th	90th	Years	10th	30th	50th	70th	90th
2009	116	116	116	116	116	**2031**	Unlim	Unlim	Unlim	67	142
2010	115	115	115	115	115	**2032**	Unlim	Unlim	Unlim	69	148
2011	115	115	115	115	115	**2033**	Unlim	Unlim	Unlim	72	153
2012	114	114	114	114	114	**2034**	Unlim	Unlim	Unlim	74	158
2013	113	113	113	113	114	**2035**	Unlim	Unlim	Unlim	77	163
2014	108	108	108	108	113	**2036**	Unlim	Unlim	Unlim	80	167
2015	102	102	103	105	113	**2037**	Unlim	Unlim	Unlim	83	171
2016	95	96	98	102	112	**2038**	Unlim	Unlim	Unlim	86	174
2017	82	85	88	93	105	**2039**	Unlim	Unlim	Unlim	88	177
2018	66	69	73	79	95	**2040**	Unlim	Unlim	Unlim	90	179
2019	50	54	59	66	97	**2041**	Unlim	Unlim	Unlim	89	177
2020	Unlim	Unlim	Unlim	55	104	**2042**	Unlim	Unlim	Unlim	91	180
2021	Unlim	Unlim	Unlim	47	105	**2043**	Unlim	Unlim	Unlim	92	180
2022	Unlim	Unlim	Unlim	45	105	**2044**	Unlim	Unlim	Unlim	93	181
2023	Unlim	Unlim	Unlim	54	104	**2045**	Unlim	Unlim	Unlim	94	182
2024	Unlim	Unlim	Unlim	57	105	**2046**	Unlim	Unlim	Unlim	94	183
2025	Unlim	Unlim	Unlim	58	108	**2047**	Unlim	Unlim	Unlim	94	184
2026	Unlim	Unlim	Unlim	59	112	**2048**	Unlim	Unlim	Unlim	94	184
2027	Unlim	Unlim	Unlim	59	118	**2049**	Unlim	Unlim	Unlim	94	184
2028	Unlim	Unlim	Unlim	60	124	**2050**	Unlim	Unlim	Unlim	94	184
2029	Unlim	Unlim	Unlim	62	130						
2030	Unlim	Unlim	Unlim	64	136						

Unlim= Unlimited quantities (LNG import)

Appendix 3 Gas price data, $NZ/GJ

Years	10th	30th	50th	70th	90th	Years	10th	30th	50th	70th	90th
2009	6.0	6.0	6.0	6.0	6.0	**2031**	25	25	25	10.0	19
2010	6.0	6.0	6.0	6.0	6.0	**2032**	25	25	25	9.5	19
2011	6.0	6.0	6.0	6.0	6.0	**2033**	25	25	25	9.1	19
2012	6.0	6.0	6.0	6.0	6.0	**2034**	25	25	25	8.7	19
2013	6.0	6.0	6.0	6.0	6.0	**2035**	25	25	25	8.3	19
2014	6.4	6.4	6.4	6.4	6.0	**2036**	25	25	25	7.9	19
2015	6.8	6.8	6.8	6.6	6.0	**2037**	25	25	25	7.5	19
2016	7.5	7.3	7.1	6.8	6.1	**2038**	25	25	25	7.2	19
2017	8.8	8.5	8.2	7.6	6.5	**2039**	25	25	25	6.9	19
2018	11.3	10.7	10.1	9.3	7.3	**2040**	25	25	25	6.7	19
2019	13	13	12.7	11.3	7	**2041**	25	25	25	6.7	19
2020	15	15	15	13	9	**2042**	25	25	25	6.6	19
2021	17	17	17	13	11	**2043**	25	25	25	6.4	19
2022	19	19	19	13	13	**2044**	25	25	25	6.3	19
2023	21	21	21	13	15	**2045**	25	25	25	6.2	19
2024	23	23	23	12.4	17	**2046**	25	25	25	6.1	19
2025	25	25	25	12.1	19	**2047**	25	25	25	6.1	19
2026	25	25	25	11.9	19	**2048**	25	25	25	6.1	19
2027	25	25	25	11.8	19	**2049**	25	25	25	6.0	19
2028	25	25	25	11.5	19	**2050**	25	25	25	5.9	19
2029	25	25	25	11.0	19						
2030	25	25	25	10.5	19						

Appendix 4 Technology lineplots – total installed capacity by production forecast and year

Figure 18: Installed capacity of gas

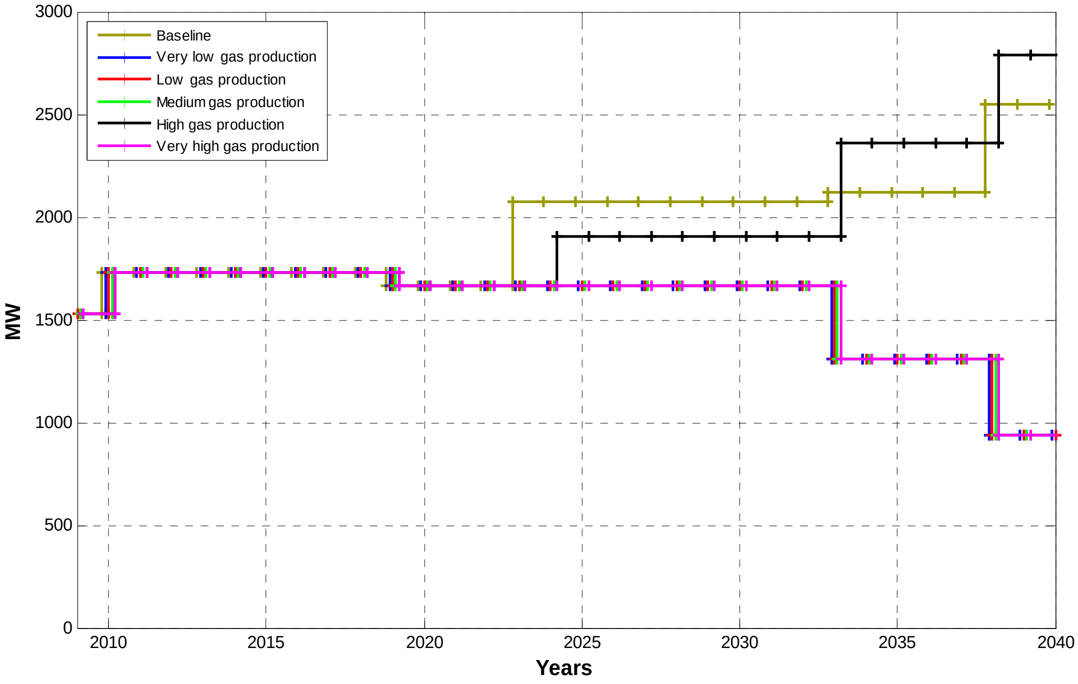


Figure 19: Installed capacity of diesel

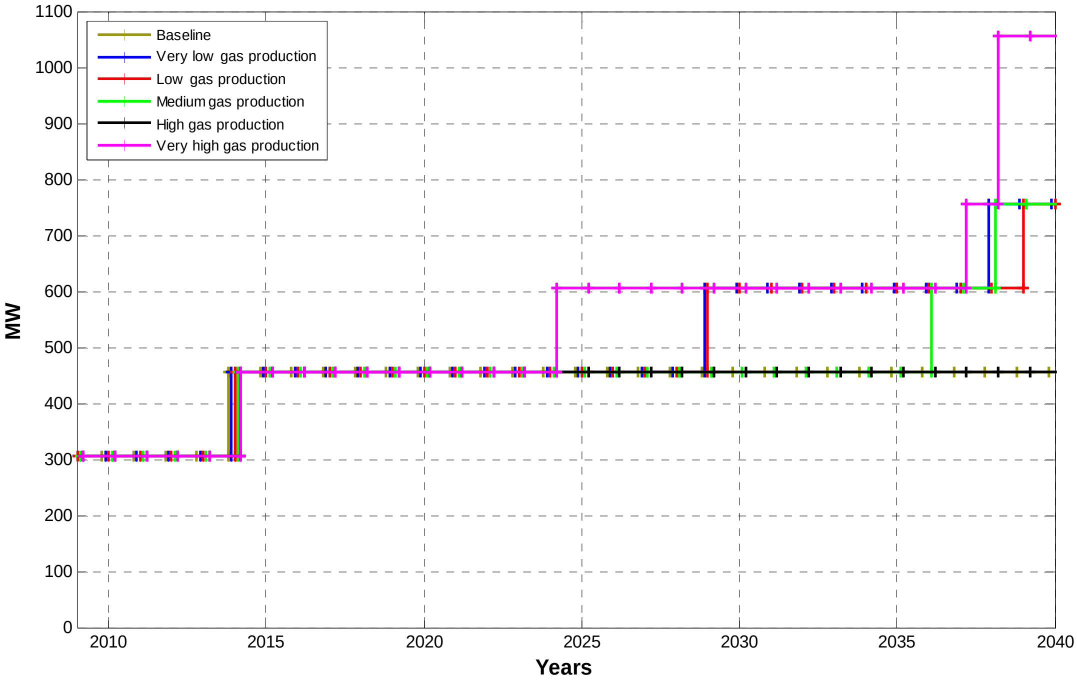


Figure 20: Installed capacity of hydro

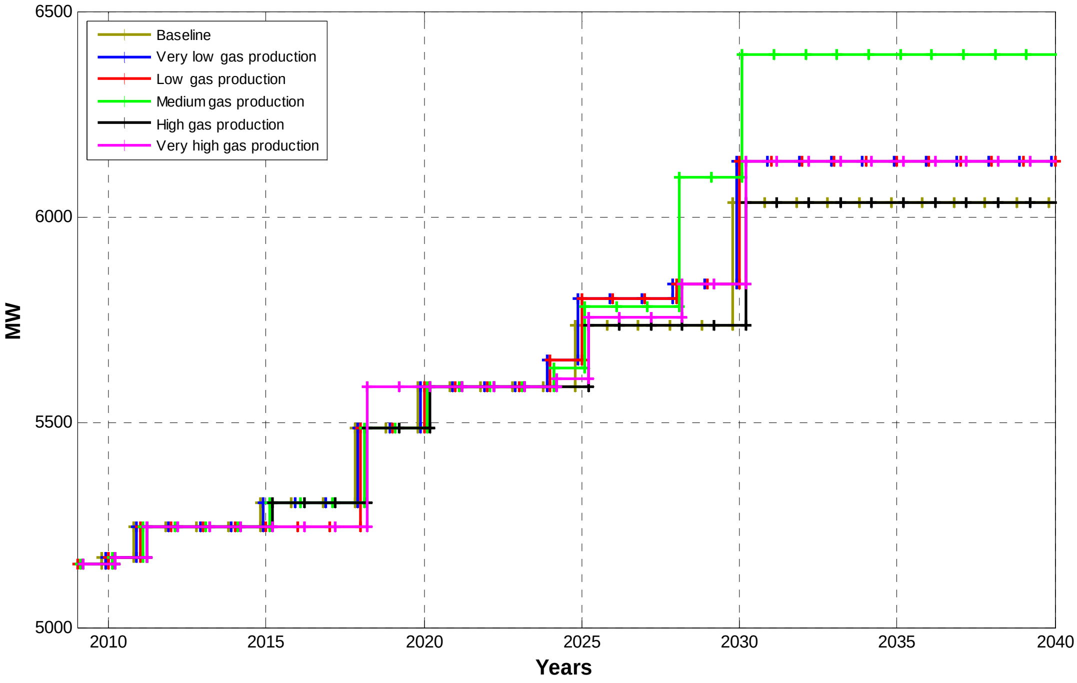


Figure 21: Installed capacity of wind

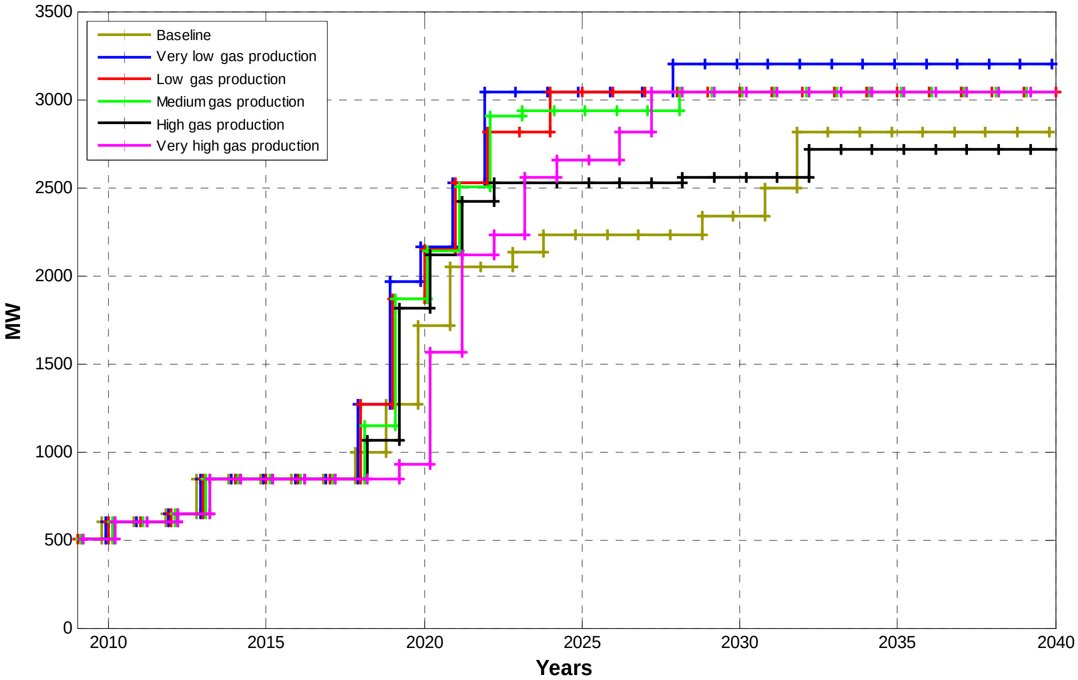
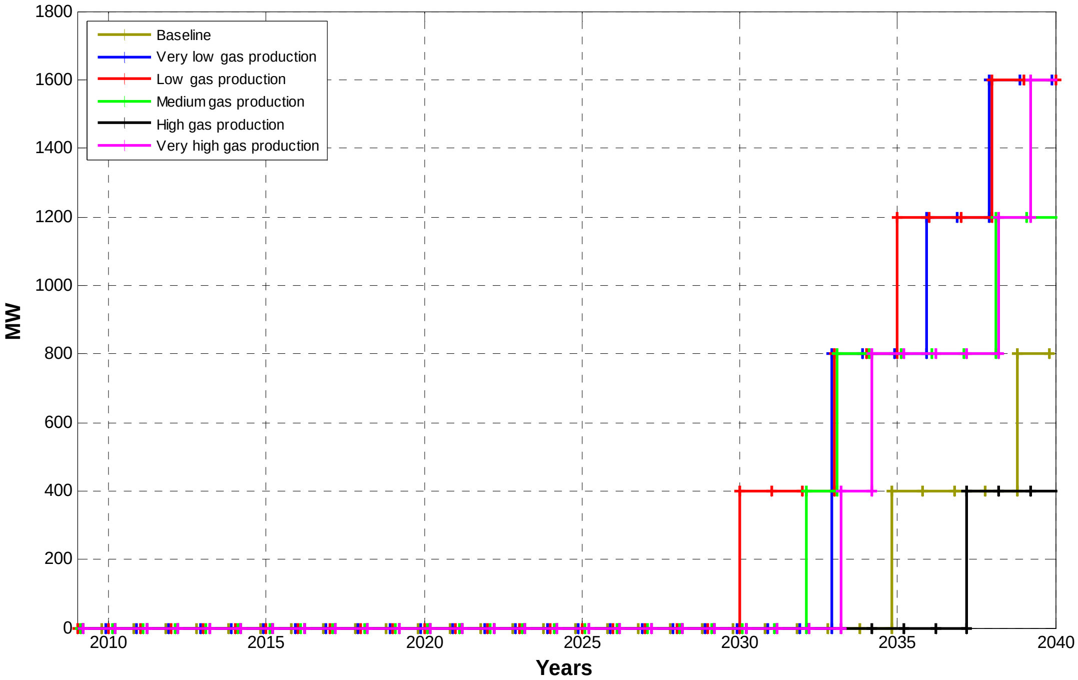


Figure 22: Installed capacity of coal CCS



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