www.concept.co.nz

Long term gas supply and demand scenarios – 2019 update

16 September 2019

About Concept

Concept Consulting Group Ltd (Concept) specialises in providing analysis and advice on energy-related issues. Since its formation in 1999, the firm's personnel have advised clients in New Zealand, Australia, the wider Asia-Pacific region and Europe. Clients have included energy users, regulators, energy suppliers, governments, and international agencies.

Concept has undertaken a wide range of assignments, providing advice on market design and development issues, forecasting services, technical evaluations, regulatory analysis, and expert evidence.

Further information about Concept can be found at www.concept.co.nz.

Disclaimer

This report has been prepared by Concept based entirely on our analysis of public information sources.

Except as expressly provided for in our engagement terms, Concept and its staff shall not, and do not, accept any liability for errors or omissions in this report or for any consequences of reliance on its content, conclusions or any material, correspondence of any form or discussions, arising out of or associated with its preparation.

The analysis and opinions set out in this report reflect Concept's best professional judgement at the time of writing. Concept shall not be liable for, and expressly excludes in advance any liability to update the analysis or information contained in this report after the date of the report, whether or not it has an effect on the findings and conclusions contained in the report.

This report remains subject to any other qualifications or limitations set out in the engagement terms.

No part of this report may be published without prior written approval of Concept.

Contents

Acknowledgement

The authors wish to thank the individuals and organisations that participated in interviews with staff from Concept and the Gas Industry Co as part of this project. The information provided by these organisations was extremely useful as a supplement to published data sources.

Executive summary

Introduction and purpose

This 2019 Gas Supply and Demand study is the fourth in a series of such reports commissioned by Gas Industry Company. These studies:

- analyse the long-term drivers of outcomes in the New Zealand gas industry – both the upstream supply-side of the industry, and the various demand segments
- develop long-term projections of possible futures for the sector, based on modelling of the key sector drivers identified in the study.

For this 2019 study, new modelling capability has been developed to explore two key issues facing New Zealand's gas sector:

- The end-of-life of some of New Zealand's largest gas-producing fields occurring within the next 10 to 15 years, and the economic factors and policy settings driving possible development of new fields.
- The implications of various climate-change-related policies including:
  - Altered oil & gas exploration policy settings
  - Higher potential carbon prices
  - The policy goals of achieving
    - 100% renewable electricity generation by 2035 in a normal hydrological year; and
    - net-zero carbon emissions by 2050.

Modelling methodology

A model was used to project possible futures for supply and demand. At the core of this model is the fundamental logic that investment in the development and production of gas resources in a given year is only undertaken if the cost of development is less than the willingness-to-pay by the demand-side for that gas.

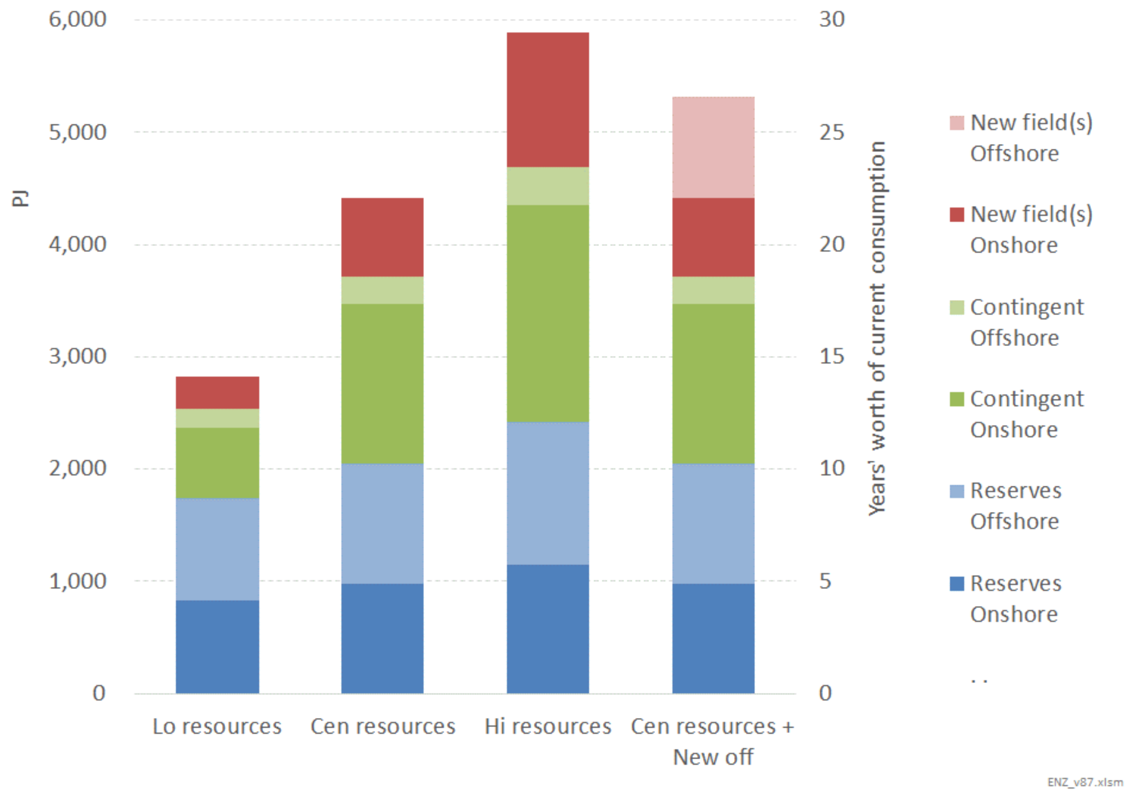
This demand-side willingness-to-pay is set by the cost of alternatives – being the cost of overseas production for the petrochemicals sector, and the cost of fuel switching for all other demand segments. For all demand segments, this willingness-to-pay is factored by the carbon price.

As New Zealand's gas reserves and resources become depleted, another alternative starts to drive modelled pricing outcomes – being the future cost of importing LNG if New Zealand continues consuming gas to the point where it will eventually have insufficient gas supply to meet demand. As the time when New Zealand would have to import LNG gets closer, the time-discounted effect on gas prices in a given year starts to rise. This results in a 'price rationing' effect – that is, some demand will switch to their non-NZ-gas alternative if the price of gas rises above their willingness-to-pay. This price rationing preserves a greater amount of remaining NZ gas resources for higher-value gas users, and postpones the time when LNG imports would be required.

Several scenarios were run which varied two key parameters.

The first scenario sensitivity is the amount of gas reserves and resources that could be developed to meet demand as shown in Figure 1 below. Four different scenarios were run (as illustrated along the x-axis) as to the amount of additional gas reserves and resources available for development. These were based on published MBIE data regarding additional reserves and resources from existing fields, plus GNS & MBIE analysis on potential gas from 'New', yet-to-be-discovered fields.[1]

Figure 1: Scenarios for scale of additional reserves and resources available for development as at 1 Jan 2019



[1] The Central scenario was based on published 2P reserves and 2C resources values for each existing field, with the estimate of new (as-yet-undiscovered) onshore fields being based on published MBIE modelling using GNS data. The published contingent resources values were factored by 75% to reflect other factors which will affect whether a resource classed as contingent will be developed.
The Low and High scenarios factored the Central scenario, based on published data on the extent of physical uncertainty regarding the size of reserves, with scaling factors applied to reflect the greater uncertainty over the size of contingent resources and new fields. An additional factor was applied in the Low scenario to the Kapuni contingent resources.
The Cen resources + New off scenario is the same as the Central scenario, but with an additional offshore field being discovered whose size is roughly mid-way between the existing Kupe and Pohokura fields.

The second scenario sensitivity is carbon prices. A range of different carbon prices were examined as set out in Figure 2 below, with the levels for the Mid and Hi scenarios being set with reference to estimates of the prices required to meet the Paris Agreement and Net-Zero-NZ by 2050.

Figure 2: carbon price scenarios[2]

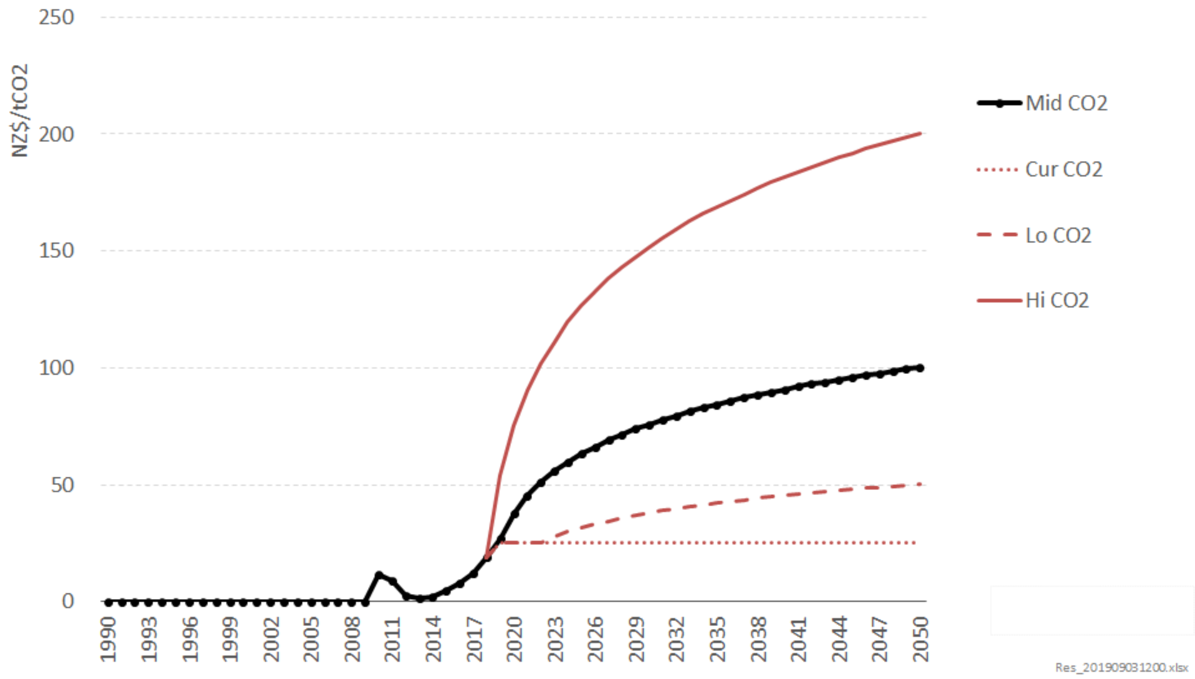


Table 1 shows how the gas resource and carbon price scenarios have been combined into 'composite' scenarios.

Table 1: Composite market scenarios

Composite scenario	Carbon price scenario	Resources scenario
Reference	Mid	Central
Cur CO_2	Cur CO2	Central
Lo CO_2	Low	Central
Hi CO_2	High	Central
Lo Resources	Mid	Low
Hi Resources	Mid	High
New Offshore	Mid	Cen res + New offshore

[2] The 'Cur CO_2' scenario represents a continuation of the current NZ$25/t$CO_2$ carbon price.

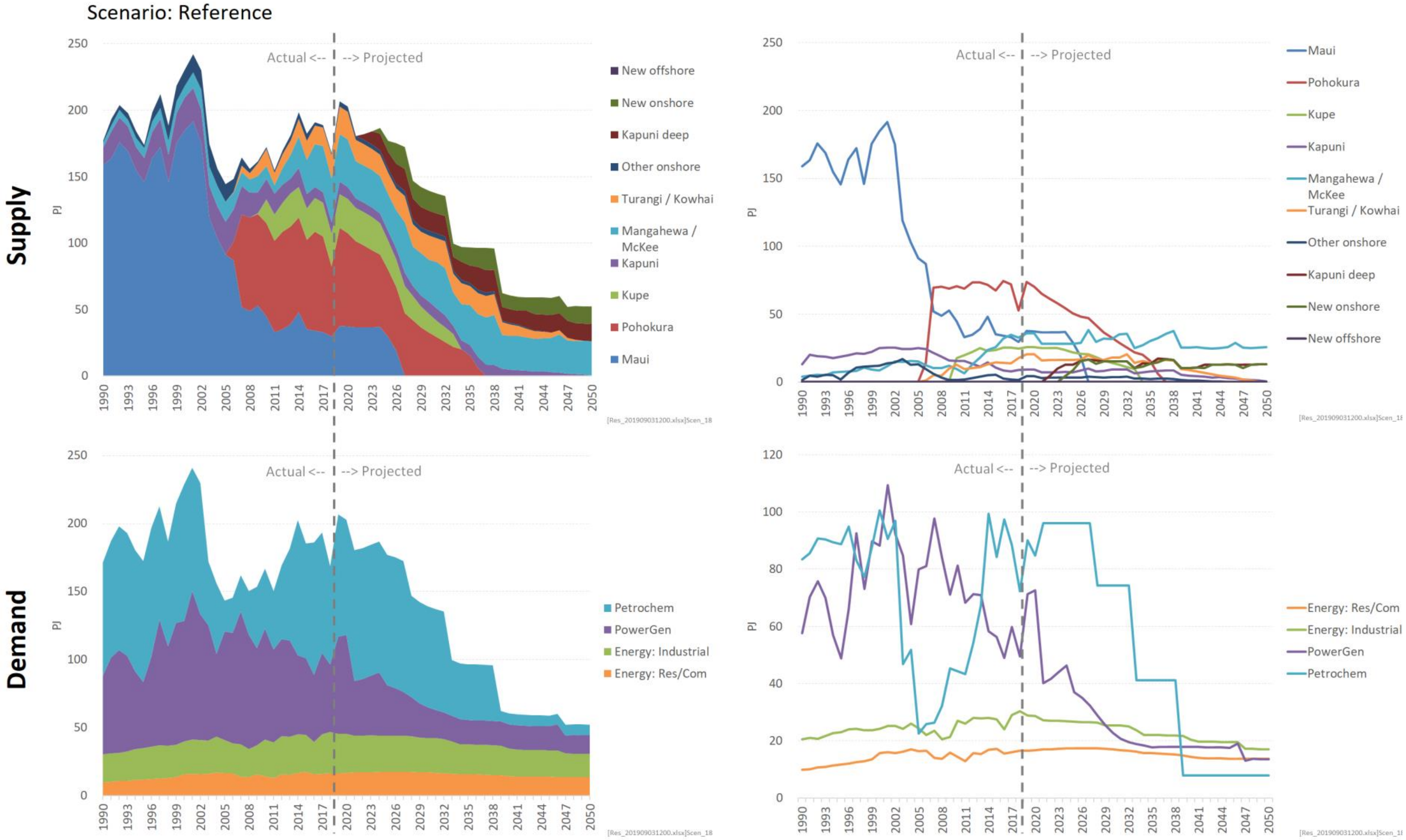
Results for Reference scenario

Figure 3 below shows the summary projections for the reference scenario, which comprises the Mid carbon price plus Central resources scenarios. It indicates:

- Petrochemical production continues at current levels until the middle of the next decade, at which point the sector progressively exits New Zealand over the course of the following fifteen years due to the remaining offshore gas fields reaching the end of their life (Pohokura, Maui and Kupe) and price rationing to postpone the time when higher-cost LNG imports would be required.
- Baseload gas-fired power generation exits within the next five years due to displacement by new, cheaper renewable power generation.[3] Some peaking generation which performs some seasonal / dry-year balancing is also progressively displaced over the subsequent 15 years. However, a rump of peaking generation remains to perform very low-capacity factor seasonal / dry-year peaking. Gas-fired cogeneration also remains. The replacement of baseload gas generation causes the % of renewable generation to rise to 90%, and it steadily rises to almost 98% by the end of the projection.
- Industrial process heat and residential & commercial heating demand exhibits some slight decline. The price rationing effect of the lower-value segments of petrochemical and baseload gas-fired generation exiting New Zealand prevents any significant resource availability-driven reductions in industrial process heat demand, but some carbon-price-driven fuel-switching starts to occur towards the end of the projection.
- Some new onshore fields are found and developed, driven by the tightening of gas supply with the end-of-life of the offshore fields.

[3] The cost of renewables falls below the cost of existing baseload gas-fired generation due to a combination of ongoing reductions in the price of new renewables, plus increases in the cost of gas-fired generation – particularly due to rising carbon prices.

Figure 3: Reference scenario projections of supply and demand



Sensitivity of outcomes to variations in resource availability and carbon price

Figure 4 and Figure 5 plot the total demand from each sector for the years 2019 to 2050, and how this varies according to the scenarios of available gas resources (Figure 4) and carbon price (Figure 5).

Figure 4: Resource-availability-scenario-driven variation in total demand to 2050 by sector

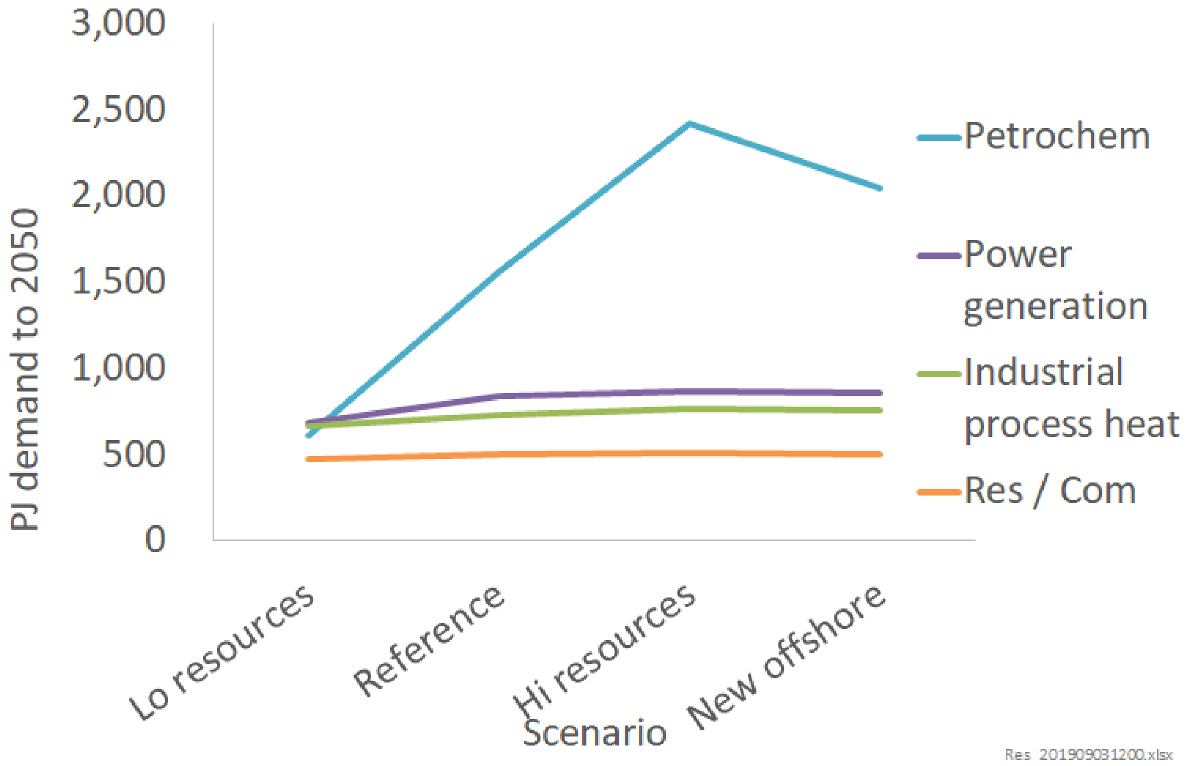
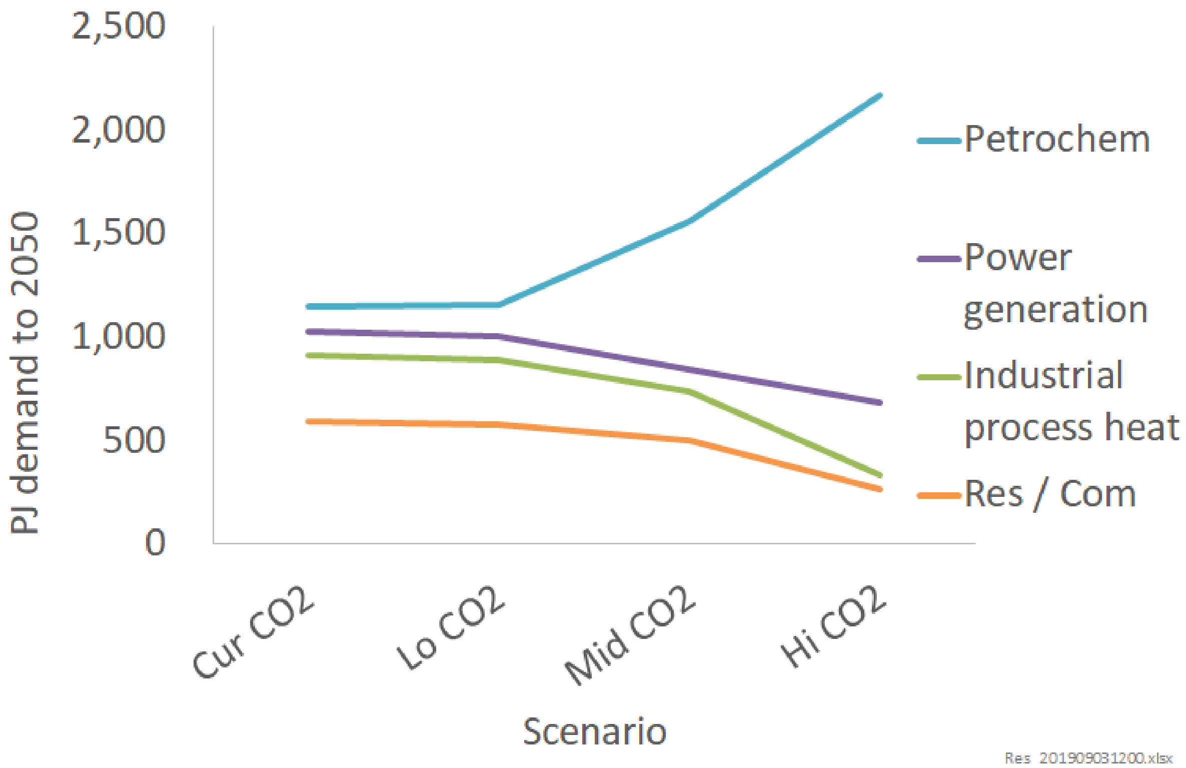


Figure 5: Carbon-price-scenario-driven variation in total demand to 2050 by sector



- ***Petrochemical demand*** (methanol and urea) is the sector which is most sensitive to resource availability. The exit of the first two methanol trains is driven by the timing of the end-of-life of the three remaining offshore fields, and the exit of the last methanol train is driven by price rationing to postpone the time when higher-cost LNG imports would be required once remaining onshore resources become depleted. Price rationing then results in the eventual exit of the urea-production plant in the Lo resources scenario.

  Petrochemical demand is *positively* correlated with carbon prices. This is due to a reduction in gas demand by non-petrochemical sectors in high carbon price scenarios, thereby making more gas available for petrochemical production which doesn't face the same carbon price due to the Industrial Allocation mechanism.[4]

- Different types of ***gas-fired generation*** are the most and least-sensitive to carbon price.
  - Baseload gas-fired generation is the most sensitive of all demand sectors to carbon price, with variations in carbon price dictating when (not whether) such generation is displaced by renewable technologies such as wind and geothermal, whose costs are projected to continue to fall (particularly for wind). Even with a continuation of the current \$25/tCO_2 carbon price, baseload generation is likely to be displaced by the middle of the next decade.
  - Peaking generation is much less sensitive to carbon price, with a rump of gas-fired peaking generation that is used infrequently during dry winters being the highest value use of gas in New Zealand. Even in the high carbon price scenario, our modelling indicates it would not be economic to go above 98% renewable generation by 2050. A rump of peaking gas-fired generation is required to balance variable renewable generation (particularly hydro). This keeps electricity costs lower and supports greater whole-of-economy decarbonisation through electrification – particularly for transport and process heat. These quantitative and qualitative results are consistent with the Interim Climate Change Commission's report on moving towards higher proportions of renewables.
  - Gas-fired cogeneration for industrial process heat also requires a high carbon price for it to be economic to switch.

  Baseload gas-fired generation exhibits some sensitivity to scenarios around resource availability, but peaking generation is largely insensitive to this variable with other, lower-value demand segments performing the rationing to respond to variations in available gas.

- Demand for ***Industrial process heat*** and ***space & water heating for residential & commercial consumers*** is sensitive to carbon prices above \$80-\$100/tCO_2. If carbon prices are below these levels, industrial process heat gas demand is likely to remain flat, while residential & commercial demand is likely to grow – driven by population growth. In the high carbon price scenario, gas demand for these segments drops to less than 10% of current levels by 2050. This is driven by switching to lower-carbon alternatives such as biomass (for process heat) and electric heating (for all sectors).

  Demand for these segments is much less sensitive to variations in resource availability for the period modelled (out to 2050), with petrochemical demand performing the bulk of price rationing to respond to variations in resource availability.

[4] If the support under the Industrial Allocation mechanism were withdrawn *and* overseas methanol producers didn't face a cost of carbon, our analysis indicates that New Zealand methanol production would exit in futures of high New Zealand carbon prices. The reduced New Zealand production would most likely be replaced by gas- and coal-based overseas methanol production, likely leading to an increase in global carbon emissions.

Broader implications for consumer prices

In terms of wholesale gas pricing outcomes, as long as petrochemical production continues to operate within New Zealand, medium to long-term wholesale gas prices are likely to be similar to those experienced up until early 2018 – i.e. driven by Methanex's willingness-to-pay.

It is considered that the recent situation of high gas prices is strongly driven by a short-term issue of electricity generation capacity shortfall and gas deliverability shortfall, rather than any structural change in the gas market. These deliverability issues are likely to be substantially addressed over the next couple of years by investment in both renewable generation capacity and upstream deliverability.

After petrochemical plant has exited from New Zealand, wholesale gas prices will be driven by the willingness-to-pay of the marginal (in a long-run economic sense) source of demand. This is industrial process heat demand (noting that baseload power generation will already have exited). Although industrial process heat demand has a much higher current willingness-to-pay than petrochemical demand, this willingness-to-pay for gas will fall with rising carbon prices – with the rate of reduction being $1/GJ for every $19/t$CO_2$e increase in carbon prices.

The effect of this, and the progressive price rationing effect from demand defection from the most price-sensitive segment of industrial process heat, significantly limits increases in wholesale gas prices. Accordingly, the greatest long-term price uncertainty facing the likes of industrial gas consumers relates to carbon price, not gas price. If carbon price remains at current levels it would not be cost-effective to switch to low-carbon alternatives. However, our whole-of-economy modelling indicates that this would mean New Zealand would not meet its net-zero-by-2050 target.

If carbon prices rise to the level which our modelling indicates is necessary to meet this net-zero target (and which are also consistent with other international studies of the international prices required to meet the Paris Agreement targets), then it would be economic for most industrial process heat gas consumers to switch to biomass or electrification.

A similar dynamic applies to residential and commercial gas consumers – albeit with some complex factors which make projection of outcomes more difficult:

- In general, the carbon price required for it to be economic to switch away from gas for residential & commercial consumers is much higher than for industrial consumers. However, if the retirement of carbon-price-sensitive industrial consumers[5] results in gas pipeline owners seeking to recover this 'lost' revenue by increasing prices to residential and commercial consumers, this could magnify the effective carbon price to residential and commercial consumers. That said, our modelling indicates that there are limits to the extent to which pipeline owners will be able to do this, as this can lead to a rapid 'death-spiral' effect.
- Further, non-price factors are significantly greater drivers of mass-market consumer decisions. It is likely that a future with greater climate-change sensitivity will see many consumers increasingly basing their fuel choices on environmental factors as well as economic factors.

Flexibility

While baseload gas prices are only projected to increase modestly (excluding the cost of carbon), it is possible that the cost of providing low capacity factor gas (principally required for winter space heating demand and gas-fired peaking generation) could rise more significantly. This is due to the

[5] The exit of petrochemical demand will have little impact on gas network cost recovery as the close-to-wellhead location of such demand means that the petrochemical sector contributes little to current network cost recovery. Likewise, the exit of the Taranaki-located TCC baseload gas-fired generator will not have major impact on gas network revenues, but the Huntly-located e3p baseload gas-fired generation will have slightly greater network revenue impact.

loss of resources that have historically provided a lot of energy flexibility – particularly the Maui gas field, and the potential exit of Huntly coal-fired generation. The exit of methanol production would also remove a source of energy flexibility able to address extreme situations of scarcity.

Offsetting this reduction in the supply of flexible fossil-energy resources could be a reduction in the demand for flexible energy due to the 'over-build' of renewable generation. Depending on the extent of over-build this could significantly reduce (but not eliminate) the need for gas-fired generation to provide seasonal and dry-year swing.

Other factors could also materially alter the supply / demand balance for energy flexibility on different timeframes, including:

- Investment to improve the injection & extraction rates for the Ahuroa gas-storage facility; and
- Large-scale battery deployments – particularly in a mass fleet of EV vehicles.
- Climate change reducing the seasonal difference between winter heating and summer cooling demand.

Our modelling has sought to capture at a high-level the effect of many of these factors – particularly the relative costs of providing energy flexibility from gas-fired versus coal-fired generation, and the extent to which over-build of renewables will reduce the need for flexible energy. However, detailed exploration of all of the above factors and the implications on the price of gas for flexible uses, was beyond the scope of this study.

1 Purpose and structure of report

1.1 Purpose

This 2019 Gas Supply and Demand study is the fourth in a series of periodic reports commissioned by Gas Industry Company. These Supply / Demand studies:

- analyse the long-term drivers of outcomes in the New Zealand gas industry – both the upstream supply-side of the industry, and the various demand segments
- develop long-term projections of possible futures for the sector, based on modelling of the key sector drivers identified in the study.

The purpose of these studies is to facilitate informed decision-making by stakeholders in all parts of the gas sector (upstream, midstream, downstream, consumers, regulators, and government).

Each study has had a similar general purpose. However, each study has also explored certain issues in more detail that have been of importance at the time. The key issues explored in this study are:

- The end-of-life of some of New Zealand's largest gas-producing fields occurring within the next 10 to 15 years, and the economic factors and policy settings driving possible development of new fields.
- The implications of various climate-change-related policies including:
  - Altered oil & gas exploration policy settings
  - Higher potential carbon prices
  - The policy goals of achieving:
    - 100% renewable electricity generation by 2035 (in a normal hydrological year); and
    - net-zero carbon emissions by 2050.[6]

The issues receiving special focus in the previous studies are summarised in Table 2.

Table 2: Issues in focus for past Gas Supply and Demand studies

Version	Issues in focus
2016	• low oil prices • major changes in the power generation sector (potential closure of Tiwai aluminium smelter or Huntly power station)
2014	• power generation sector • more detailed projections of gas outcomes
2012	• peak capacity issues • network investment and capacity allocation on the northern gas transmission system

[6] 'Net-zero' emissions are calculated as gross emissions less any emissions sequestered due to actions such as planting trees.

Although the principal focus of this study is on analysing the key long-term drivers of outcomes in the gas sector, this report also comments at a relatively high level on the supply deliverability / flexibility issues which have been causing some recent challenges in the market.

1.2 Structure of this report

- Section 2 analyses the factors driving upstream gas supply and sets out possible scenarios for additional gas reserves that could be developed to meet future demand
- Section 3 summarises the key factors affecting demand from different sectors of gas users, drawing upon the more detailed sectoral analyses set out in section 6 in the appendices.
- Section 4 sets out projections for aggregate gas demand and supply under a range of scenarios that explore possible futures for CO_2 price and gas reserves.
- Section 5 addresses at a high-level some of the current issues associated with supply deliverability / flexibility.

2 Gas Supply

This section analyses the factors driving upstream gas supply and sets out possible scenarios for additional gas reserves and resources that could be developed to meet future demand. These scenarios form the basis of the detailed modelling described later in section 4.

2.1 A brief history of New Zealand's gas industry

In the 1960's New Zealand started exploring for oil. This resulted in two major discoveries:

- the Kapuni field in on-shore Taranaki which was discovered and developed in the 1960's; and
- the large Maui field in offshore Taranaki, discovered approximately a decade later.

These two discoveries were very rich in natural gas. Indeed, in energy terms, approximately 75% of the hydrocarbons in those fields were natural gas. To extract and sell the oil, New Zealand also needed to extract and sell the gas. However, with no physical connection to the rest of the world (either by pipeline or liquified natural gas (LNG) export facility), there were no ready markets for such gas.

Accordingly, as part of the so-called 'Think Big' initiatives of the time, major investments in gas-using industries were undertaken, particularly petrochemical production in on-shore Taranaki (for methanol, synthetic petrol, and urea) and gas-fired power generation.

Over time, other gas demand developed, particularly for industrial process heat, and, through the conversion of the coal gas (a.k.a. 'town gas')[7] networks to natural gas, residential and commercial demand for space and water heating. Gas transmission pipelines were developed to take gas from Taranaki to the main population centres in the North Island. No gas pipelines were developed to take gas to the South Island, with the result that New Zealand's natural gas-using consumer sectors are solely in the North Island.

From the 1970's through to the early 2000's, New Zealand's gas supply was almost entirely met by the Maui and Kapuni gas fields. No new gas fields were developed during this period, largely because New Zealand's sector was demand-limited. That is, all existing demand was met by Maui and Kapuni and, unless a 'mammoth' discovery of a size similar to Maui was made[8], it would not be economic to develop additional demand through the development of additional petrochemical industries.

In 2002, the owners[9] of the Maui field undertook a technical re-evaluation of likely remaining undeveloped gas within the field. This 'redetermination' substantially reduced the assessed remaining reserves in the Maui field and pushed the New Zealand gas sector into a position of relative tightness. This tighter position, and associated higher prices for gas, resulted in the development of new gas fields, particularly the offshore Pohokura and Kupe fields, and the onshore Mangahewa and Turangi fields.

---

[7] Coal gas was produced by applying a mixture of heat, pressure and chemicals to coal to release a variety of calorific gases used for lighting and heating.

[8] When it was discovered, the Maui gas field was the eighth largest find in the world. (It has since been superseded from that spot by several subsequent larger discoveries around the world).
Experts consider that the Maui field is likely to be the largest field in the Taranaki basin, and that any subsequent discoveries in the Taranaki basin are likely to be substantially smaller.

[9] In this report we colloquially refer to field 'owners' as the parties who have been granted the permits to mine the resource. Strictly speaking the Crown is the owner of the resource.

All but the Turangi field had been discovered before the Maui redetermination announcement (noting that exploration for *oil* continued throughout this period), but not developed previously due to New Zealand's demand being fully satisfied by Maui and Kapuni gas.

Although the significant reduction in Maui supply brought forward the development of these new gas fields, the long development time for a gas field meant that New Zealand had a significant reduction in gas supply between 2003 and 2013.

This supply reduction resulted in a reduction in demand from two key demand sectors:

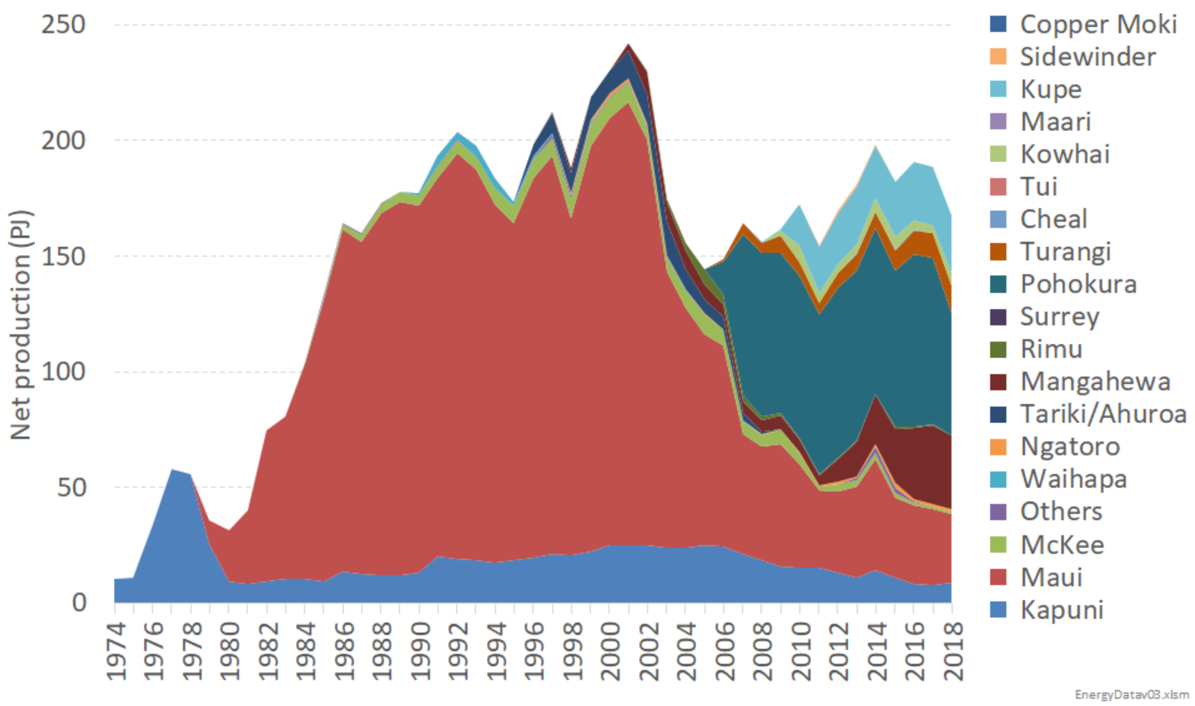
- Petrochemical production, with the significant scaling back of methanol production by Methanex
- Power generation, with Huntly power station largely switching to coal instead of gas, plus in the latter part of this period, some displacement of baseload gas-fired generation through the building of geothermal and wind power stations.

With the progressive development of new gas fields from 2006 onwards, New Zealand gradually increased its gas supply, and petrochemical production progressively ramped back up to reach full capacity from 2013/14 onwards as New Zealand re-established its 'fully-fuelled' position.

Unlike petrochemicals, gas-fired generation did not materially increase to previous levels. Investments in new renewable generation, as well as largely flat electricity demand from 2008 through till 2018, led to the retirement of some baseload gas-fired stations.

This history of changing supply and demand, and associated changes in gas prices, are shown in the following figures.

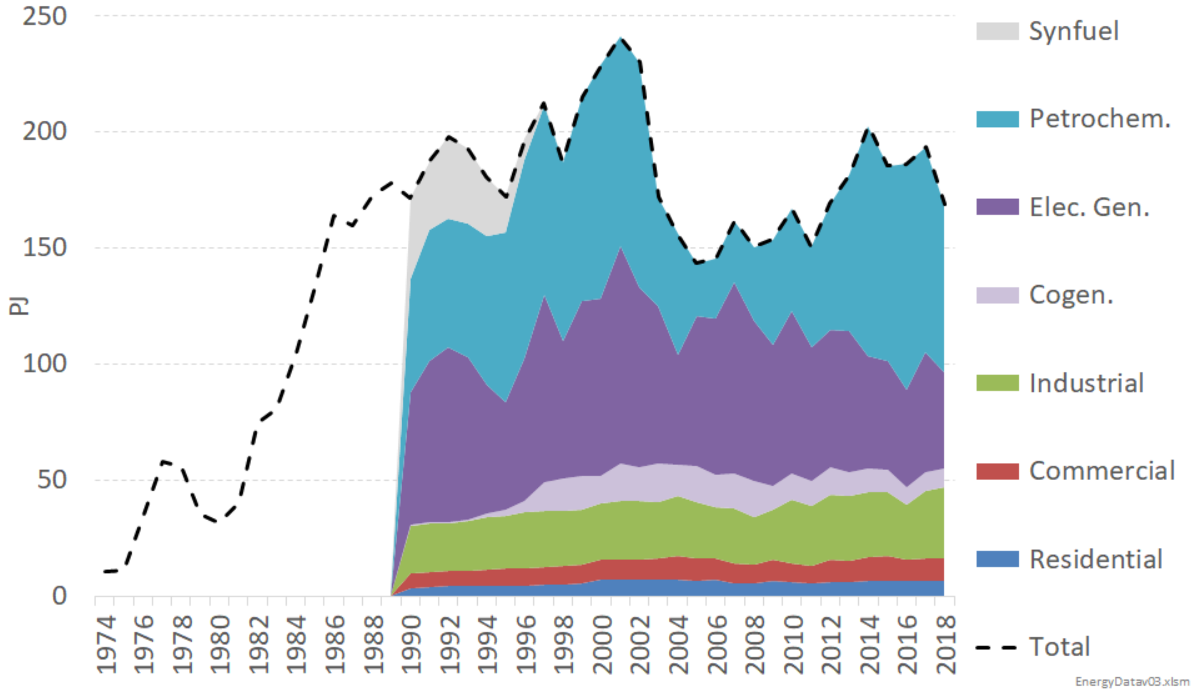
Figure 6: Historical gas production in New Zealand by field[10]



Source: Concept analysis of MBIE data

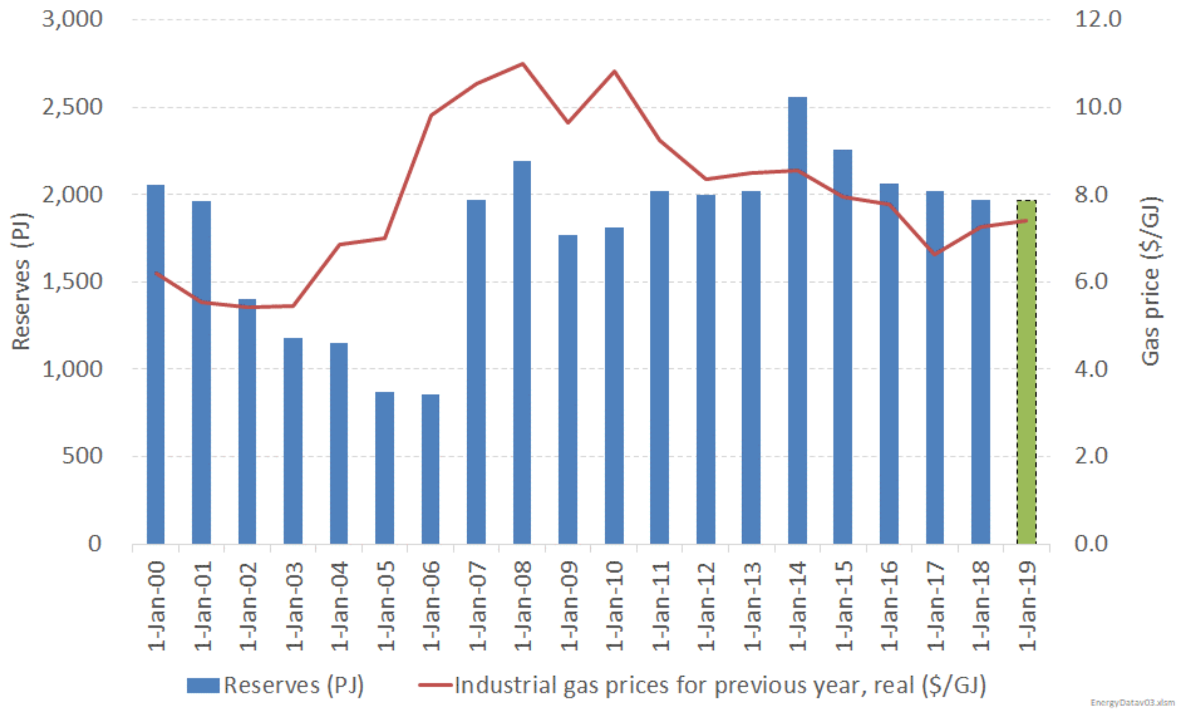
[10] The significant reduction in 2018 was due to a technical issue at the Pohokura field affecting production. Given that Pohokura is New Zealand's largest gas-producing field, this led to relative shortage, with petrochemical demand scaling back until the issues were resolved.

Figure 7: Historical gas demand by key segment[11]



Source: Concept analysis of MBIE data

Figure 8: Historical changes in New Zealand's remaining 2P reserves and industrial gas prices



Source: Concept analysis of MBIE data

[11] 'Synfuel' refers to the production of synthetic petrol. 'Petrochem' refers to the production of methanol and urea. 'Elec gen' refers to gas-fired power generation other than gas-fired cogeneration of electricity and heat which is labelled 'Cogen.'

2.2 Drivers for future gas development

Every year, gas field operators are required to report how much gas (and oil) they have left. The principal number that is reported is the estimate of remaining reserves. Reserves are accumulations of gas and oil which are anticipated to be commercially recovered. This includes accumulations for which development investment has already been undertaken (both development of a processing facility and drilling of wells) or where the field operator has a firm intention to make such investment. The central estimate of the quantity of gas available is often referred to as the '2P' number which represents the 50th percentile estimate of the physical quantity of reserves in a field. (See Box 1 below for more detail on this classification).

As at 1 January 2019, the total of New Zealand's reported gas reserves was just over 2,000 PJ. Given average annual demand of approximately 200 PJ, this implies New Zealand has ten years' worth of gas remaining if demand were to continue at current levels.

However, this *reserves* figure is only part of the remaining gas left in existing fields. Field operators are also required to report estimates of *contingent resources*. These are additional gas accumulations which are estimated to exist and capable of being recovered using today's technology, but for which investment in their development (e.g. in wells) is not deemed commercially viable at the current time.

When the 50th percentile estimate of contingent resources are added (the '2C' number), the remaining developable quantity of gas in New Zealand's fields doubles, to almost 4,300 PJ.

This categorisation of a field's gas (and oil) into different categories (as set out in more detail in Box 1 below) highlights that petroleum development isn't simply a question of drilling a well and building a processing facility at the start of the field's development, and then opening the tap until all the petroleum is extracted.

Instead, development of petroleum from a field requires constant investment – particularly in wells. Over the life of a field, multiple wells may be drilled as output from early wells declines, requiring the drilling of new wells in different parts of the field structure. Further, periodic 'intervention' investment is generally required in existing wells once output levels have declined below threshold levels to partially restore output levels.[12]

The extent of well investment required, and the pattern of well intervention undertaken, vary significantly between fields. For example, the reservoir characteristics of the fields in offshore Taranaki mean that relatively few wells are required, with each well producing large quantities of gas over its lifetime. In contrast, the 'tight' nature of the petroleum reservoirs in onshore Taranaki requires five to ten times more wells to be drilled to produce an equivalent amount of gas.

Given this pattern of required ongoing investment, it only makes commercial sense to commit to such an investment if there is a ready market for gas. Given the demand-limited nature of New Zealand's gas market, some development investment will only occur once supply from existing well investment is no longer capable of meeting demand. Such investment generally occurs slightly before it is needed to prevent situations of temporary shortfall.

[12] This pattern of decline in well output is due to pressure decline as the petroleum is extracted, as well as gradually deteriorating physical condition of the well (e.g. due to accumulation of mineral deposits around the well).

Box 1: Classification of petroleum reserves and resources

Petroleum field operators must compile their reports of their remaining gas and oil in accordance with the internationally recognised Petroleum Resources Management System, published by the Society of Petroleum Engineers (SPE). There are three categories under the SPE classification system:[13]

- **Reserves ('P')**, which are known accumulations of oil and gas that are anticipated to be both technically and commercially recoverable with today's technology. This might include gas that will come from wells that have been drilled, or that field operators have a firm intention to drill.
- **Contingent resources ('C')**, which are estimates of oil and gas that are technically recoverable with today's technology, but not considered commercial at present. The definition of commerciality for an accumulation will vary according to local conditions and circumstances.
- **Prospective resources ('U')**, which are quantities of oil and gas that are estimated to be potentially recoverable, but have not been discovered yet. Such estimates may be based on high-level statistical evaluations (effectively extrapolating based on other discoveries in a basin), through to estimates with greater degrees of confidence based on actual seismic data.

Within each category, there is further subdivision based on the assessed level of uncertainty associated with an estimate. For reserves the three main categories are 'Proven' (1P) being a 90 per cent probability, 'Probable' (2P) being a 50 per cent probability, and 'Possible' (3P) being a 10 per cent probability. There are similar 1C / 2C / 3C and 1U / 2U / 3U subdivisions for contingent and prospective resources.

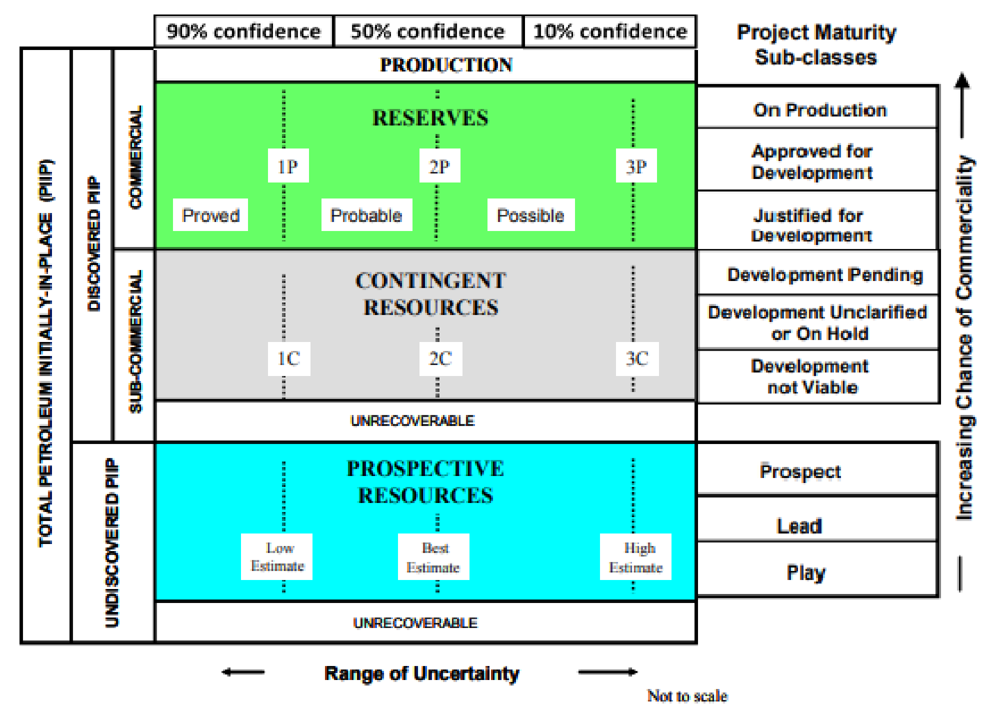
The SPE classification also defines Unrecoverable Resources as those estimated not to be recoverable by future development projects for technical or commercial reasons.

Together, these categories make up the total petroleum in place.

The matrix of categories is shown in Figure 9.

[13] See http://www.spe.org/industry/petroleum-resources-classification-system-definitions.php. Reference should be made to the full SPE/WPC Petroleum Reserves Definitions for the complete definitions and guidelines.

Figure 9: Matrix of reserve and resource classifications



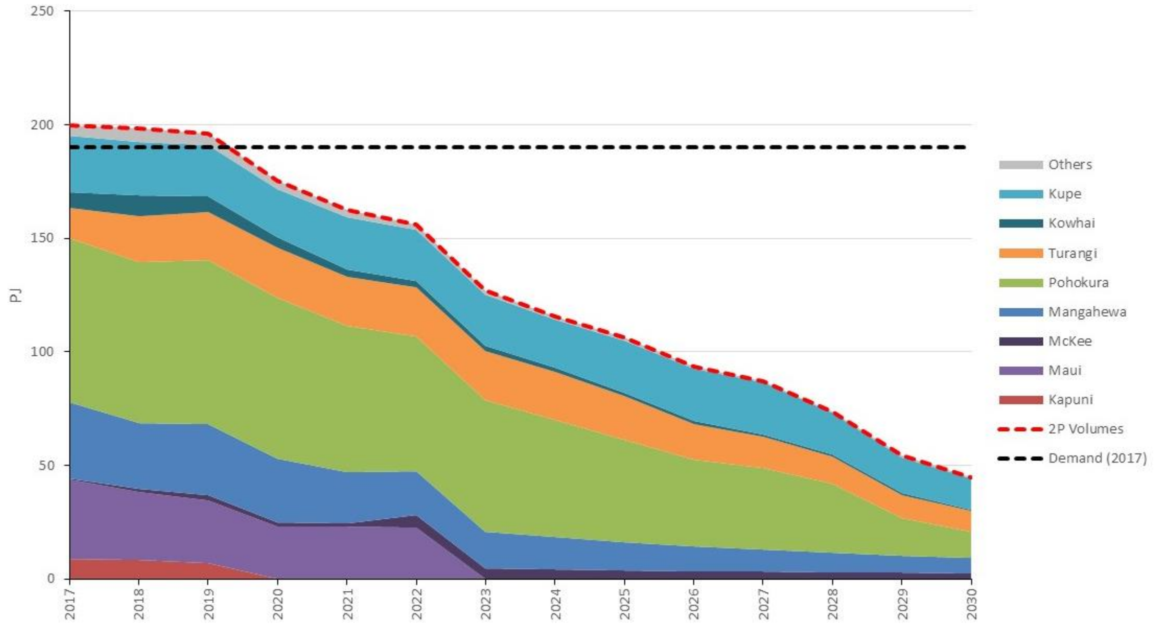
Source: Concept manipulation of Petroleum Resources Management System, Society of Petroleum Engineers diagrams

At first glance, the fact that current reserves can meet current demand for ten years would imply that investment to develop contingent resources would only be required in ten years' time.

However, the fact that production from wells shows a pattern of constant decline means that supply deliverability from wells producing gas from petroleum classified as reserves will typically start to fall-short of the demand for gas far sooner than that.

This is illustrated in Figure 10 which shows a 2018 projection produced by the Petroleum Exploration and Production Association of New Zealand (PEPANZ) of the likely production profiles from gas classified as 2P reserves.

Figure 10: 2018 PEPANZ projection of likely gas production from 2P reserves[14]

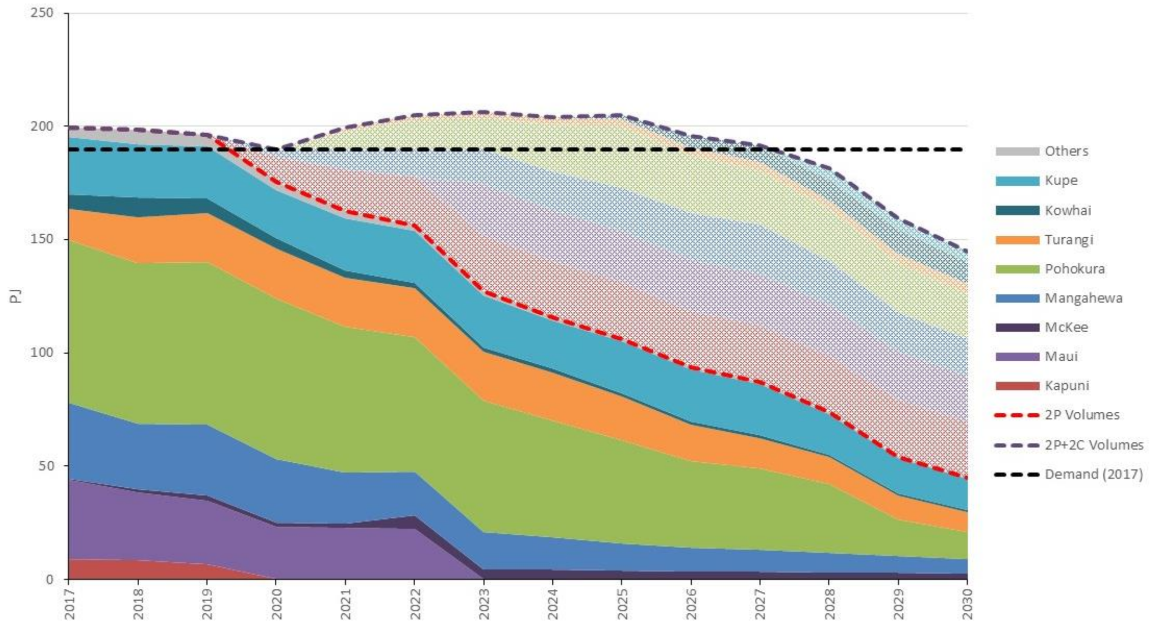


Source: PEPANZ

Figure 10 highlights a projected gap from 2020 between available supply from existing reserves and likely demand from industrial, commercial and residential users, plus gas-fired power generation operating at levels consistent with recent years and petrochemical production operating at full capacity.

In the same projection, PEPANZ indicated that such a gap could potentially be addressed through investment in the development of contingent resources from existing fields. This is shown in Figure 11 below.

Figure 11: 2018 PEPANZ projection of possible gas production from 2P reserves plus 2C resources



Source: PEPANZ

[14] "M&M" refers to the McKee plus Mangahewa fields in onshore Taranaki.

This analysis from PEPANZ indicated that, if demand is to continue at current levels and was willing to pay the amount required to support development of contingent resources, then investment in the development of contingent resources from existing fields could deliver sufficient gas supply to meet demand at current levels until the latter part of the next decade.

However, development of contingent resources can't maintain output at current levels forever. Eventually, depletion of reserves and resources from existing fields will reach a point where new sources of gas will need to be found and developed if output is to continue to meet current levels of demand. Figure 11 indicates that this could happen towards the latter part of the next decade – albeit noting that such projections are subject to inherent degrees of uncertainty.

This raises two key questions:

- How much undiscovered gas is likely to be found and developed in future years?
- Is future demand for gas likely to remain at current levels?

The answers to both questions are strongly inter-linked, as gas supply will only be developed if there is sufficient gas demand willing to pay as least as much as it costs to develop it. To unpick this question, the remainder of this report addresses:

- How much additional gas could be discovered over the next few decades? This question is addressed in section 2.3.
- How much would it cost to develop such new discoveries – and to develop the contingent resources from existing fields? This issue is addressed in section 2.4.
- Will New Zealand's gas consuming sectors be willing / able to pay for gas at the level required to bring forward such development – particularly if rising carbon prices increase the effective cost of gas? This is addressed in section 3.
- How will the interplay between the scale of potential additional resource (and cost of development) and the scale of potential demand (and willingness to pay) drive outcomes for New Zealand's gas sector over coming decades? This is addressed in section 4, with modelling undertaken to develop potential projections of supply and demand for gas out to 2050.

2.3 How much gas could be developed to meet future demand?

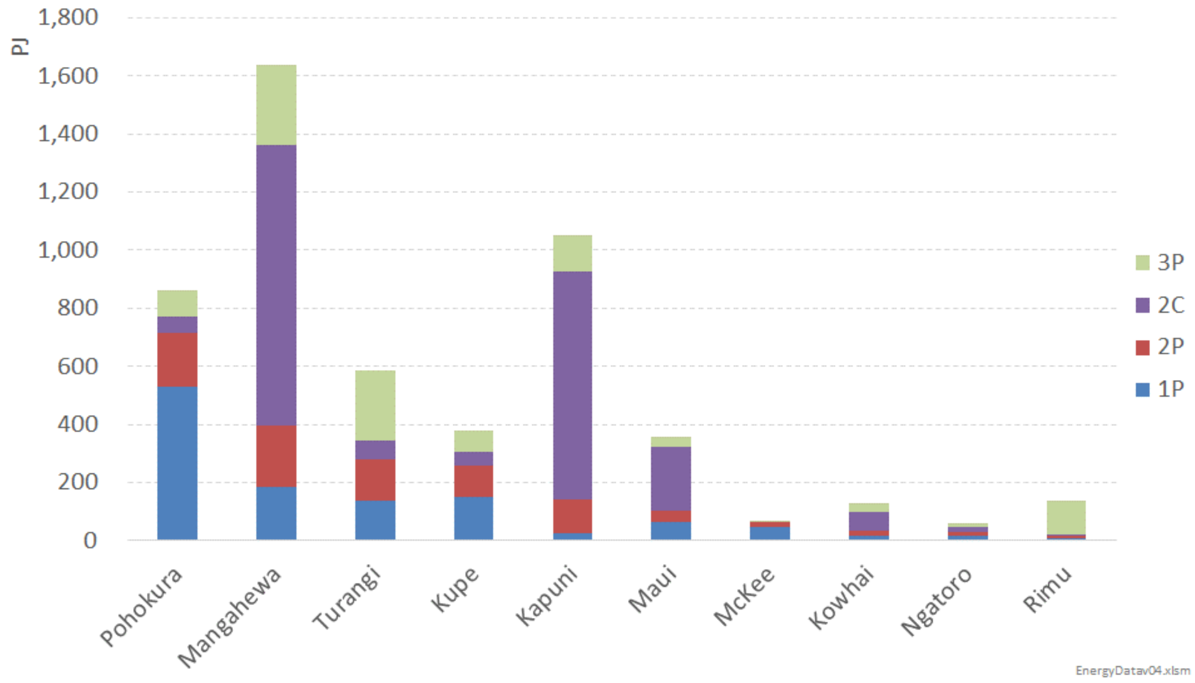
One of the key inputs into our modelling of potential outcomes for New Zealand's gas sector are assumptions about the extent of future gas that could be developed to meet future demand.

Sub-section 2.3.1 describes our analysis of the potential additional gas that could be developed from existing fields, with sub-section 2.3.2 setting out the analysis of the possible gas that could come from as-yet-undiscovered fields.

2.3.1 How much additional gas could be developed from existing fields?

Figure 12 shows the latest published estimates by field owners of their remaining reserves and contingent resources for existing fields as at 1 January 2019.

Figure 12: Published estimates of remaining reserves and contingent resources for existing fields as at 1 January 2019[15]



Source: Concept analysis of MBIE data

We use the sum of the 2P and 2C numbers across all fields as the starting point for our Central estimate of the scale of reserves and resources from existing fields that could potentially be developed to meet future demand.

However, we have also sought to take account of the fact that there may be some other factors which impact whether an accumulation classed as contingent will be developed or not. For example, possible uncertainty around future consenting, or uncertainty over the cost of development for accumulations which have had little or no exploratory wells developed. Based on advice from an external geologist advisor to GIC we have factored the 2C numbers by 75%.

Thus, our Central scenario for the scale of additional reserves and resources that *could be developed* from each field to meet possible future demand = 2P + 75% * 2C. The italicisation of "could be developed" is to stress that our modelling only projects these resources actually being developed in the future if the modelling of the demand side sectors (as set out in section 3) indicates that their willingness-to-pay in the future (factored by factors such as the carbon price) is greater than the cost of developing these reserves and resources.

Our modelling also addresses the uncertainty over the scale of additional reserves and resources that could be developed, through developing Low and High scenarios. We use the published 1P/3P and 1C/3C numbers as the basis for developing these sensitivity scenarios.

[15] The columns have been formatted and ordered so they are additive. Thus, the 2P column represents the *incremental* gas reserves above the 1P value. 2C resources represent the total quantity of 2C resources (noting that there is no reporting of 1C resources). It is therefore appropriate to consider the top of the 2C column as representing the total quantity of reserves and resources with 50% probability of exceedance. The 3P column represents the *incremental* gas reserves above the 2P value. There is no reporting of the 3C value.

The Low reserves scenario for each field is calculated by multiplying the field's 2P number by the ratio of the total New Zealand 1P number to the total New Zealand 2P number. This is repeated for the High scenario using the total New Zealand 3P number. [16]

This gives values which are -15% and +18% of the 2P number, implying a 3P/1P ratio of 1.4.

1C and 3C values are not published by MBIE for contingent resources. However, it is known that they exhibit a similar variation to that for reserves – albeit with the scale of variance materially greater.

Accordingly, in developing Low and High scenarios of contingent resources we have assumed that the percentage scale of variation relative to 2C numbers is twice the percentage variation of 1P and 3P to the 2P numbers. This gives a 3C/1C ratio of 1.9. These contingent resource numbers are also factored by the 75% value used for the 2C estimate to reflect the other factors mentioned above which can impact whether an accumulation classed as contingent will be developed or not.

The last point to note relates to the Kapuni 2C numbers. Unlike the other fields, the majority of this resource relates to a new, deeper accumulation, that is several hundreds of metres beneath the gas deposits that are currently being extracted as part of the Kapuni field. This gives these 'Kapuni Deep' resources some characteristics that are similar to a new field. Accordingly, in the modelling we have separately identified development of 'Kapuni Deep' to the existing 'Kapuni' field.

In the absence of public data, we have made an assumption that 90% of the published 2C values for the Kapuni field relates to Kapuni Deep. This is based on the significant decline in production from the existing Kapuni field, and the assumption that this indicates that the gas from this accumulation are coming to the end of their life.

One aspect of treating this like a new field is assuming that in the Low scenario no new gas is developed from the Kapuni Deep accumulations.

2.3.2 How much gas could be developed from as-yet undiscovered new fields?

We have based our scenarios of the likely extent of future gas that could be developed from as-yet undiscovered fields on modelling undertaken by GNS and MBIE.

In 2015, GNS published a report on the likely potential for additional gas discoveries in New Zealand's petroleum basins.[17]

This report came up with a P50 estimate of undiscovered gas in the Taranaki basin of approximately 6,000 PJ.[18] This volume of gas is equivalent to 30 years' worth of current demand and would be

[16] It would be inappropriate to use the individual 1P and 3P numbers for each field, as this would give a cumulative probability across all of New Zealand's fields which is substantially different to the 90% probability of exceedance and 10% probability of exceedance which the 1P and 3P numbers are meant to represent. For example, the probability of exceedance of the combined 3P numbers for two fields would be 10% * 10% = 1%.

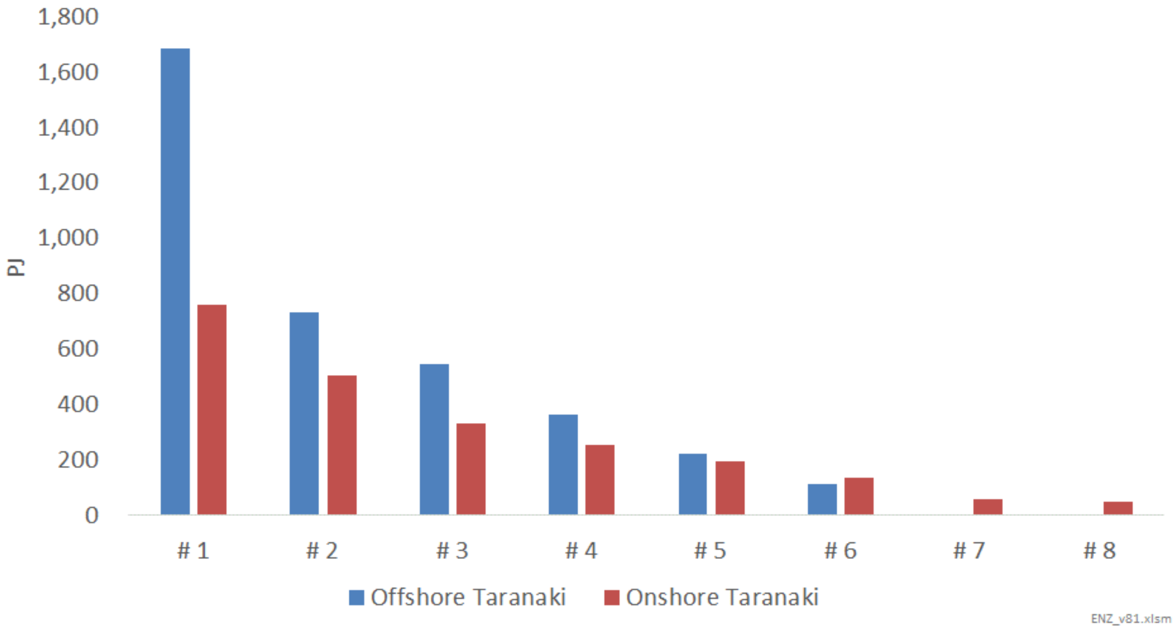
[17] "*Assessment of New Zealand's Undiscovered Petroleum Resources by Delphi Panel*", GNS Science, September 2015. This updated their 2009 work for MBIE.

[18] In developing scenarios for the amount of gas that could be developed from fields that haven't even been discovered yet, we have limited our analysis to potential discoveries in the Taranaki petroleum basin. This covers onshore Taranaki and an area of sea extending hundreds of kilometres out from Taranaki. This is because, as set out in previous gas Supply / Demand studies, even though there are many other petroleum basins in the seas all around New Zealand it would be uneconomic to develop the gas transmission pipelines to bring any such gas to New Zealand's current, Taranaki-centric gas market. Instead, any finds in places such as in the seas off Canterbury or the Great South Basin would most-likely either be developed by developing petrochemical facilities where the gas comes ashore in such places, or it would be developed through floating LNG production vessels with the gas being exported overseas without ever touching New Zealand soil.

additional to the approximately 19 years' worth of current demand represented by reserves and contingent resources from existing fields.

It further indicated that this 6,000 PJ would be spread among a few discrete fields, with its P50 estimate being for six fields in offshore Taranaki, and eight in onshore Taranaki. This distribution is illustrated in Figure 13.

Figure 13: Estimated distribution of size of undiscovered gas fields[19]



Source: Concept analysis and modelling of GNS data

However, the GNS report highlighted that it was extremely unlikely that all this gas would be discovered, never mind developed. This was due to the significant cost of exploration (approximately $80 million for a single offshore exploration well) and the low likelihood of success (GNS estimated 1-in-10 success for an offshore exploration well).

In 2016 MBIE undertook modelling which sought to estimate the likely extent of gas (and oil) discovery and development out to 2050. This modelling was based on the analysis developed by GNS, in conjunction with work it commissioned from Michael Adams Reservoir Engineering on the costs of oil and gas exploration and development. This modelling came up with a mean estimate of additional onshore and offshore Taranaki gas from as-yet-undiscovered fields that would be discovered and developed of approximately 2,250 PJ: 700 PJ from onshore and 1,550 PJ from offshore Taranaki.

The fact that this estimate of how much would be developed is only approximately one-third of the 6,000 PJ GNS estimated would physically exist, reflects the fact that it is extremely unlikely that the majority of petroleum reservoirs in a given basin will be discovered and developed. This is due to

---

[19] To help contextualise the size of these potential fields, the estimated ultimately recoverable size of gas reserves plus contingent resources for existing fields is as follows:

- Offshore
  - Maui = 4,400 PJ
  - Pohokura = 1,600 PJ
  - Kupe = 450 PJ
- Onshore
  - Kapuni (excluding / including Kapuni Deep) = 1,100 / 1920 PJ
  - Turangi = 450 PJ

the inherent difficulties of trying to locate relatively small accumulations of hydrocarbons many kilometres beneath the earth's surface – which is often itself at the bottom of the sea.

Then in April 2018, the government announced an amendment to the Crown Minerals Act 1991 regarding the issuing of future petroleum exploration permits.

Under this amendment, new exploration permits would only be issued for the *onshore* Taranaki region. No new permits would be issued for offshore exploration – either in Taranaki or elsewhere in New Zealand – but existing permits would not be affected with their conditions remaining unchanged.[20]

After this April 2018 announcement, MBIE updated its modelling of the likely extent of future gas discoveries and development from as-yet-undiscovered fields. This indicated a revised estimate of approximately 850 PJ of future gas being developed. Given that exploration settings for onshore Taranaki are unchanged, this indicates that the average extent of discovery and development of offshore Taranaki has fallen from 1,550 PJ to 150 PJ.

Further, it should be appreciated that this 150 PJ represents the *mean* outcome of a range of possible outcomes. Given the distribution of likely undiscovered field sizes shown in Figure 13, this 150 PJ represents the probability-weighted average of a range of possible futures – with the most likely outcome being no new offshore gas discoveries, and a smaller number of possible futures with a relatively large gas discovery of hundreds of PJ.

Given this relatively 'binary' aspect to future offshore gas discoveries, we have developed four scenarios of likely future gas that could be discovered and developed.

- Three scenarios corresponding to our "High / Central / Low" scenarios described in section 2.3.1 previously. These only feature new gas developments from *Onshore* Taranaki discoveries. The Central scenario has 700 PJ of additional undiscovered gas capable of development – our '2U' number. This 700 PJ value is the central number from MBIE's analysis. The Low and High scenarios have a scale of variation which is twice that of the variation in contingent resources set out in section 2.3.1. This gives a 3U/1U ratio of 4.3. For comparison, the GNS report had a 3U/1U ratio for undiscovered gas in the Taranaki basin of 5.8.
- We have an additional 'Offshore gas discovery' scenario. This has the Central value for Onshore Taranaki discoveries but a single additional offshore discovery of 900 PJ – a size that is roughly mid-way between the existing Kupe and Pohokura fields.

[20] Existing exploration permit holders can, under some conditions, still apply to:

- make changes to a work programme
- extend the duration or the land area under permit
- transfer the permit to another party or another operator.

Furthermore, if parties holding offshore exploration permits make a discovery, they will still be able to apply to develop those towards production based on the same application process as previously.
For more information see the Beehive announcement and FAQ at https://www.beehive.govt.nz/release/planning-future-no-new-offshore-oil-and-gas-exploration-permits and https://www.beehive.govt.nz/sites/default/files/2018-04/Planning%20for%20the%20future%20%20Q%20and%20A.pdf

2.3.3 Overall scenarios for the scale of reserves and resources which could potentially meet future demand

Figure 14 and Figure 15 below (showing the same data but in two different formats) combine the different scenarios for the potential extent of additional gas that could be developed from existing and as-yet-undiscovered gas fields.

These four scenarios are a key input into our modelling of New Zealand gas futures set out in section 4.

Figure 14: Scenarios for scale of additional reserves and resources available for development as at 1 Jan 2019 – Split by field

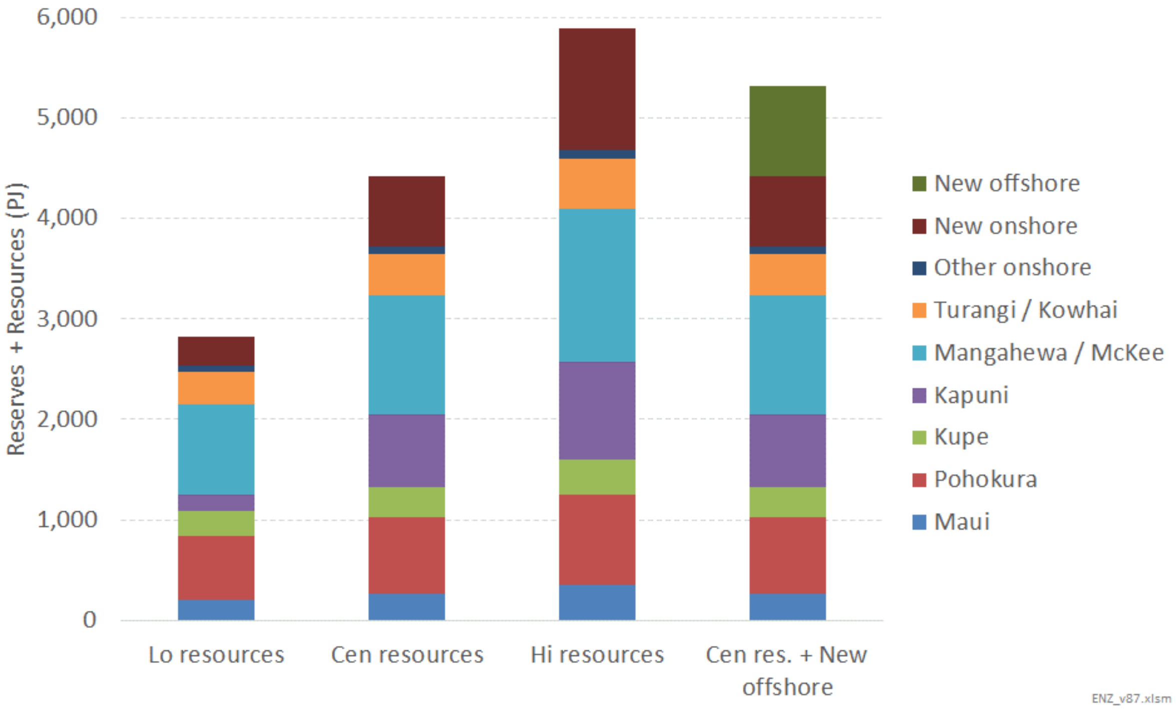
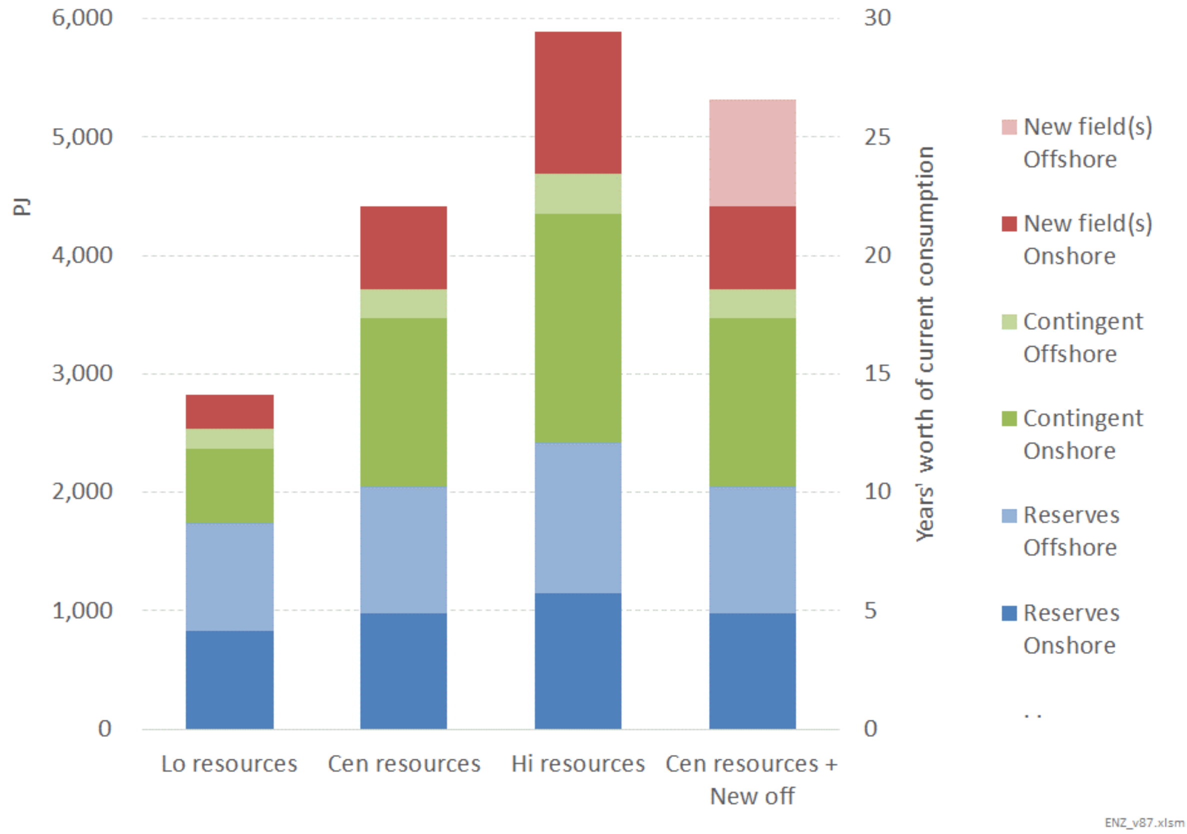


Figure 15: Scenarios for scale of additional reserves and resources available for development as at 1 Jan 2019 – Split by resource category and onshore/offshore



2.4 How much will it cost to develop these additional contingent resources and undiscovered gas fields?

One of the complexities of analysing oil and gas development economics is that the costs of development are very situation specific.

Thus, all the following factors can have a huge bearing on the effective $/GJ cost of developing and producing the petroleum resource:

- the characteristics of the rocks in and above the reservoir;
- the quantity of petroleum resource in the reservoir;
- the depth of the reservoir;
- the location of the field (particularly onshore versus offshore, depth offshore);
- the extent of existing onshore pipeline and/or processing infrastructure; and
- the proportion of gas versus liquids in the petroleum resource.

The scale of this variation was highlighted in the Michael Adams Reservoir Engineering report to MBIE on the costs of finding and developing oil and gas fields. Thus, some fields could have production costs orders of magnitude higher than other fields.

Accordingly, it is not appropriate to say there is "a" $/GJ cost of developing oil and gas fields. Rather, there is a continuum of costs ranging from "relatively low" (i.e. materially lower than average gas prices seen to date) to "very high" (i.e. materially higher than average gas prices seen to date).

These vague phrases are not very helpful in gaining an understanding of the economics of oil and gas exploration. However, it is possible to draw some general conclusions which are useful in considering the likely scale and extent of future gas exploration and development in New Zealand:

- There are significant fixed costs associated with both exploration and development, and such costs exhibit economies of scale. The result of this is that the $/GJ development cost of a field tends to fall in an exponential fashion with the size of the field. Depending on the other characteristics of the fields, this also means that some of the smaller fields that GNS considered likely to exist (as illustrated previously in Figure 13) could be uneconomic to develop if their costs of development are above the price of gas which consumers are willing to pay.
- The costs of developing an offshore field are generally considerably greater than a similar-sized onshore field. This means that the minimum economic size for an offshore field is considerably larger than the minimum economic size for an onshore field.
- There is an optimum sizing of the production assets for a field (wells, associated extraction infrastructure, and processing facilities), leading to an optimum length of time for the field's productive life – typically between 8 to 15 years, with the larger fields having longer productive lives. Producing the petroleum resource at a lower rate using smaller-sized production assets, thereby extending the life of the field, will tend to increase the $/GJ cost of developing the petroleum resource due to losing some of the economies of scale.

  One of the key corollaries from this point and the previous point is that developing a new offshore field will require offtake rates that can only be satisfied by the scale of demand of a large petrochemical producer.
- Because there are significant fixed costs, a material proportion of which are incurred at the start of a field's life:
  - the incremental $/GJ costs of producing reserves (particularly those for which wells have already been drilled) are relatively low
  - the incremental $/GJ costs of developing contingent resources from an existing producing field are generally
    - higher than the incremental $/GJ costs of producing reserves, given that contingent resources generally require additional wells to be drilled; but
    - lower than the overall lifetime $/GJ production costs of the field including the initial upfront development costs.
- After a field has been initially developed, it is hard to materially increase the deliverability (i.e. maximum production capacity) of the field without incurring significant additional capital investment costs in production assets.
- Fields with a higher proportion of liquids require a lower gas price to be economic than fields with low proportions of liquids, all other things being equal. This is because liquid sales will contribute to recovery of a field's fixed costs, with such contribution being proportionally greater if the $/GJ price of oil is greater than the $/GJ price of gas – as has generally been the case to a material extent over the past couple of decades. This also means that the threshold gas price for development of a field to be economic will tend to fall as the oil price rises.

In developing the supply / demand modelling set out in section 4, we have sought to capture the above general dynamics, while noting that field specifics may result in variations in outcome to that modelled.

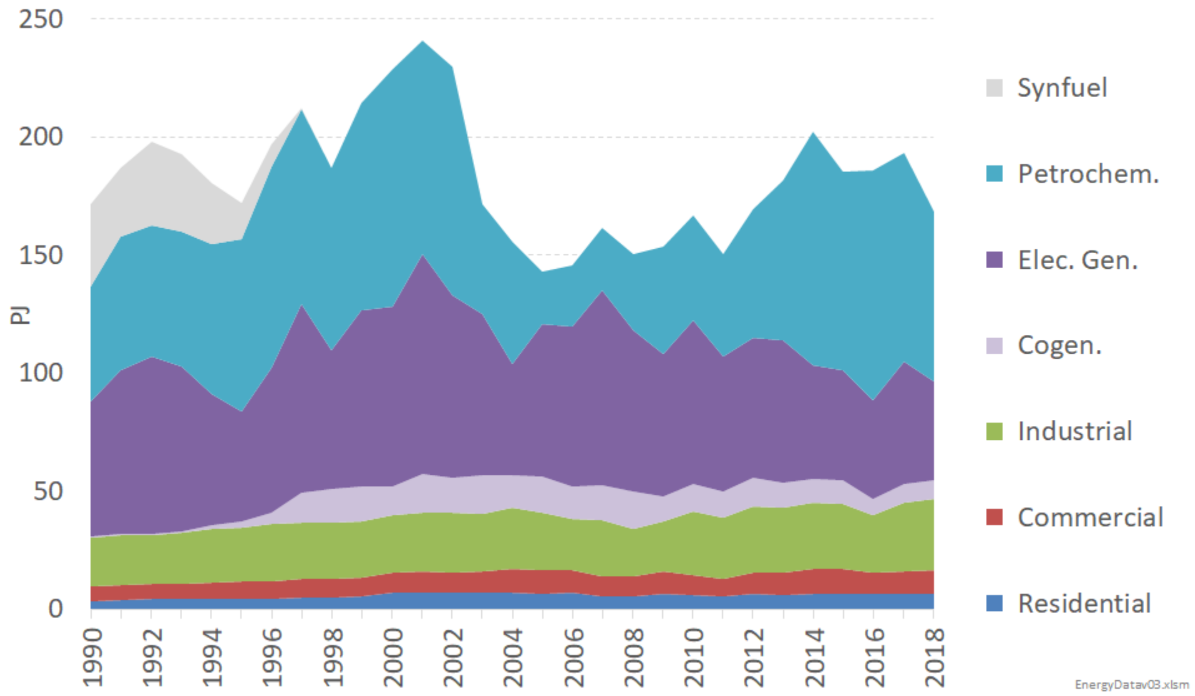
3 Gas Demand

In considering the demand-side of the future New Zealand supply / demand equation, we have split demand into four key segments:

- Mass-market (residential and commercial) use for heating energy (principally space and water heating);
- Industrial use for heating energy (principally process heat);
- Power generation (both electricity-only and cogeneration);
- Petrochemical production (with gas used both as a feedstock and as an energy fuel).[21]

Figure 16 shows how demand from these segments has varied over time.

Figure 16: Historical gas demand from different segments



Source: Concept analysis using MBIE data

In modelling the likely outcomes for these different segments, and their interaction with the supply-side, we have adopted the following framework:

- For the first three segments, we project the demand for the underlying *service* for which gas could be used. i.e.
  - The demand for residential and commercial (space and water heating) is driven by population and GDP growth, and assumptions as to the extent of future energy efficiency gains.
  - The demand for industrial process heat is driven by GDP growth and projected output from the land-sector (i.e. projected dairy and meat output). Assumptions are also made as to the extent of future energy efficiency gains.

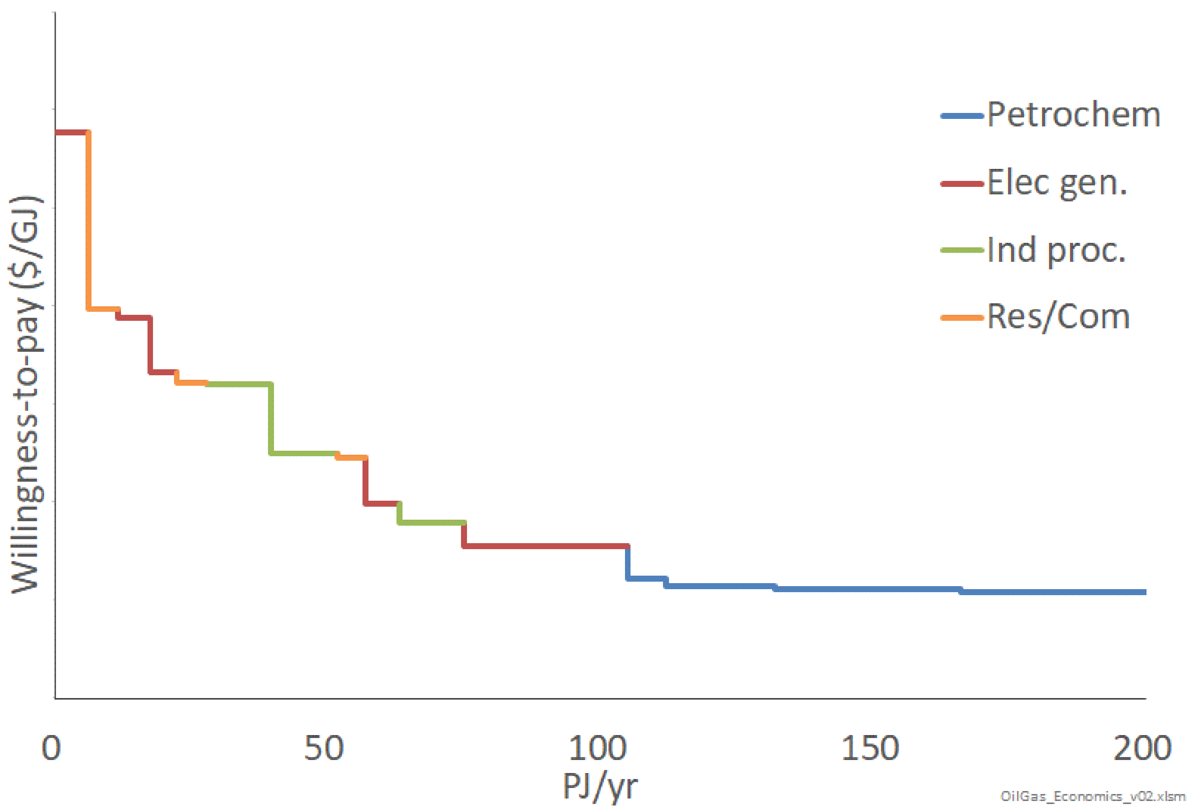
[21] In the early 1990s, gas was also used to make synthetic petrol – 'synfuel'. This was a type of petrochemical process.

– Overall electricity demand – split between generation to meet baseload demand, and generation to provide 'peaking' electricity services (including the role that gas-fired generation plays in balancing variable renewable generation on a seasonal and year-to-year basis). As well as population and GDP-driven growth in current demand segments, we project the uptake of electric vehicles and industrial process heat electrification – both of which are dynamically linked to the model's projection of electricity and gas prices, and the scenario-driven assumptions around carbon price and oil and gas prices.

- In contrast, the potential demand for gas for petrochemical production is represented by the production capacity of the existing methanol and urea production facilities.
- We estimate each segment's willingness-to-pay for gas to meet the projected underlying demand by calculating competitiveness of gas relative to the alternative:
  – In the case of space, water, and process heating, the principal alternatives are switching to electric heating and (in the case of process heat) biomass;
  – In the case of electricity generation, the principal alternative is renewable electricity generation (wind, geothermal, solar and hydro);
  – In the case of petrochemical production, the alternative is overseas production.

  For each of these segments, we calculate the threshold gas price beyond which it would be cost-effective to switch from New Zealand gas to the alternative.
- The above approach effectively builds up a demand-curve for gas, which is stylistically represented in Figure 17.

Figure 17: Stylistic representation of the demand-curve for gas



- The model then simulates the interaction of this demand curve with the effective supply-curve for gas, being the long-term cost of developing gas reserves and resources factored by production capacity limits as described previously in section 2.4. This results in a projection of how much of the demand for the service (e.g. heating, electricity generation, demand for methanol & urea) is met by gas versus the alternatives (e.g. electric heating, renewable generation, overseas production of methanol & urea). Projected gas demand for a year, feeds into how much gas is available to be developed for subsequent years. Different assumptions feeding-in to the supply-side of the equation (e.g. how much gas there is to develop and at what cost) would alter the projections of demand for the different sectors out to 2050.

Appendix 6 sets out some detailed analyses of the dynamics of each demand segment which drive the effective New Zealand demand-curve for gas at any moment in time. This section of the report summarises the key aspects of these analyses.

Although Figure 17 is a stylistic representation, the magnitudes of the annual quantities of gas demanded by each segment (as represented by the x-axis), and the relative values for the ability-to-pay between the segments (as represented by the y-axis), have been set to be broadly consistent with current levels. As such, it is a useful basis on which to draw-out some of the key dynamics of the New Zealand gas demand segments.

The reality of the different segments is that they will not be discrete 'blocks' as shown in this graph, but rather a continuum representing many different gas-using situations (as set out in more detail later in this section). We have simply split the key segments as terciles for this graph, except for:

- electricity generation which has three blocks of peaking generation, a block of cogeneration, and a large block of baseload power generation.
- petrochemicals which are split into the three methanol production trains and the one urea train

Petrochemicals demand has driven much of the New Zealand gas market outcomes to-date

Figure 17 highlights that the segment with the lowest willingness-to-pay is petrochemical production. This willingness-to-pay is set by the opportunity cost of producing petrochemicals overseas. Key aspects of this NZ-vs-overseas-petrochemicals dynamic include: the sunk capital associated with NZ production, the age and relative efficiency of NZ production, and international shipping costs.

The fact that petrochemicals production has the lowest willingness-to-pay of all the gas segments, combined with its very large size, has resulted in two important outcomes:

- As previously described in section 2.1, petrochemical production has scaled-back at times of scarcity (particularly after the Maui re-determination in the early 2000s), and has increased during times of relative supply surplus. As such, it has played a key-role for the upstream industry in terms of helping to monetise gas reserves and in providing confidence that there would be a market for any future resources discovered from exploration / development investment. It has also been important for other downstream segments in terms of reducing consumption at times of scarcity, which enables scarce gas to go to higher value gas uses.
- Methanex's willingness-to-pay has been a key driver of New Zealand wholesale gas prices, given that the upstream supply curve has effectively intersected the demand curve at this point. This willingness-to-pay has varied over time as the dynamics of the world methanol market (and associated methanol prices) have changed.[22]

During the years of extreme supply tightness, post the Maui re-determination and before the new fields such as Pohokura and Kupe had been developed, the scaling back of Methanex meant that prices started increasingly to be set by the next segment of demand along the demand curve. If

[22] Most of Methanex's gas-supply contracts have a risk-sharing arrangement which link the price paid for gas to the world price of methanol.

future situations of supply scarcity emerge, leading to the exit of Methanex, it would be likely that similar dynamics would result in gas prices being progressively set by the next highest segments of the demand curve.

The willingness-to-pay for other segments exhibits significant variation

Figure 17 highlights that the willingness-to-pay for the other segments (space & water heating, process heat, and electricity) exhibits significant variation both between and *within* these different segments.

The fact that the willingness-to-pay for gas varies *by segment* should be no surprise, given the very different characteristics of these segments and the nature of the alternatives to gas for each segment.

The fact that there is significant variation *within a segment* reflects that there are very different circumstances for the different gas-users within each segment, and which affect the relative economics of gas versus the alternative.

For space and water heating, the analysis in section 6.2 of the appendix highlights that the main alternative to gas is electric heating. The economics of the different options are dominated by the capital cost of the appliances, as switching out an existing workable appliance (gas or electric) is very costly. Thus, there is significant variation according to whether an appliance needs replacing, or not. The presence of fixed costs of fuel supply (both network and retail costs) means there is also significant variation in the effective $/kWh cost of the different options according to whether a consumer has a large or small demand for heating.

For process heat, a significant driver of the variation in willingness-to-pay relates to variations in the costs of alternative energy sources. For example, there is significant variation in the cost of biomass, driven by the extent to which existing process heat demands are located near to potential sources of biomass. There can also be material variations in the cost of electricity, driven by the extent to which electrification would require significant network investment. Another source of variation is driven by the age of existing gas-fired boilers and when they might need replacing. Section 6.3 in the appendix sets out this analysis in more detail.

For electricity generation, the biggest source of variation relates to the different duties currently performed by gas-fired generators – i.e. as between 24/7 'baseload' generation, and infrequently-required peaking generation to provide seasonal and dry-year firming. For both options, the key alternative is building renewable generation. However, the capital intensity of renewable generation means it is not very economic for very-infrequent dry-year duties, although it is quite competitive for baseload generation.

This gives rise to the interesting dynamic illustrated in Figure 17 that electricity generation has both the lowest willingness-to-pay (for baseload generation) and the highest willingness-to-pay (for infrequent dry-year-peaking generation) of all the non-petrochemicals demand segments. As such, while there is a very real likelihood of baseload gas-fired generation being displaced by new renewables within the next decade, it is likely that some gas-fired peaking generation will be cost-effective for several decades to come – particularly to perform infrequently-required winter peaking and dry-year duties – even at very high carbon prices.

Section 6.4 in the appendix sets out this analysis in more detail.

An increasing price of carbon will affect the willingness-to-pay, but to differing degrees between demand segments

One of the core planks of New Zealand's greenhouse policies is the Emissions Trading Scheme (ETS), which requires emitters to acquire 'credits' to offset their emissions. Through this process of acquiring and surrendering emissions credits, emitters are exposed to a carbon price.[23]

New Zealand carbon prices are currently capped at $25/tCO_2e. However, it is generally accepted that carbon prices will need to rise if New Zealand is to achieve the reductions required under its emissions reduction targets. Provisional indications are that the review of the ETS will result in the current $25/tCO2e cap being lifted to deliver higher carbon prices.

Various agencies have sought to model or estimate the carbon prices necessary to achieve our domestic emission reduction targets, as well as the broader international prices required to achieve international targets. Some of these estimates are summarised in Table 3 below. Each agency's modelling has its own unique focus and uses a different approach to form its carbon price estimates, resulting in a wide range of results. However, the consensus is for future carbon prices materially higher than what we have today.

Table 3: Future carbon prices for emission reduction targets

International / domestic price	Target	Agency	Carbon price $NZD /tCO₂e[24]				
			2020	2025	2030	2040	2050
International	Paris agreement	Carbon Pricing Leadership Coalition[25]	55 - 110		70 - 135		
	Paris agreement	International Energy Agency[26]		86		192	
Domestic	Paris agreement	Business NZ Energy Council					60 - 115
		Westpac					111 - 147
	Net-zero by 2050	Concept and MOTU for the Productivity Commission					157 - 250
		NZIER					227 - 2,092

The carbon content of natural gas means that a carbon price of approximately $19/tCO_2 increases the effective cost of using natural gas by $1/GJ. The corollary of this is that every $19/tCO_2 increase in the price of carbon generally reduces the willingness-to-pay of a gas-consuming sector by $1/GJ.

[23] Throughout this report, we colloquially refer to the price of emissions credits as 'carbon prices', though we really mean 'carbon dioxide equivalent prices' (t/CO2e), which accounts for the different greenhouse potential of commonly emitted gases.
[24] (0.73 USD/NZD)
[25] https://www.carbonpricingleadership.org/report-of-the-highlevel-commission-on-carbon-prices/
[26] Sustainable Development Scenario from its World Energy Outlook

Thus, \$100/tCO_2-e would add \$5.4/GJ to the effective price of using (and thus willingness-to-pay for) gas. Moving from the current \$25/tCO_2-e price to \$100/tCO_2-e would increase the average residential annual bill by approximately \$125/yr (incl. GST). This would represent a 12% increase in such a bill. In contrast, it would represent approximately a 48% increase in the cost of using gas for a very large industrial consumer.

For reference \$100/tCO_2-e would add approximately 27 c/l (incl. GST) to the price of petrol. Given current carbon prices of \$25/tCO_2-e (which add approximately 7 c/l (incl. GST)), moving to \$100/tCO_2-e would add a further 20 c/l, increasing the current pump price of petrol by approximately 9%.

Under the ETS, some industrial activities which are both emissions-intensive and trade-exposed (EITE) only face a proportion of the carbon price through the Industrial Allocation mechanism. This mechanism is intended to address the fact that EITE sectors face competition from overseas producers who don't currently face a cost of carbon, and thus there is the risk of 'carbon leakage'. That is, there is a risk of New Zealand production closing down due to the cost of carbon, only to be replaced by more carbon-intensive production in an overseas country that hasn't imposed a cost of carbon on its industrial sectors.

The key gas-consuming sector that enjoys some protection from a reduced carbon price is the petrochemical sector. Due to the dynamics set out in Appendix 6.5, methanol production currently only faces approximately 3% of the carbon price, and urea production only 10% of the carbon price.[27]

The effect of a price of carbon on the willingness-to-pay of the different sectors is illustrated in Figure 18 below.

The four different charts represent the willingness-to-pay for gas under four different \$/tCO_2-e carbon price scenarios: \$25, \$75, \$125, and \$175.

For all sectors other than petrochemicals, every \$19/tCO_2-e increase in carbon price reduces the willingness-to-pay by \$1/GJ – i.e. the demand-curve shifts downwards.

However, due to the effect of Industrial Allocation under the ETS, every \$19/tCO_2-e increase in carbon prices reduces methanol's willingness to pay by \$0.03/GJ, and urea's willingness-to-pay by \$0.1/GJ.

As the carbon price increases, the willingness-to-pay of gas-using sectors decreases, but with the reduction for the petrochemical sector being significantly less than for the other sectors. This relative sensitivity means that the petrochemical sector's position on the demand curve moves to the left.

[27] Methanol and Urea are both in the most emissions-intensive category of sectors classed as Emissions Intensive Trade Exposed (EITE) industries and thus qualify for 90% free allocation of units. This allocation reduces the effective carbon price to these industries to 10% of the market price. However, virtually all methanol produced in New Zealand is exported overseas and so the approximately 2/3 of carbon that is embodied within the methanol (as opposed to the 1/3 emitted associated with its production) is excluded from the ETS – further reducing the effective carbon price that Methanex faces. In contrast, all the urea that is produced in New Zealand is consumed in New Zealand, and thus the carbon embodied within the urea is included within the ETS.

Figure 18: Illustration of the variation in willingness-to-pay due to increasing carbon prices

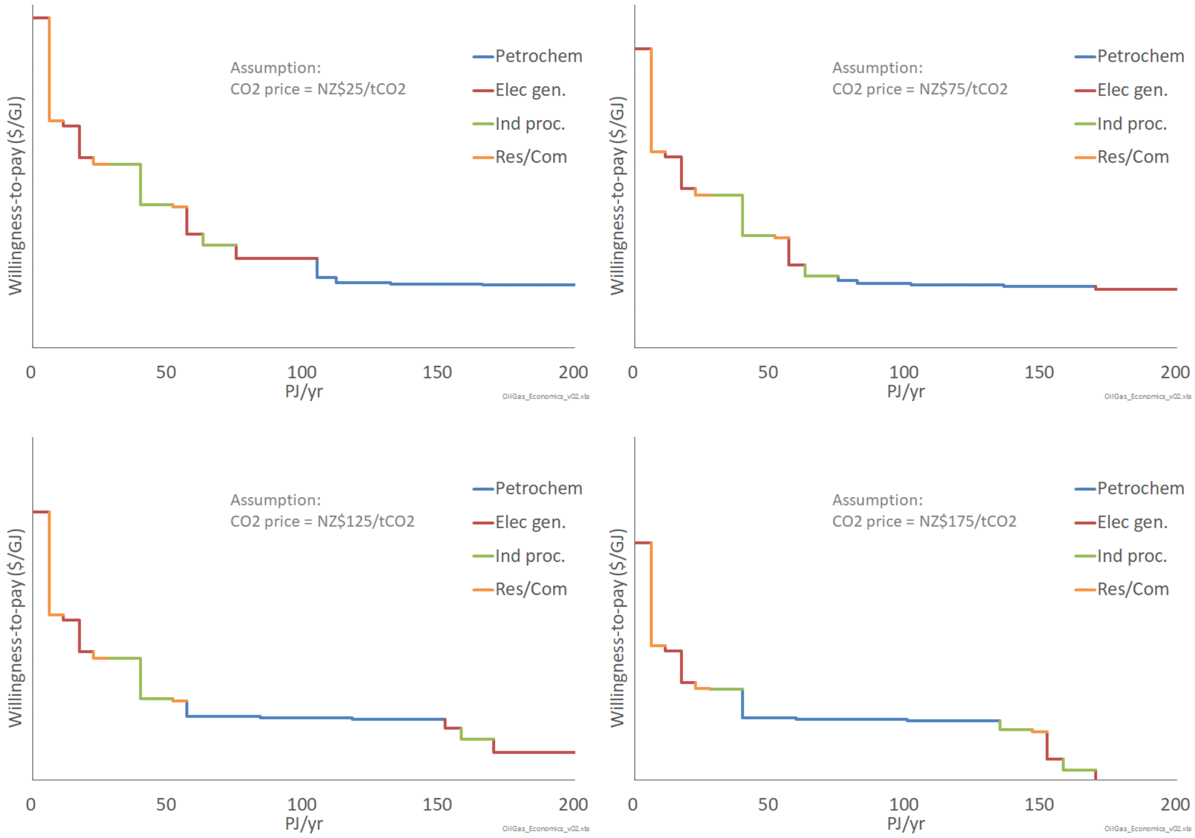


Figure 18 also illustrates how that as the carbon price increases, the willingness-to-pay for some consumers in some segments will fall below the market price of gas, resulting in such consumers switching to an alternative. (Or in the case of gas-fired power generation, for such generation to be retired, to be replaced by renewables).

In addition to the effect of Industrial Allocation, there are some other factors which mean that the willingness-to-pay will not obey the simple \$19/tCO_2 = \$1/GJ dynamic.

One factor is that electricity generation itself results in some carbon emissions, and thus a price of carbon will increase the price of electricity alternatives such as heat pump heating or electro-boilers for process heat. This means that the willingness-to-pay for gas won't fall by as much for gas uses where the alternative is an electricity option (i.e. electric space, water or process heating).

However, for the reasons set out in Appendix 6.2.2, this effect is not uniform and varies significantly (and in a complex way) according to:

- The within-year and within-day profile of consumer demand, with baseload electricity demand (e.g. to supply industrial process heat) largely being met by renewable generation, whereas peaking demand (particularly winter-focussed demand such as residential and commercial space heating) is largely met by fossil generation. This means that the willingness-to-pay for gas will largely fall for industrial process heat by the \$19/tCO_2= \$1/GJ level set out above, but much less for a use such as space heating where the price of the electricity alternative will also rise as carbon prices rise.
- The extent to which the introduction of a carbon price in the electricity sector will result in the development of renewable generators to displace existing fossil generators (and also make geothermal carbon capture and storage (CCS) economic beyond a certain point.) The effect of

this would be to make the rate of increase in electricity prices with carbon prices, decline with increasing carbon prices, with this rate of decline varying between different demand profile shapes.

It is potentially the case that non-price factors could be significant in consumer fuel choice decisions. This is particularly for mass-market demand with two possible countervailing forces:

- The quality aspects of gas heating may be a significant aspect of the price/value equation for consumers. For example, never running out of hot water with an instant gas water heater is understood to be a major value benefit for consumers compared with electric cylinder (including heat pump cylinder) options. This is illustrated by the significant uptake of LPG instant gas water heating over the last decades to displace existing hot water cylinders, even though from a $/kWh of hot water perspective, sticking with the hot water cylinder would have been cheaper.

  Similarly, the controllability and speed of heating from gas central heating relative to heat pumps is part of gas' value proposition. Conversely, the fact that heat pumps can be used as air conditioners is a countervailing value proposition for heat pumps in parts of New Zealand with hot summers.

- Public perceptions about global warming may drive consumer behaviour to switch away from gas to electric heat pumps, even though the strict economics given underlying carbon prices at the time may not justify such a move.

4 Projections of supply and demand

This section describes our overall gas market projections out to 2050, based on our modelling of the economics of the interactions between supply and demand.

4.1 Modelling methodology

The model projects the extent of development of gas resources based on the fundamental logic that investment in the development and production of gas resources in a given year is only undertaken if the cost of development is less than the willingness-to-pay by the demand-side for that gas.

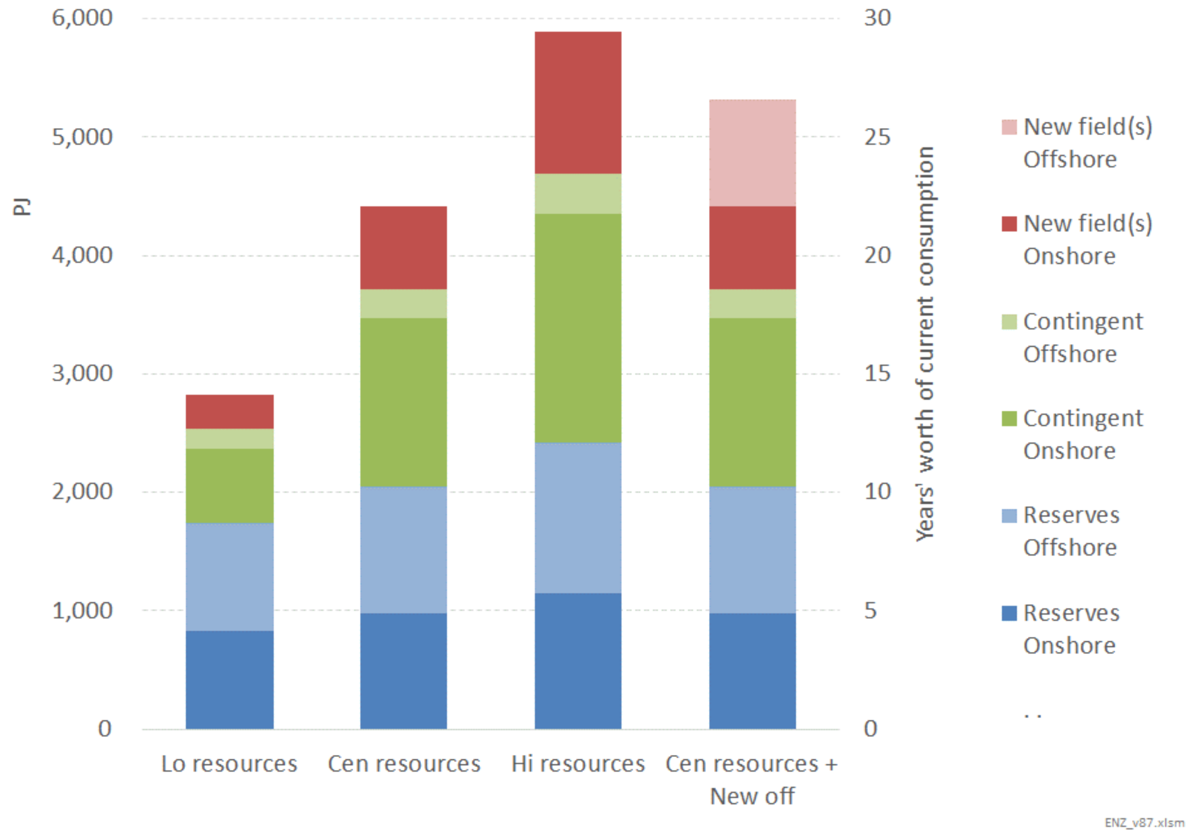
As set out in section 3, this demand-side willingness-to-pay is set by the cost of alternatives to using gas – being the cost of overseas production for the petrochemicals sector, and the cost of fuel switching for all other demand segments. For all demand segments, this willingness-to-pay is factored by the carbon price – taking into account the effect of any industrial allocation under the ETS in the case of petrochemicals production.

As New Zealand's gas reserves and resources become depleted, another alternative starts to drive modelled pricing outcomes – being the future cost of importing LNG if New Zealand continues consuming gas to the point where it will eventually have insufficient gas supply to meet demand. As the time when New Zealand would have to import LNG gets closer, the time-discounted effect of future LNG import prices on gas prices in a given year starts to rise. This results in a 'price rationing' effect – that is, some demand will switch to their non-NZ-gas alternative if the price of gas rises above their willingness-to-pay. This price rationing preserves a greater amount of remaining NZ gas resources for higher-value gas users, and postpones the time when LNG imports would be required.

Several scenarios were run which varied two key sensitivity parameters:

The first scenario sensitivity is the amount of gas reserves and resources that could be developed to meet any demand whose modelled willingness-to-pay is greater than the cost of developing such gas. The scenarios for the scale of potential additional gas that could be developed was set out in section 2.3 previously and is shown again in Figure 19 below.

Figure 19: Scenarios for scale of additional reserves and resources available for development as at 1 Jan 2019



The second scenario sensitivity is carbon prices. A range of different carbon prices have been examined as set out in Figure 20 below.

These carbon price scenarios were chosen to explore the sensitivity of outcomes to carbon prices, rather than being predictions of where carbon prices are likely to go. In particular, the 'Cur CO_2' scenario was chosen to represent a counterfactual, being a continuation of current CO_2 prices.

That said, the levels were informed by the levels indicated in various international and New Zealand modelling exercises as being required to meet the Paris Agreement and New Zealand's net-zero-by-2050 targets. (As set out previously on page 34, and illustrated in the graph).

Figure 20: carbon price scenarios

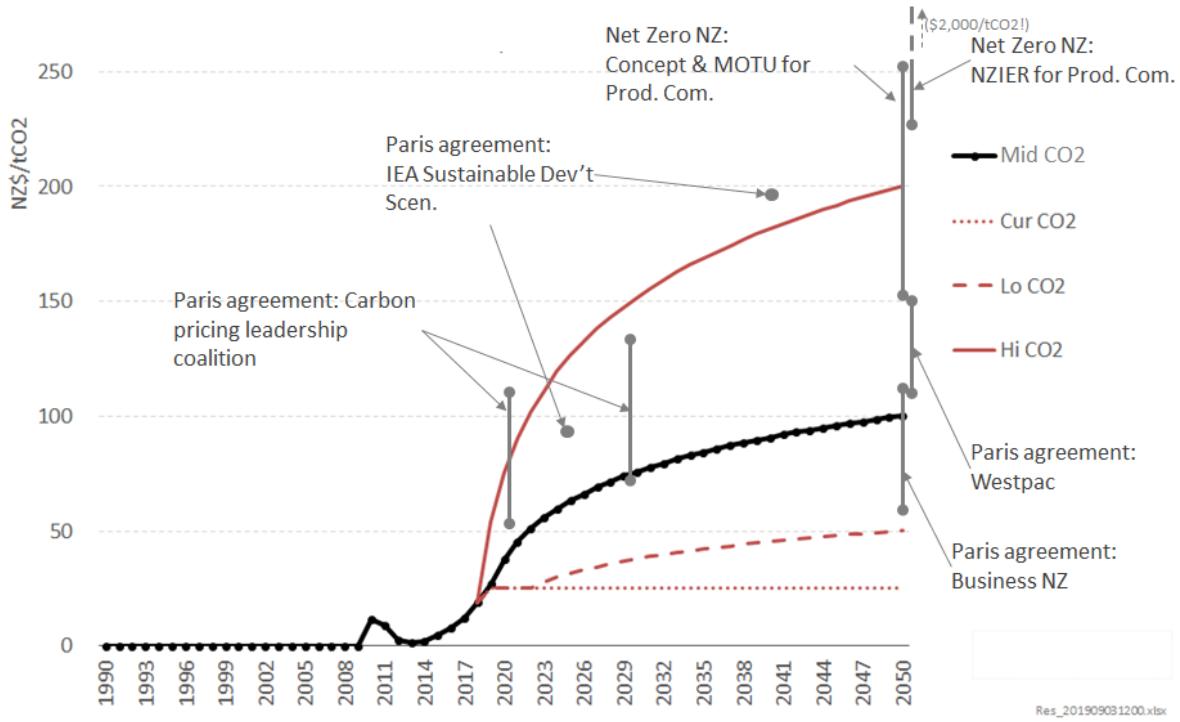


Table 4 sets out how these scenarios around future gas resources and carbon price have been combined into 'composite' scenarios.

Table 4: Composite market scenarios

Composite scenario	Carbon price scenario	Resources scenario
Reference	Mid	Central
Cur CO_2	Cur CO2	Central
Lo CO_2	Low	Central
Hi CO_2	High	Central
Lo Resources	Mid	Low
Hi Resources	Mid	High
New Offshore	Mid	Cen res + New offshore

4.2 Modelled results

4.2.1 Reference scenario

Figure 21 on the next page presents the projections of supply and demand for the Reference scenario.

It indicates that:

- Petrochemical production will continue at current levels until the middle of the next decade when one of the Methanol production trains will exit, followed by a second train six years later, and the third eight years after that, just before 2040.

This exiting of petrochemical plant is driven by a combination of

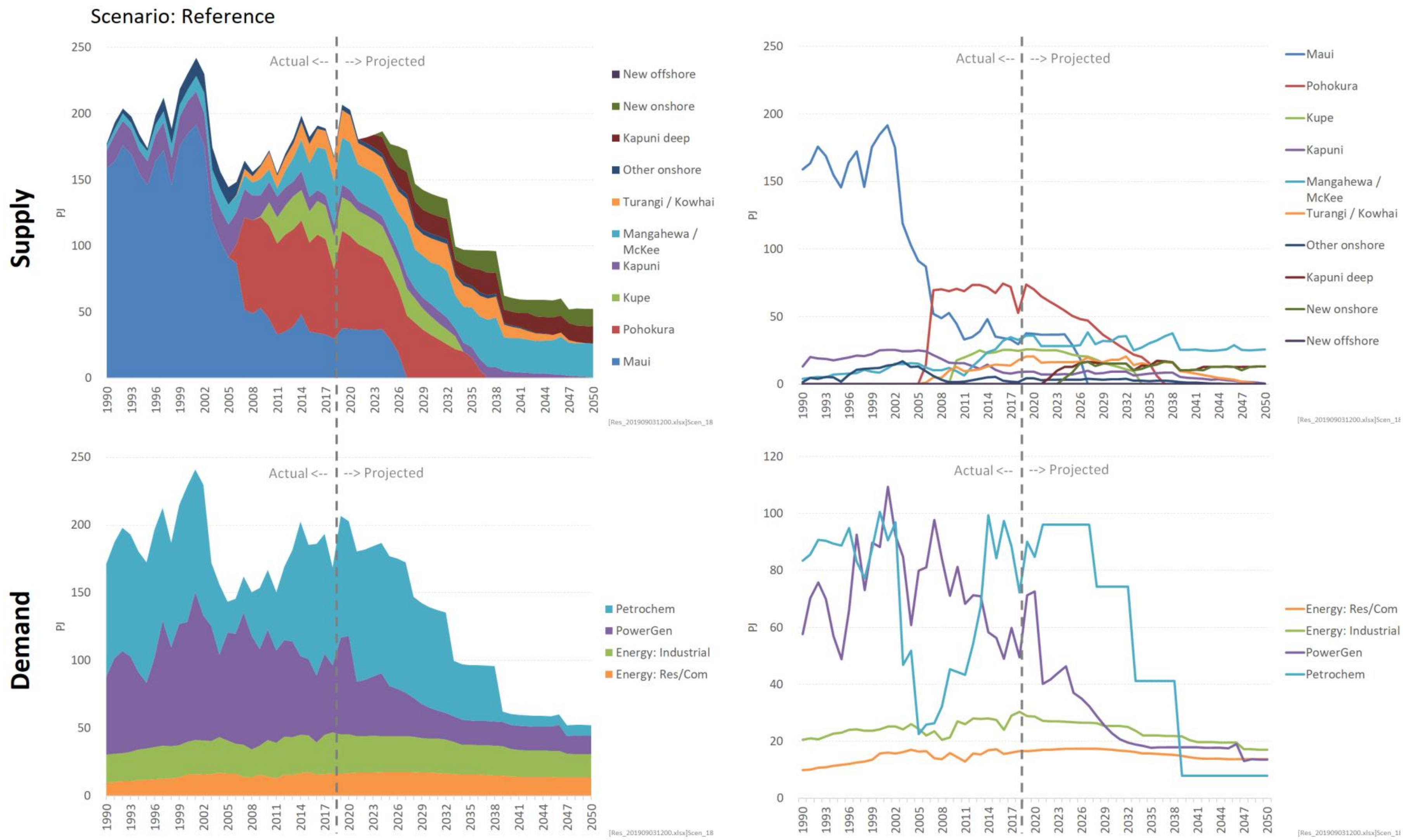
- loss of upstream deliverability as major gas fields retire (with the three remaining offshore fields (Pohokura, Maui and Kupe) progressively coming to the end of their lives at around the time the first two methanol trains retire); and
- a price rationing dynamic in terms of preserving remaining reserves and resources for higher value gas users rather than bring forward the time when New Zealand gas resources are insufficient to meet demand and importing much-higher-priced LNG would then be required.

The Ballance urea plant is projected to outlast Methanex's methanol plant due to a combination of New Zealand urea's relative import versus export parity pricing advantage compared to methanol, and its much smaller size (on a TJ/day basis) – noting that loss of deliverability of a scale sufficient to support methanol production is an important driver of Methanex's progressive exit.

- Gas-fired power generation sees a short-lived initial increase as growth in electricity demand is met by increasing the utilisation of the Taranaki Combined Cycle (TCC) station. However, within a couple of years TCC is scaled back due to the development of new wind and geothermal stations, and by 2023 TCC is projected to retire from baseload operations, followed by the e3p station a couple of years later. This retirement of baseload gas-fired power generation is driven by rising carbon prices and falling renewable generation costs, resulting in new renewable plant becoming cheaper in running costs than existing baseload gas-fired plant. This exiting of baseload gas-fired generation results in New Zealand's percentage of generation from renewables rising to 90%. This percentage then rises to 95% by 2033 and creeps further up to almost 98% as the fall in the relative cost of renewables results in progressively more 'over-build' of renewables to displace the remaining gas-fired peakers (and coal-fired Rankines) from some peaking roles. However, a rump of gas-fired peaking generation remains to perform low capacity-factor duties such as seasonal and dry-year peaking.[28] These results are consistent with those produced by the Interim Climate Change Commission for its modelling of the economics of moving to higher percentages of renewable generation.
- Industrial process heat exhibits a gradual decline over the projection period, as higher carbon prices start to make it cost-effective for some existing gas-fired process plant to switch to low carbon alternatives such as biomass or electricity. However, over half of industrial process heat demand is projected to remain by 2050.
- A similar dynamic of gradual carbon-price-driven decline is projected for mass-market space and water heating.

[28] In this Reference scenario, the model projects that carbon prices reach a level where it would be economic to retire the Huntly Ranking coal units just before 2040. This results in a slight up-tick in gas demand for peaking units to replace the duties that the coal-fired units were performing to that point.

Figure 21: Reference scenario projections of supply and demand



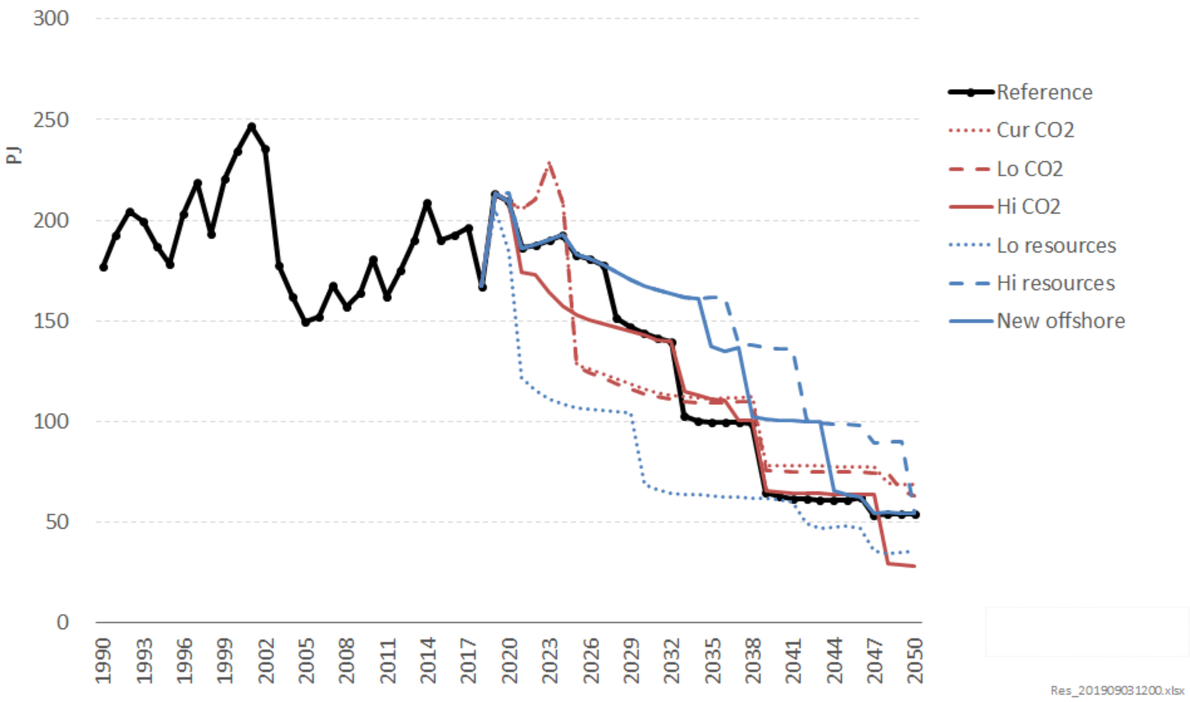
4.2.2 Sensitivity to scenario drivers

Figure 30 at the end of this section presents the detailed supply / demand graphical projections for all seven composite scenarios. The discussion below draws together the insights from these different scenario runs.

Overall gas demand

Figure 22 shows the summary projections of total gas demand. It shows a general pattern of gas demand reduction over the period to 2050, but with variation as to the timing of when such reduction occurs.

Figure 22: Summary projections of total gas demand



It indicates that the most significant driver of projected overall gas demand is total resource availability, rather than carbon price – with the Lo Resources scenario projecting much lower gas consumption than other scenarios, and conversely the Hi Resources and New Offshore scenarios projecting much higher levels of gas demand.

There is much less variation in the overall quantity of gas demanded between the carbon price scenarios, although there is some variation between these scenarios as to the timing of gas demand. For example, the Hi CO_2 scenario projects lower gas demand than the Reference scenario at the start of the projection period, but slightly higher gas demand for some of the years at the end of this projection period.

Further analysis of the results indicates that these outcomes are due to the resource availability and carbon price drivers having differing degrees of impact on the different demand segments, and with these different impacts having inter-linked outcomes.

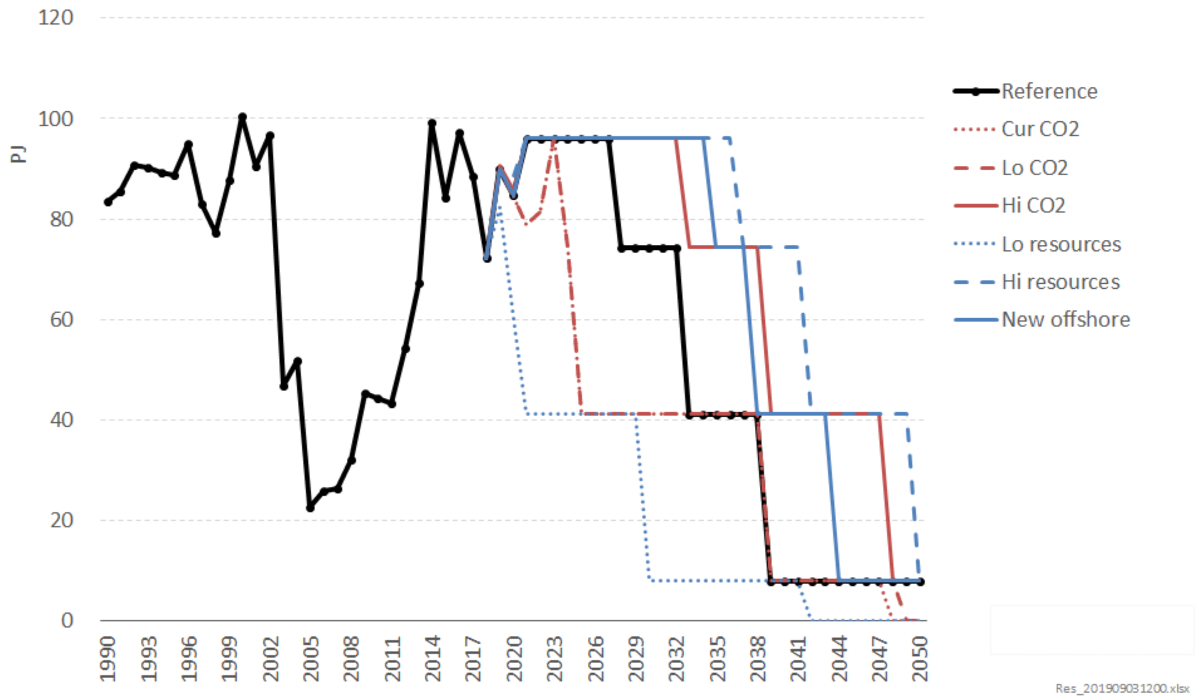
Petrochemical demand

Figure 23 below illustrates that the segment of demand most affected by the quantity of gas reserves and resources available to be developed is the petrochemical sector. The modelling suggests that petrochemicals production will continue until a point is reached where it becomes economic to exit due to a combination of loss of upstream deliverability as major fields exit, coupled with a price rationing dynamic in terms of preserving remaining reserves and resources for higher value gas users rather than bring forward the time when New Zealand gas resources are insufficient to meet demand and importing much-higher-priced LNG would then be required.[29]

This exiting of petrochemical demand tends to occur progressively on a train-by-train basis, with the three methanol production trains exiting first, followed by the Ballance urea train.

[29] If the physical deliverability limits are removed from the model, the model projects that onshore gas production increases as the offshore fields retire. This is because the model is projecting it is more economic to bring forward gas (and associated oil) production. However, this may be unrealistic for the onshore gas reserves & resources scenarios considered, as such increased production levels only occurs for 5 to 10 years before price rationing of remaining resources starts to make it more cost-effective to scale-back petrochemical production. Analysis of the cost of developing gas suggests that if a processing facility were only to be used for such a relatively short space of time, the increase in the cost of producing gas could push the cost of gas supply above the petrochemicals sector's willingness-to-pay. If there were considerably greater onshore resources that could be developed, a processing facility would have a longer useful lifetime, and it is likely that the depletion of the existing offshore fields would result in significant investment in production and processing capability in onshore fields.
If existing processing facilities for the offshore Maui, Pohokura or Kupe fields could be redeployed to process onshore fields once the offshore fields have retired, this cost-benefit equation changes somewhat. However, initial sensitivity testing of this prospect (whereby deliverability from the Mangahewa and Kapuni fields was doubled after the retirement of the remaining offshore fields) suggests that increased processing capacity may only materially affect outcomes for the Hi Resources scenario: Petrochemical production continues at higher levels for longer, but other gas users' demand is not significantly affected as there is sufficient gas to support higher petrochemical demand and meet other users' demand out to 2050. For the other scenarios, the price rationing dynamic overcomes the production capacity dynamic such that the model doesn't significantly increase Mangahewa and Kapuni output once the offshore fields retire, and the projections of demand don't significantly change compared to scenarios where Mangahewa and Kapuni deliverability remains the same.
Futures with relatively high oil prices could further change this trade-off between early production and price rationing, as the value of rationing gas for higher-value uses will be counteracted by the value of producing gas earlier and realising the oil sales. That said, re-injection of gas back down into the field after the oil has been stripped could enable early oil sales *and* rationing of gas for higher-value users. The economics of re-injection are relatively field specific and haven't been considered in this modelling.

Figure 23: Summary projections of petrochemical demand



The scaling back occurs on a train-by-train basis due to a combination of the progressive price rationing, and the upstream deliverability limits as the offshore fields retire, with the timing of how quickly the trains scale back driven by the specifics of the scenario.

The order of train retirement is based on assumptions regarding their efficiency (as set out in section 6.5 in the Appendix). Thus, the less-efficient Waitara Valley methanol train is taken off first, followed by one then the other of the two Motunui trains, and lastly the Ballance urea production train.

The dynamic of production deliverability limits affecting petrochemical demand means that the retirement of the first two petrochemical trains occurs later in the New Offshore scenario, even though the Hi Resources scenario has more gas available overall. This is because the scale of the new offshore field is such that it would support / require a large production deliverability capability. Only in the very end of the projection does petrochemical production in the Hi Resources scenario 'overtake' the New Offshore scenario.

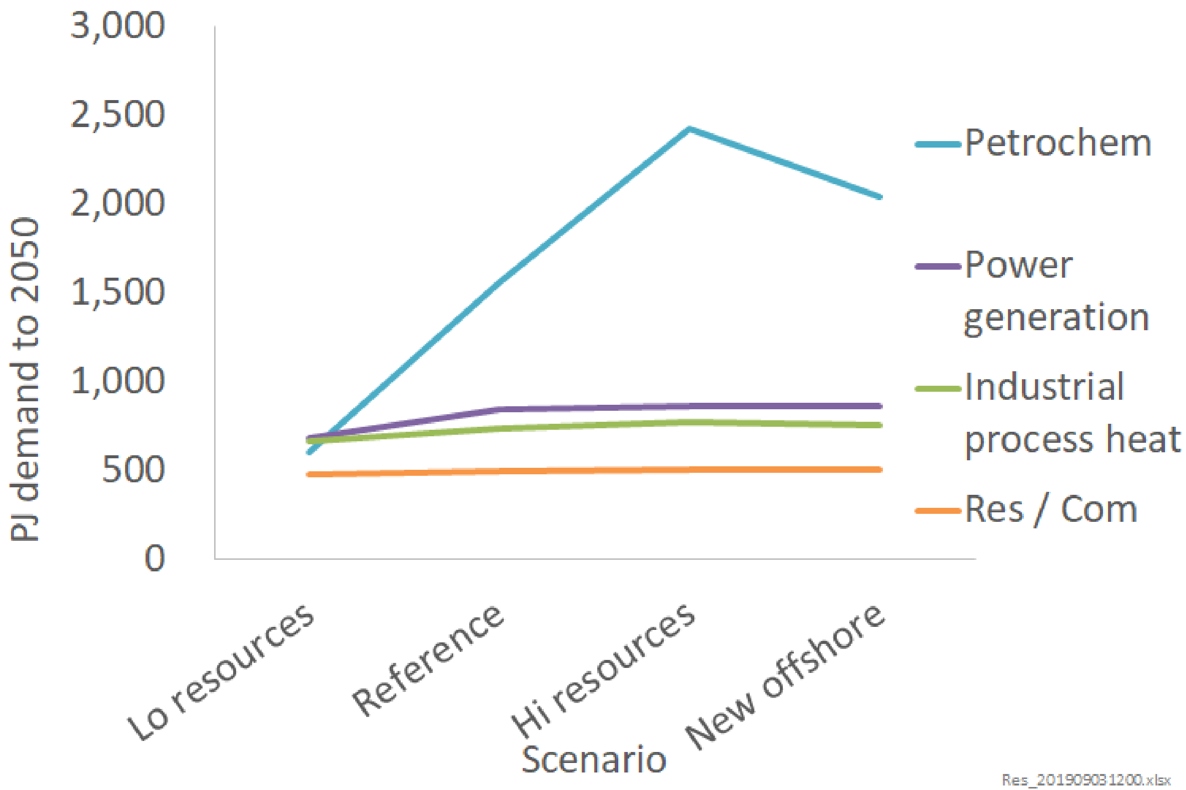
This dynamic of petrochemical production continuing until remaining gas resources are depleted to the point where it becomes economic to price ration gas, also suggests that it would be uneconomic to develop any significant new sources of demand which use gas as a feedstock. This is because existing petrochemical producers have sunk capital, suggesting that their ability-to-pay for gas will be materially higher than a major new gas-as-feedstock demand source. Even if there were material differences in the emissions associated with the hypothetical new versus existing gas-as-feedstock consumers, the threshold carbon price would need to be extremely high for the new plant be able to 'out-bid' existing plant due to the protection such existing plant receives under the Industrial Allocation mechanism of the ETS. Even if Industrial Allocation were removed from the ETS, high-level calculations suggest that the carbon price would need to rise to high levels in order for a hypothetical new low-carbon gas-as-feedstock consumer to outbid existing gas-as-feedstock uses such as methanol production.[30] Further, such carbon price and ETS outcomes would need to happen

[30] An initial back-of-the-envelope calculation suggests the threshold carbon price could be of the order of NZ$150/t$CO_2$e, and potentially higher than $250/t$CO_2$e if the limited remaining gas reserves requires the new petrochemical facility to seek to recover its initial capital cost over a shorter period of time.

very quickly – i.e. before the remaining offshore gas resources are consumed by existing petrochemical production.

As set out further below, other demand segments are affected to a much lesser extent by the scenarios around total gas resource availability, with only the industrial process heat segment being affected by the assumptions around resource availability – but to a lesser extent than petrochemical demand. This is illustrated in Figure 24 below.

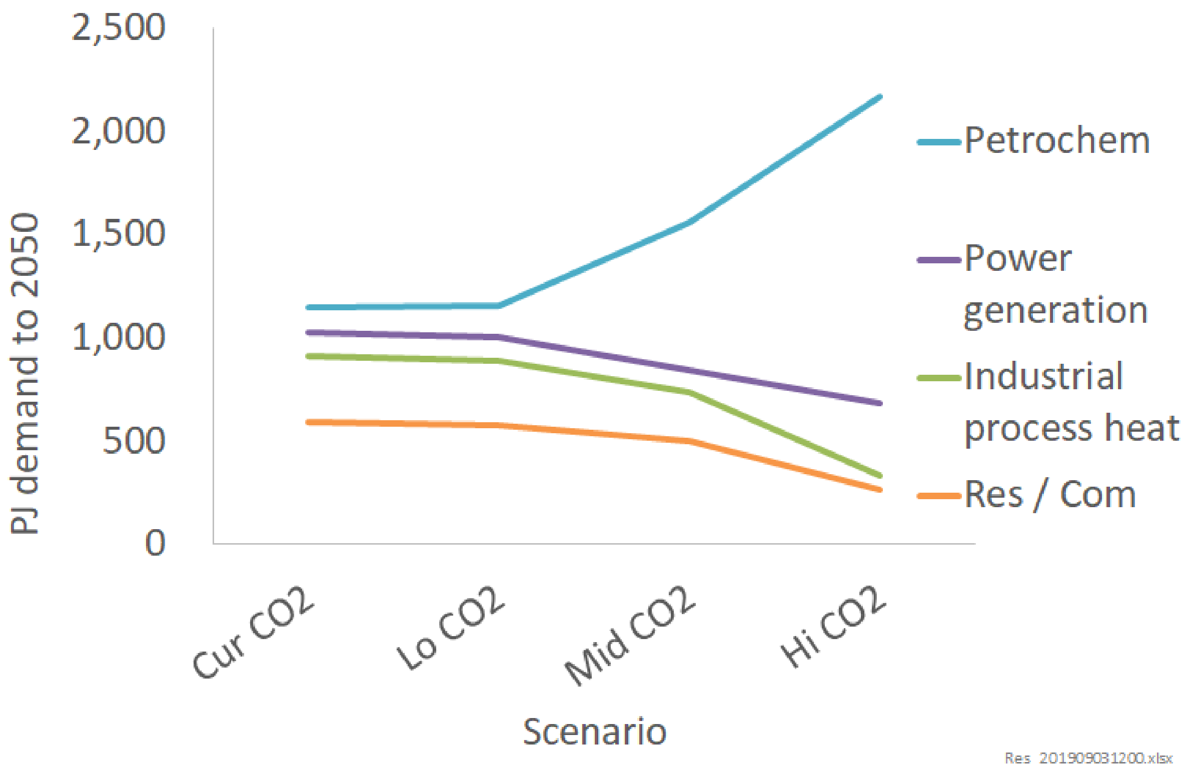
Figure 24: Resource-availability-scenario-driven variation in total demand to 2050 by sector



Thus, within the timeframe modelled (out to 2050), the scenario results indicate that the effect of the altered exploration policy limiting additional offshore exploration will have principally affected petrochemical production in New Zealand. The impact of the altered exploration policy on other sectors will only start to become material beyond 2050. However, as set out further below, these other demand segments are affected much more by carbon prices such that, in a future with high carbon prices, the effect of reduced offshore exploration on long-term gas availability will be moot for these sectors.

In terms of the petrochemical sector's sensitivity to carbon prices, Figure 23 illustrates that petrochemical demand is *positively* correlated with carbon prices. This is even more clearly illustrated in Figure 25 below.

Figure 25: Carbon-price-scenario-driven variation in total demand to 2050 by sector



Thus, significantly greater petrochemical production occurs in scenarios of high carbon price than in scenarios of low carbon price. This is due to a reduction in gas demand by non-petrochemical sectors in high carbon price scenarios, thereby making more gas available for petrochemical production which doesn't face the same carbon price due to the Industrial Allocation mechanism.

If the Industrial Allocation mechanism is removed *and* world methanol producers do not face a cost of carbon, then New Zealand petrochemical production would almost certainly exit in futures of high New Zealand carbon prices. This lost New Zealand production would be replaced by overseas production – most likely a mix of gas and coal-based methanol production, likely leading to higher global carbon emissions.

However, if the rest of the world imposes an equivalent carbon cost on methanol production to that faced by New Zealand production, New Zealand petrochemical production would likely follow the pattern of production shown in Figure 23 for the different scenarios of gas resource availability and carbon price. This is because the sunk capital cost and gas-based nature of New Zealand's methanol production means it is likely to be a relatively carbon-cost-effective source of supply to meet the world's demand for methanol. It was beyond the scope of this study to examine the extent to which world demand for methanol (which is principally used as a feedstock for making various industrial chemicals) would reduce as world carbon prices increase, and the point at which such world demand reduction would result in a reduction in New Zealand production relative to other international sources of production.

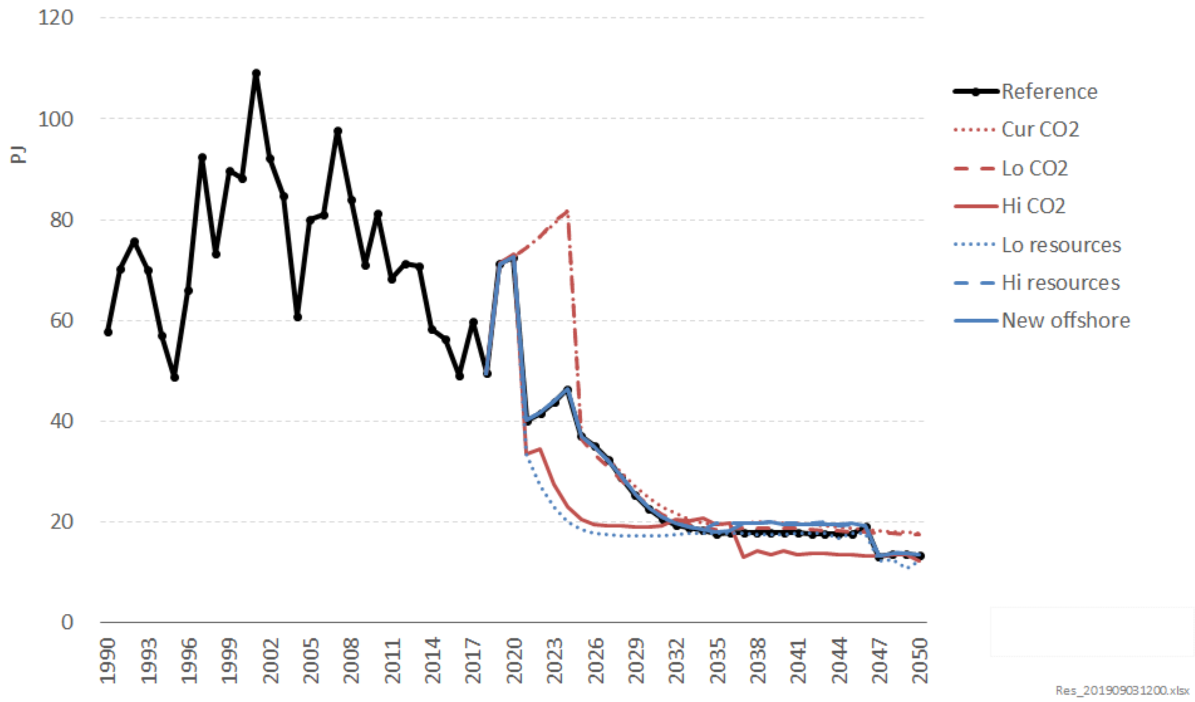
It was also beyond the scope of this study to examine in detail the point at which carbon price divergence between the price faced by New Zealand methanol producers and those in the rest of the world would result in the displacement of New Zealand production by overseas production.

Any early exit of methanol production due to removal of Industrial Allocation would also make a New Offshore scenario much less likely, as it is less likely there would be the scale of demand to support development of a new offshore field at an efficient scale. Likewise, the development of the onshore resources would be spread over a much longer period of time.

Gas-fired power generation

Figure 26 below illustrates that the most carbon-price-sensitive demand segment is *baseload* gas-fired power generation.

Figure 26: Summary projections of gas-fired power generation demand



In the Hi CO_2 scenario where high carbon prices are introduced rapidly, the cost of baseload gas-fired generation soon rises above the point where it becomes economic to build a wind farm to displace existing baseload gas-fired power generation, whereas in the Lo CO_2 scenario baseload gas-fired generation continues for longer. However, even in this Low CO_2 scenario, continued reductions in the price of wind result in this displacement occurring by the middle of the next decade. This is driven by the willingness-to-pay for baseload gas-fired generation falling below that of petrochemical production, resulting in baseload gas-fired generation responding to the price rationing dynamic sooner than petrochemical demand.

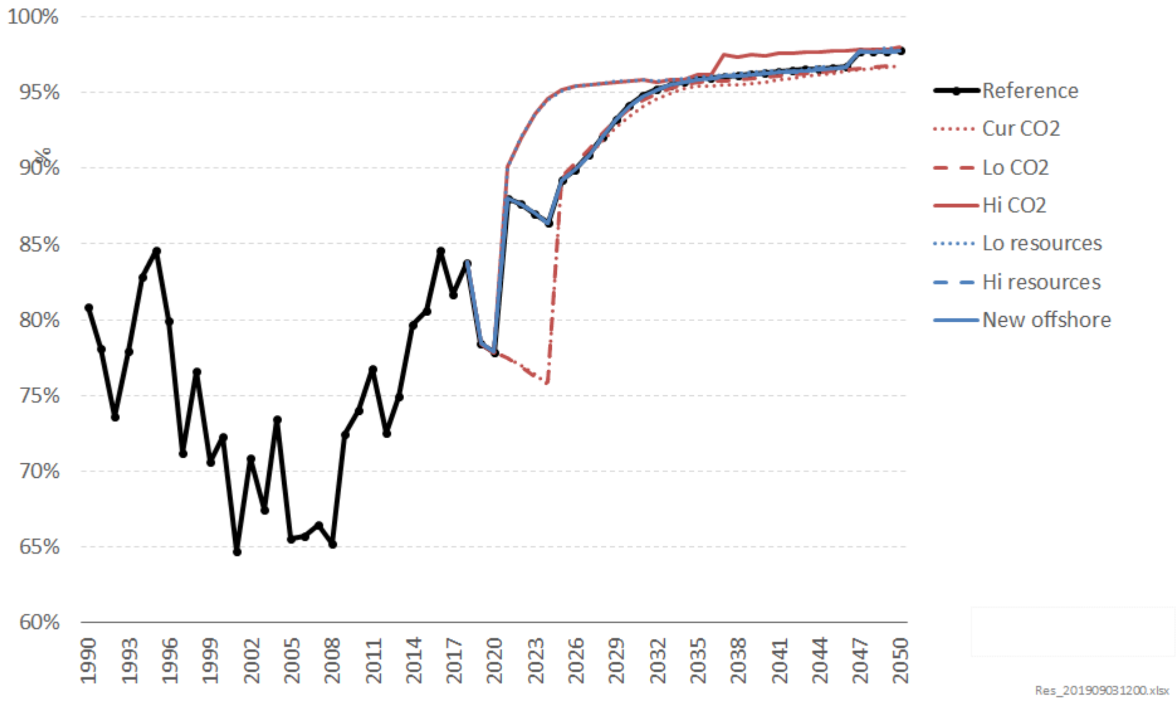
This dynamic of displacement of baseload gas fired generation by wind by the middle of the next decade occurs even for the Cur CO_2 scenario.

Other sensitivity analysis (not shown here) suggests that only a complete removal of carbon price would result in baseload gas-fired generation continuing for a much-longer period. Although even then, it is likely it would eventually exit in the 2040s driven by a combination of: the falling price of renewables; rising maintenance costs of aging gas-fired generation; and a price rationing effect as remaining reserves and resources continue to fall.

Ironically, while *baseload* gas-fired generation is projected to be the most carbon-price-sensitive demand segment, the modelling also suggests that *peaking* gas-fired generation is likely to be the most resilient to carbon prices. This is because the alternatives to peaking gas-fired generation are very costly (as set out in the appendix section 6.4.2).

Figure 27 illustrates that the timing of when the remaining baseload gas-fired generation exits is the biggest driver of when the percentage of renewable generation rises to approximately 95%. It further illustrates that, even in the Hi CO_2 scenario, the percentage of generation from renewables only just comes close to 98%. This is because of the dynamic highlighted above, that the alternatives to peaking gas-fired generation are very costly in terms of cost per unit generated, since they provide infrequently-required seasonal and dry year peaking. A rump of peaking gas-fired generation is required to balance variable renewable generation (particularly hydro). This keeps electricity costs lower and supports greater whole-of-economy decarbonisation through electrification – particularly for transport and process heat. These quantitative and qualitative results are consistent with the Interim Climate Change Commission's report on moving towards higher proportions of renewables.

Figure 27: Percentage of New Zealand's generation from renewable sources



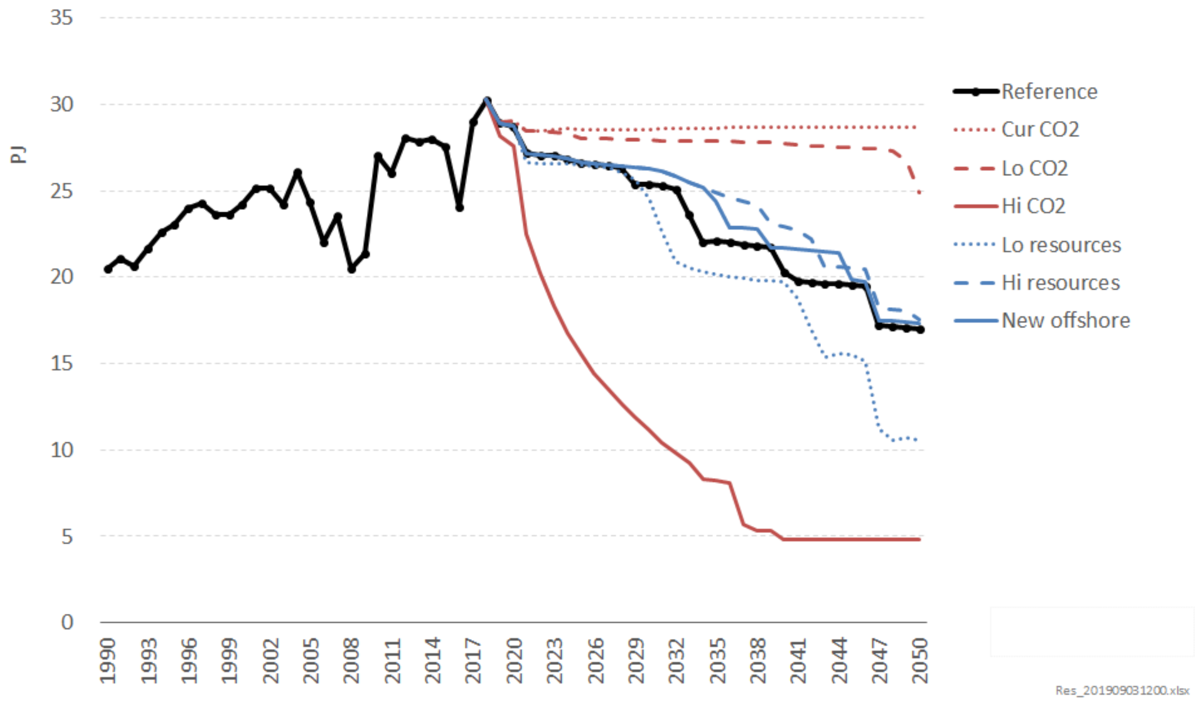
Although it is hard to discern in the charts, our modelling indicates that the Huntly Rankine station operating on coal is likely to remain cost-effective for another decade or so for delivery of the small amount infrequently required dry-year winter generation. This is because of the materially lower non-carbon costs of providing infrequently-required coal versus providing infrequently-required gas.

The exception is in the Hi CO_2 scenario, where are modelling indicates it is more cost-effective for these duties to be met by peaking gas-fired generation, with the Rankine station retired in 2022. While this causes some slight initial increase in the demand for gas, overall this is more than offset relative to the Reference scenario with the general significant reduction in demand for fossil peaking generation in the Hi CO_2 scenario.

Industrial process heat

After baseload power generation, Figure 28 below indicates that the next most CO_2-price sensitive segment of demand is industrial process heat.

Figure 28: Summary projections of industrial process heat gas demand



Unlike baseload power generation, whose sensitivity to carbon prices is relatively 'binary', the analysis suggests that there will be a range of carbon prices where it starts to become economic for different industrial process heat users to switch-away from gas to biomass and electricity, but that this range only 'kicks-in' above a threshold carbon price – approximately \$80/tCO_2. Once this threshold is breached, the reduction in gas-fired process heat demand with rising carbon price is projected to be relatively rapid across a range of carbon prices whose span is of the order of \$100/tCO_2. (This analysis is contained in appendix section 6.3.)

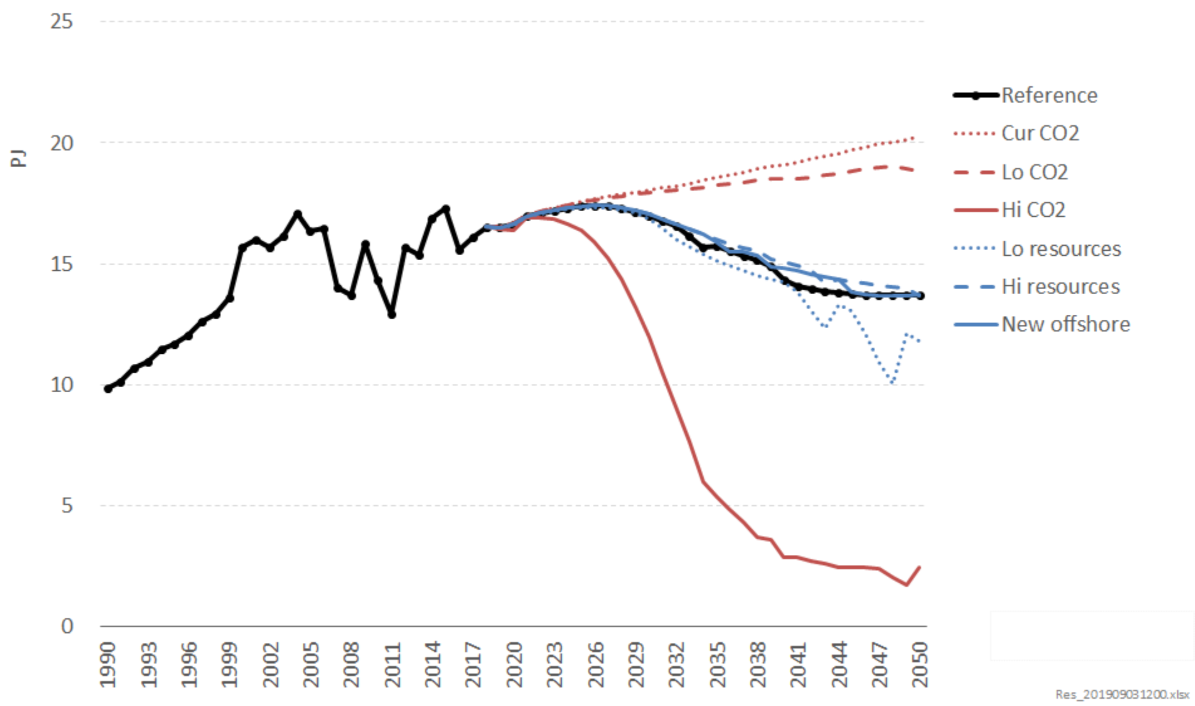
Gas-fired process heat demand is projected to be less sensitive than either petrochemicals or thermal generation to the scale of reserves and resources. This is due to petrochemicals and baseload gas-fired power generation acting as the principal segments which undertake price rationing in response to reduced gas resources. This has the effect of preserving gas for higher value users such as process heat and residential & commercial space/water heating.

That said, towards the tail-end of the projection period, the sensitivity of process heat demand to resource availability starts to become more significant – as by this point, petrochemical and baseload power generation demand will already have exited.

Residential and commercial gas demand

The dynamics described above for process heat are projected to be similar for residential and commercial space and water heating – as illustrated in Figure 29 below.

Figure 29: Summary projections of residential plus commercial gas demand



However, unlike process heat, the model is projecting that a very low carbon price future would see a continuation of the growth in demand for residential and commercial gas – driven principally by population growth. It is also projecting that residential and commercial demand is less sensitive to variations in total resource availability – reflecting the fact that this group is less sensitive to variations in gas wholesale prices than process heat.

Broader implications for consumer prices

In terms of wholesale gas pricing outcomes, as long as petrochemical production continues to operate within New Zealand, medium to long-term wholesale gas prices are likely to be similar to those experienced up until early 2018 – i.e. driven by Methanex's willingness-to-pay.

As discussed in section 5 later, the recent situation of high gas prices is related to a short-term issue of electricity generation capacity shortfall and gas deliverability shortfall, rather than any structural change in the gas market. These deliverability issues are likely to be addressed over the next couple of years by investment in both renewable generation capacity and upstream deliverability.

After petrochemical plant has exited from New Zealand, wholesale gas prices will be driven by the willingness-to-pay of the marginal (in a long-run economic sense) source of demand. This is industrial process heat demand (noting that baseload power generation will already have exited). Although industrial process heat demand has a much higher current willingness-to-pay than petrochemical demand, this willingness-to-pay for gas will fall with rising carbon prices – with the rate of reduction being $1/GJ for every $19/tCO$_2$e increase in carbon prices.

The effect of this, and the progressive rationing effect from progressive demand defection from industrial process heat, is to significantly limit increases in wholesale gas prices. Accordingly, the greatest long-term price uncertainty facing the likes of industrial gas consumers relates to carbon price, not gas price. If carbon price remains at current levels it would not be cost-effective to switch to low-carbon alternatives. However, our whole-of-economy modelling indicates that this would mean New Zealand would not meet its net-zero-by-2050 target.

If carbon prices rise to the level which our modelling indicates is necessary to meet this net-zero target (and which are also consistent with other international studies of the international prices required to meet the Paris Agreement targets), then it would be economic for most industrial process heat gas consumers to switch to biomass or electrification.

A similar dynamic applies to residential and commercial gas consumers – albeit with some complex factors which make projection of outcomes more difficult:

- In general, the carbon price required for it to be economic to switch away from gas for residential & commercial consumers is much higher than for industrial consumers. However, if the retirement of carbon-price-sensitive industrial consumers[31] results in gas pipeline owners seeking to recover this 'lost' revenue by increasing prices to residential and commercial consumers, this could magnify the effective carbon price to residential and commercial consumers. That said, our modelling indicates that there are limits to the extent to which pipeline owners will be able to do this, as this can lead to a rapid 'death-spiral' effect.
- Further, non-price factors are significantly greater drivers of mass-market consumer decisions. It is likely that a future with greater climate change sensitivity will see many consumers increasingly basing their fuel choices on environmental factors as well as economic factors.

Flexibility

While baseload gas prices are only projected to increase modestly (excluding the cost of carbon), it is possible that the cost of providing low capacity factor gas (principally required for winter space heating demand and gas-fired peaking generation) could rise more significantly. This is due to the loss of resources that have historically provided a lot of energy flexibility – particularly the Maui gas field, and the potential exit of Huntly coal-fired generation. The exit of methanol production would also remove a source of energy flexibility able to address extreme situations of scarcity.

Offsetting this reduction in the supply of flexible fossil-energy resources could be a reduction in the demand for flexible energy due to the 'over-build' of renewable generation. Depending on the extent of over-build this could significantly reduce (but not eliminate) the need for gas-fired generation to provide seasonal and dry-year swing.

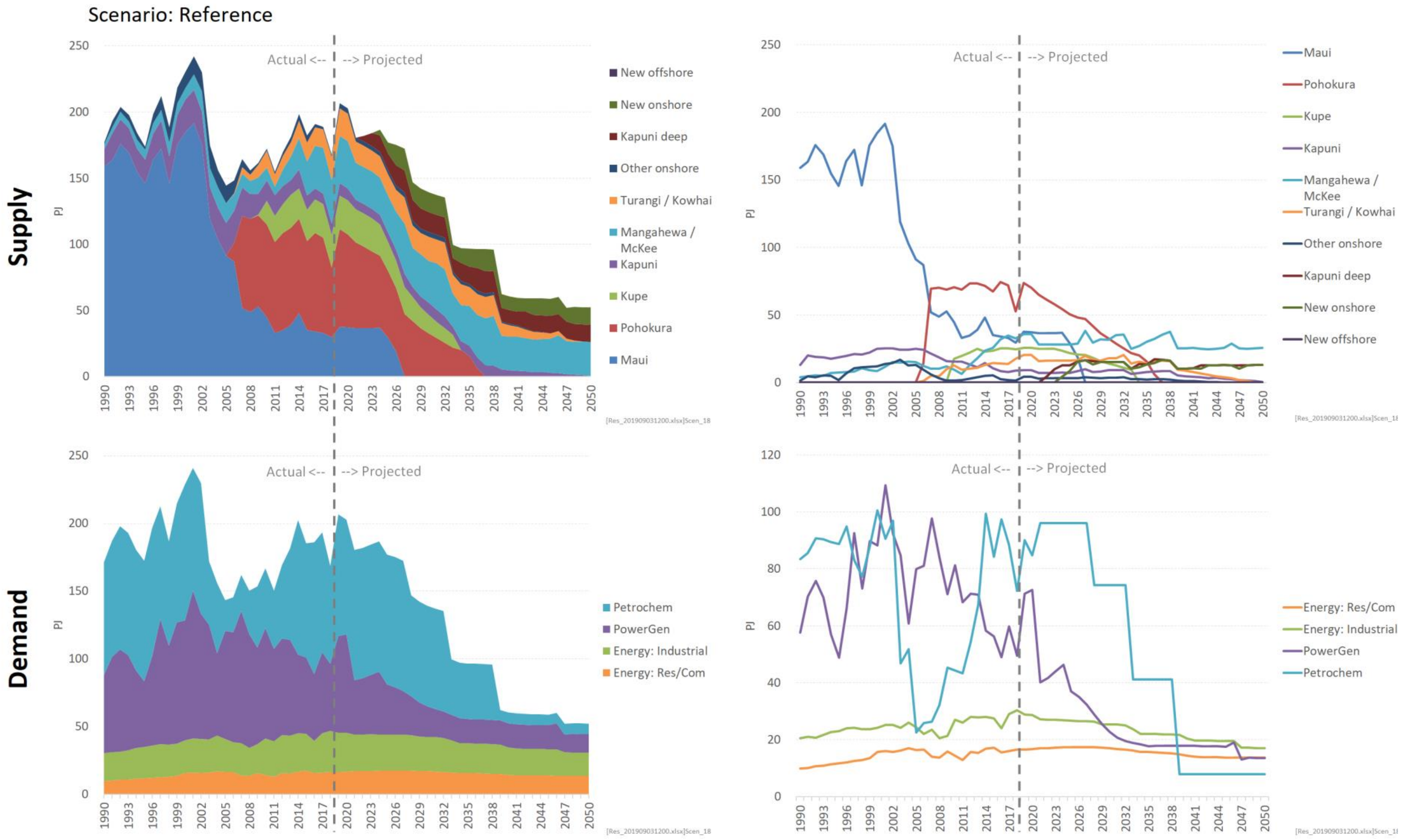
Other factors could also materially alter the supply / demand balance for energy flexibility on different timeframes, including:

- Investment to improve the injection & extraction rates for the Ahuroa gas-storage facility; and
- Large-scale battery deployments – particularly in a mass fleet of EV vehicles.
- Climate change reducing the difference between winter heating and summer cooling demand.

Our modelling has sought to capture at a high-level the effect of many of these factors – particularly the relative costs of providing energy flexibility from gas-fired versus coal-fired generation, and the extent to which over-build of renewables will reduce the need for flexible energy. However, detailed exploration of all of the above factors and the implications on the price of gas for flexible uses, was beyond the scope of this study.

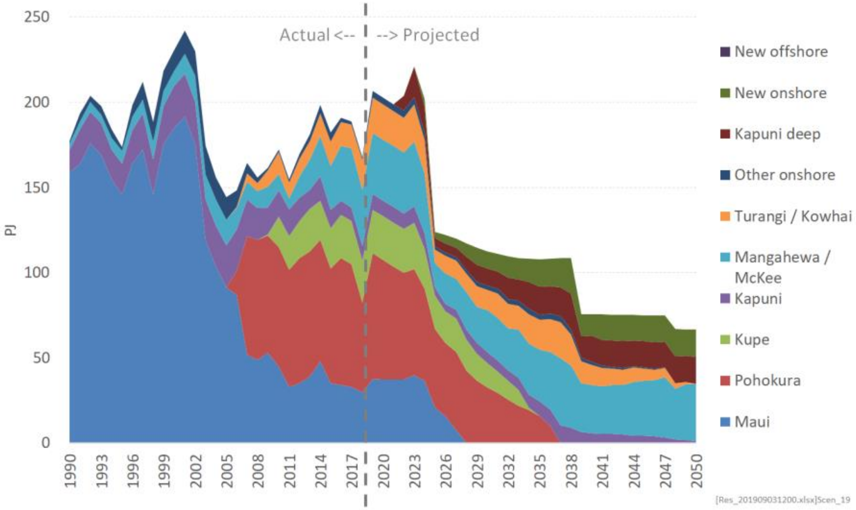
[31] The exit of petrochemical demand will have little impact on gas network cost recovery as the close-to-wellhead location of such demand means that the petrochemical sector contributes little to current network cost recovery. Likewise, the exit of the Taranaki-located TCC baseload gas-fired generator will not have major impact on gas network revenues, but the Huntly-located e3p baseload gas-fired generation will have slightly greater network revenue impact.

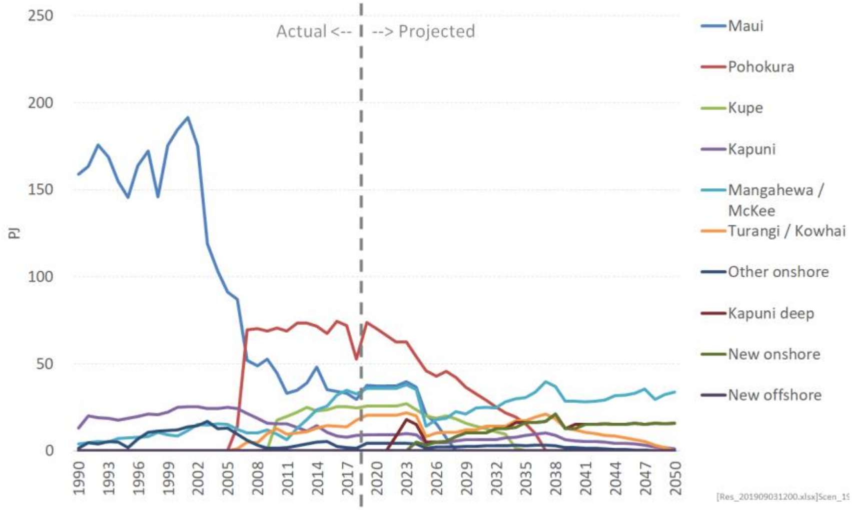
Figure 30: Supply / Demand projections for different scenarios



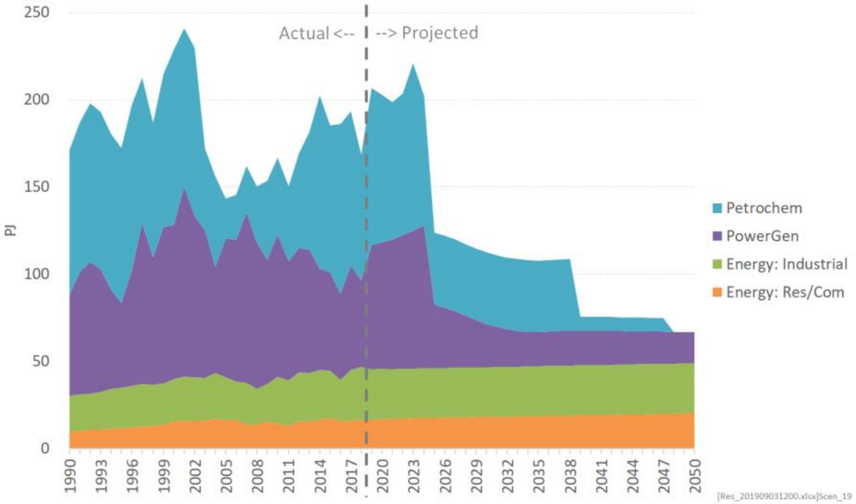
Scenario: Cur CO2

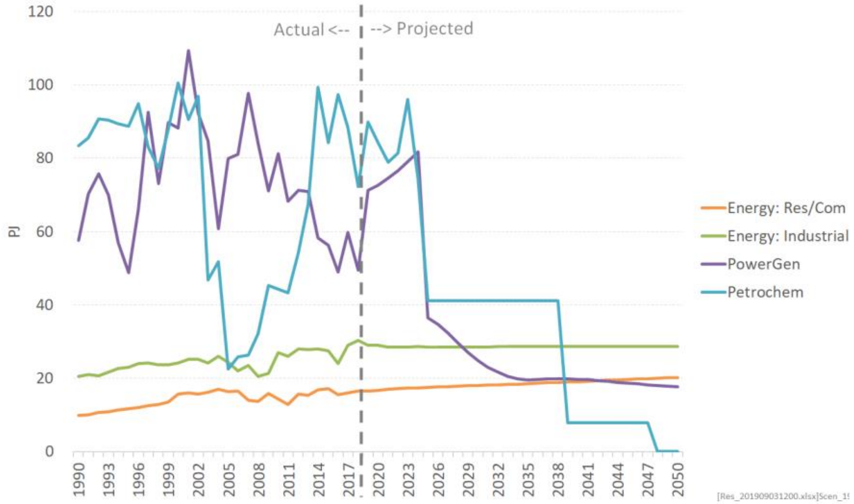
Supply





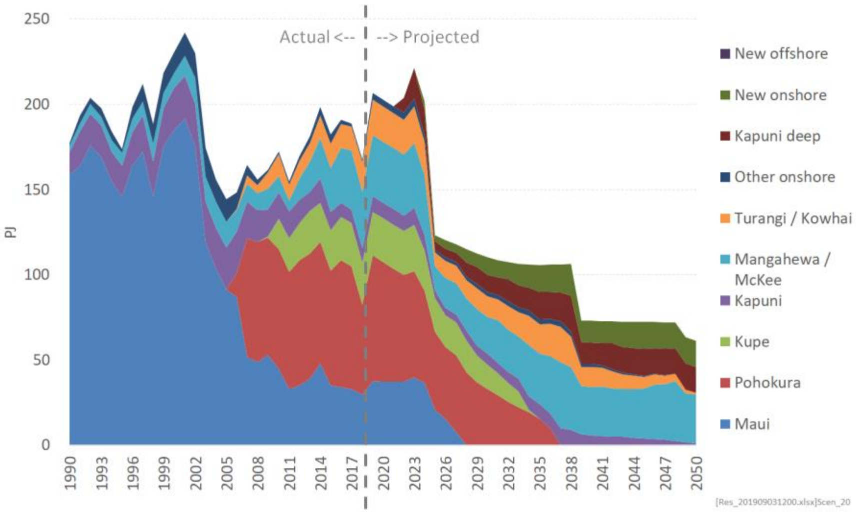
Demand

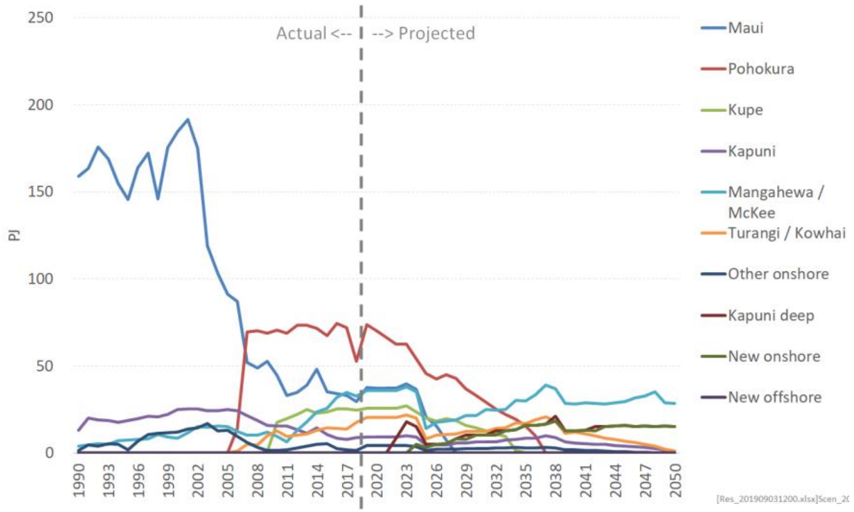




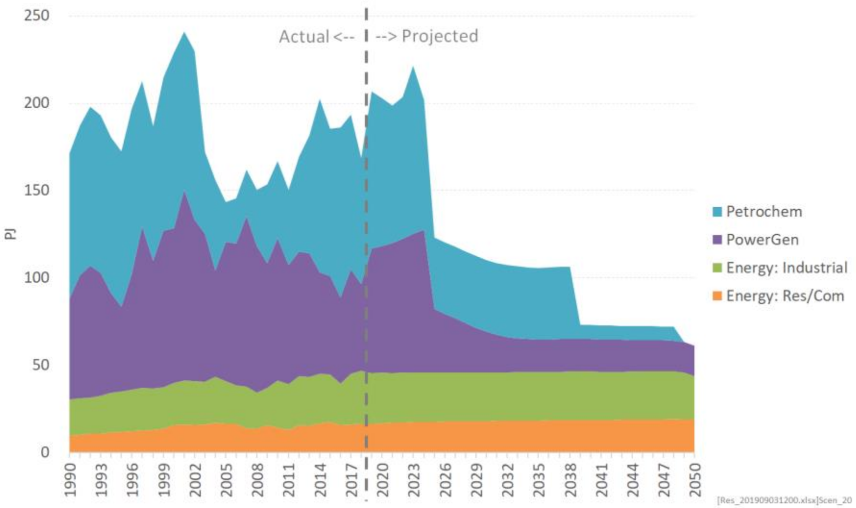
Scenario: Lo CO2

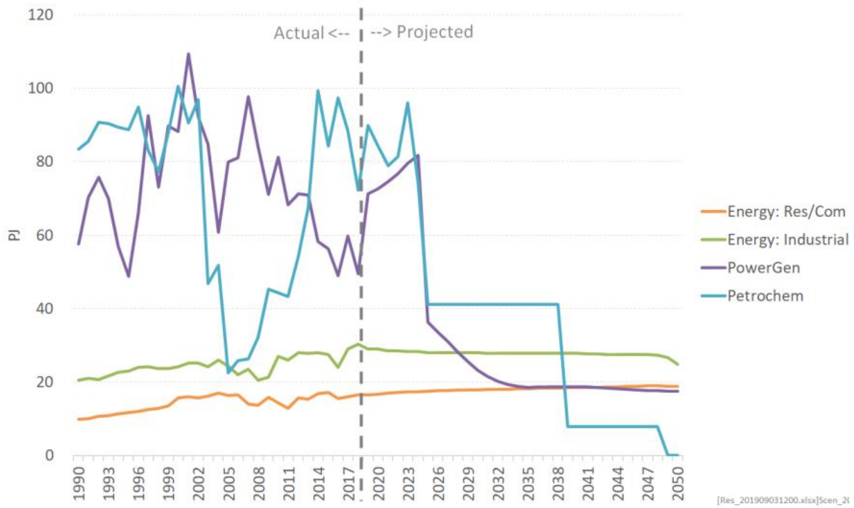
Supply





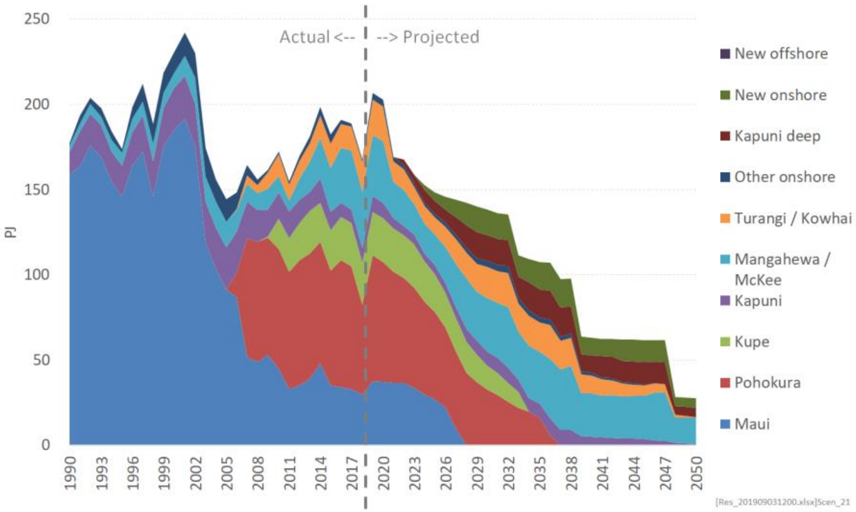
Demand

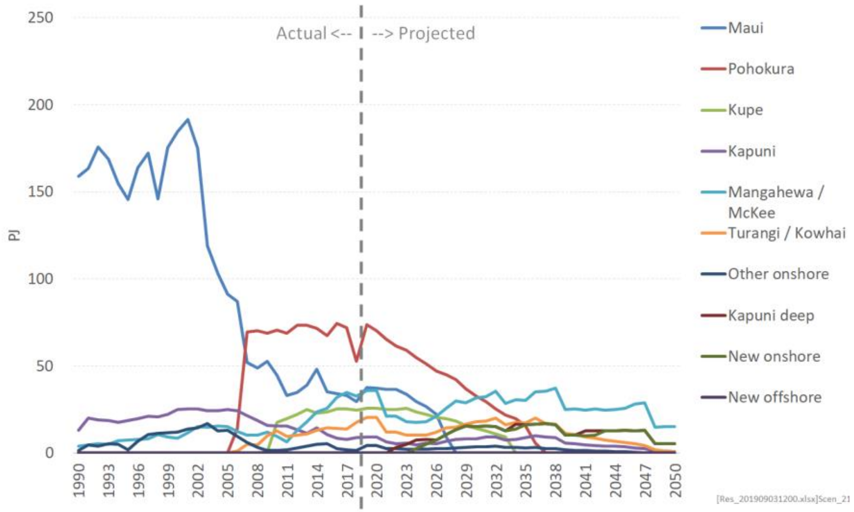




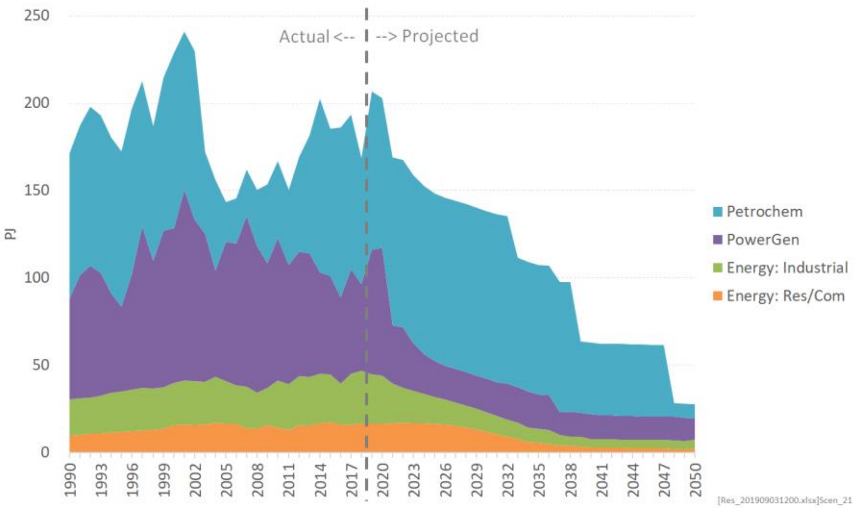
Scenario: Hi CO2

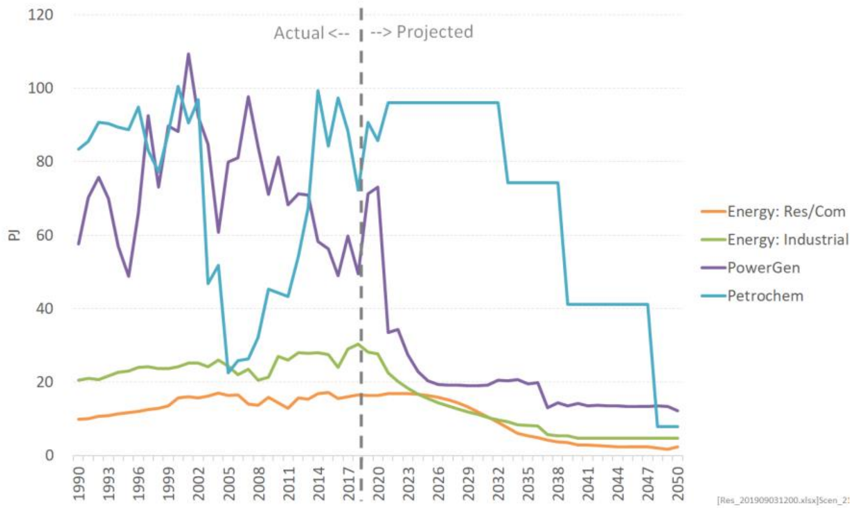
Supply





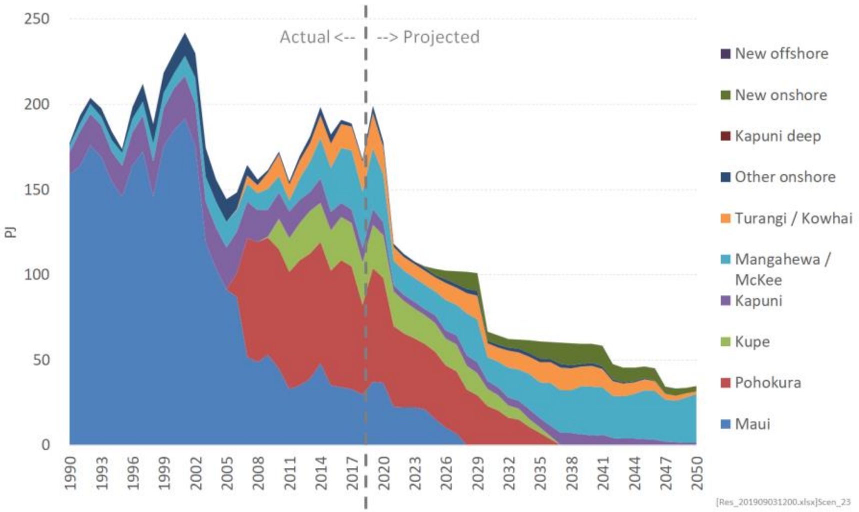
Demand

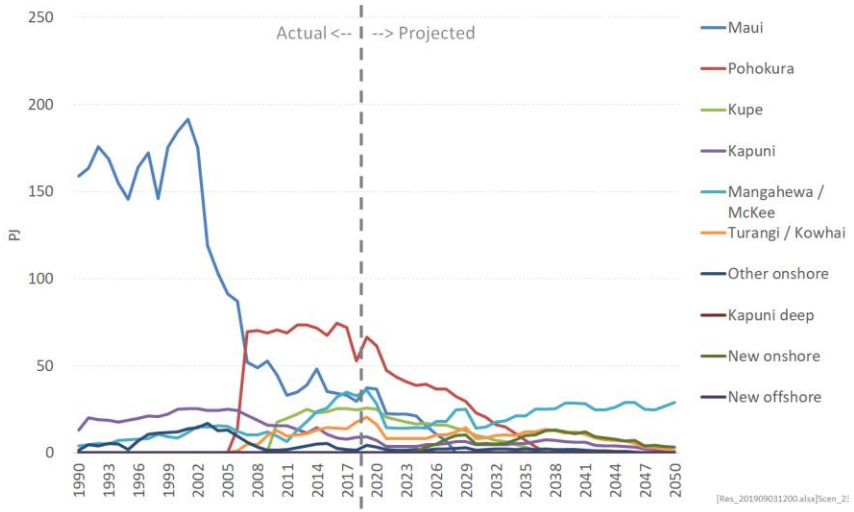




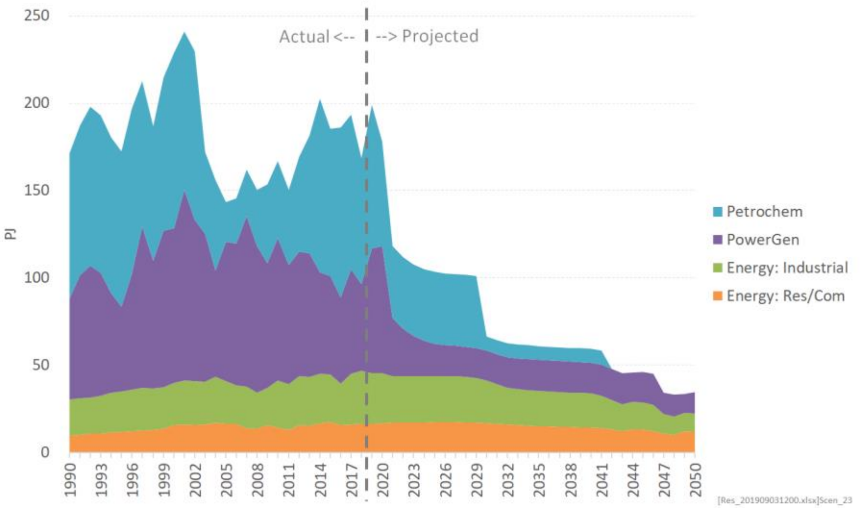
Scenario: Lo resources

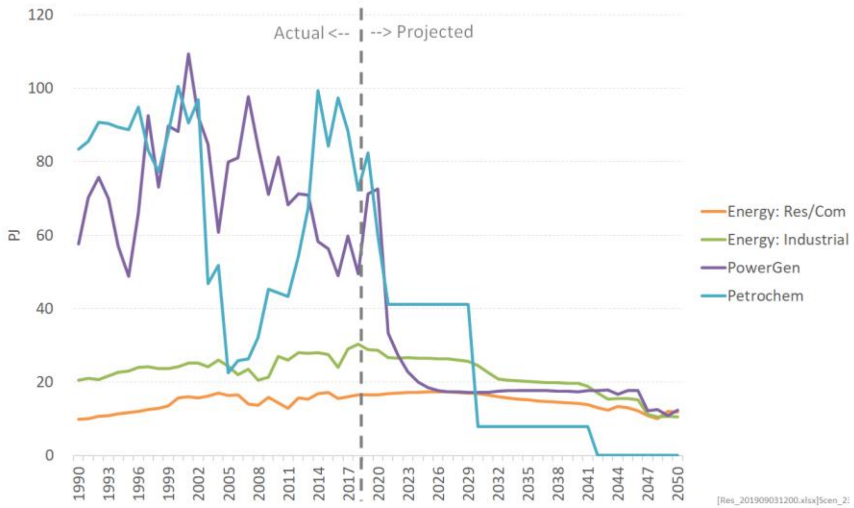
Supply





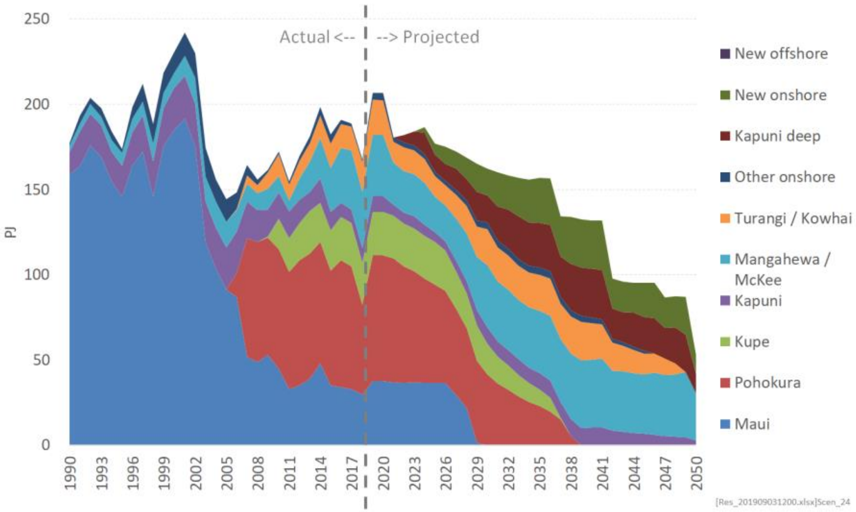
Demand

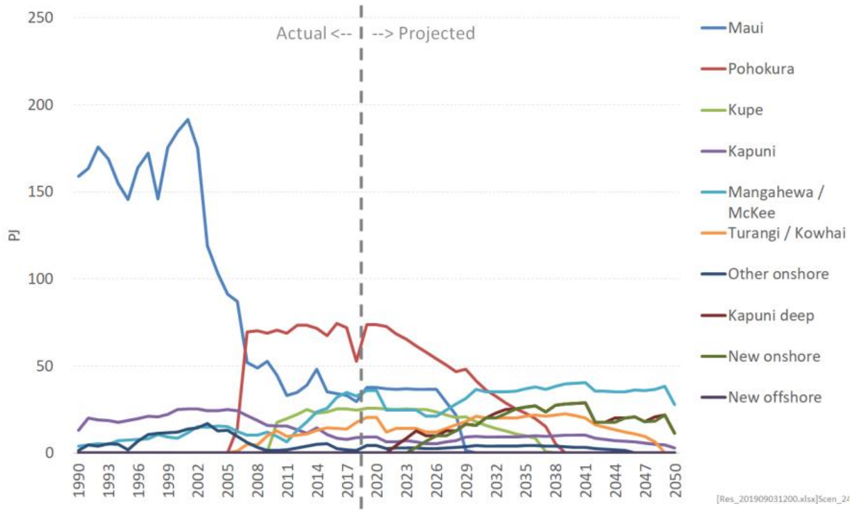




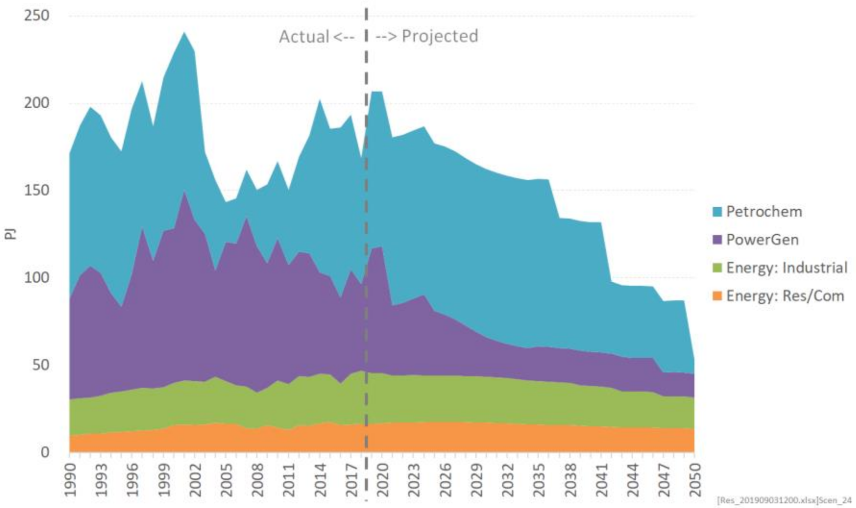
Scenario: Hi resources

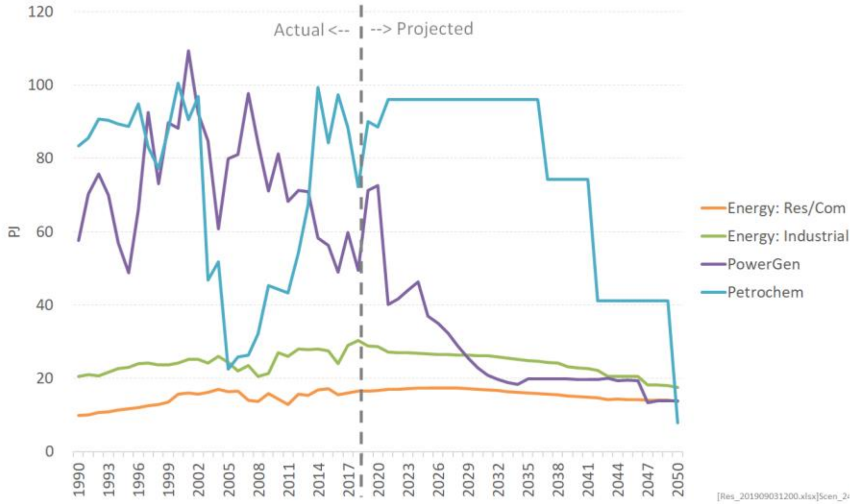
Supply





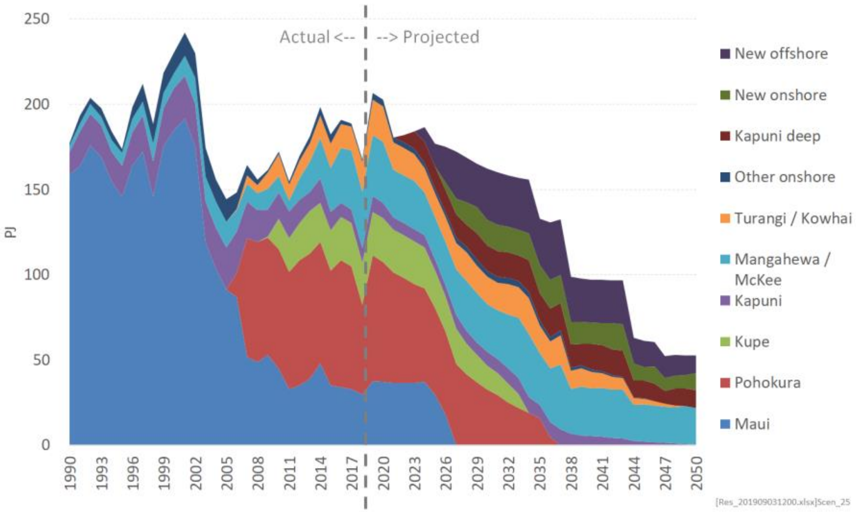
Demand

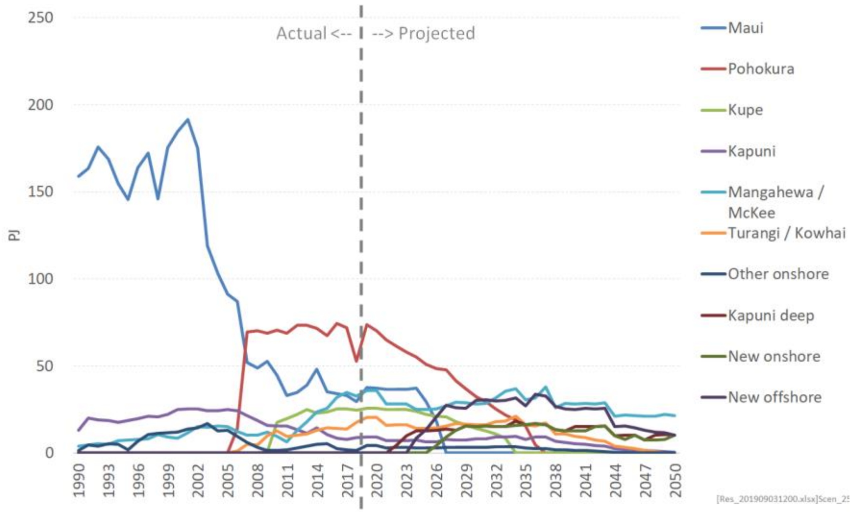




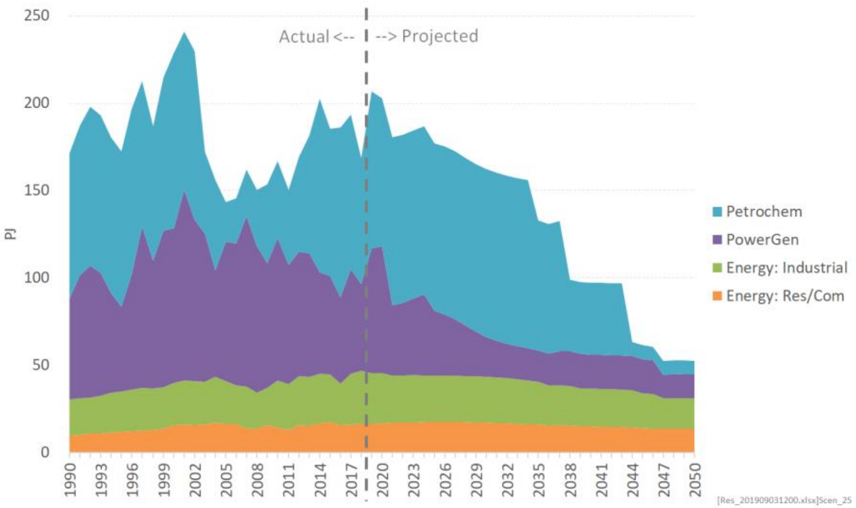
Scenario: New offshore

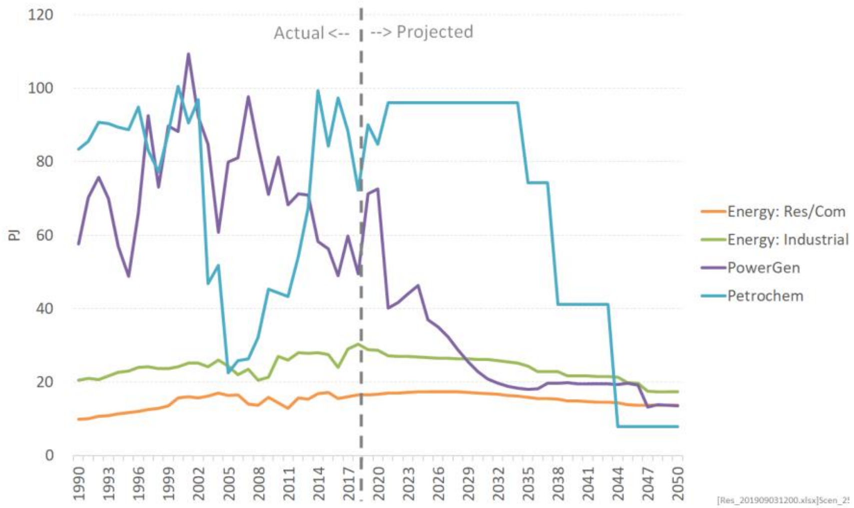
Supply





Demand





5 Deliverability issues and recent gas market conditions

The previous sections of this report have focussed on gas supply and demand projections for the medium to long-term out to 2050, being the principal focus of this study.

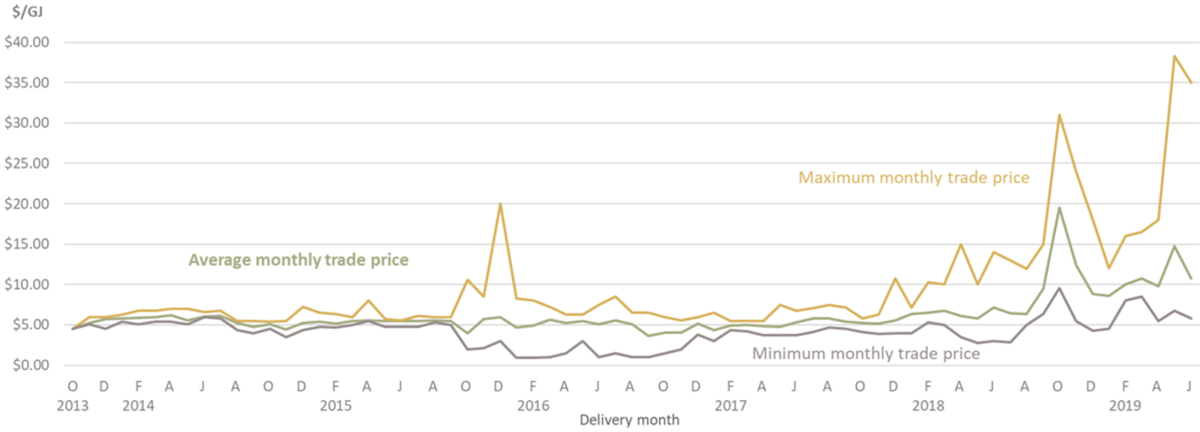
This section briefly comments on recent gas market conditions, particularly the significantly higher gas prices that have been experienced since the middle of last year.

It considers whether, as some commentary has suggested, they are the 'new normal,' reflecting a structural change in the gas market, or whether they are transitory in nature reflecting a temporary situation of supply / demand imbalance.

5.1 Gas supply was tight in late 2018 and early 2019

As shown in Figure 31, up until the middle of 2018, monthly average spot prices were typically around $5/GJ. After mid-2018 they rose substantially and reached $19.5 in October 2018. They fell after October, but monthly average prices were still significantly higher than earlier years. For example, between November 2018 and March 2019 average monthly spot prices were consistently above $8/GJ and averaged more than $10/GJ – approximately double the price in the years from 2014 to 2017. These prices from November 2018 to March 2019 occurred over the summer period when spot prices are traditionally softer.

Figure 31: Monthly average spot prices



Source: Gas Industry Co

Spot prices have also been much more volatile since mid-2018 – with a larger observed range between the monthly minimum and maximum prices. Interestingly, the volatility has been in both directions – with some prices well below the monthly average and some well above.

It should be noted that the majority of gas purchased in New Zealand is through long-term contracts, rather than spot prices. However, it is understood that the relative tightness experienced over recent months has started to flow through to increased gas prices for industrial consumers re-contracting for the forthcoming year(s).

To-date, these tighter market conditions do not appear to have resulted in a material increase in mass-market prices.

5.2 Multiple factors contributed to tight gas market conditions

A range of factors has contributed to the tight gas market conditions. These include:

- **Pohokura outages** - supply from the Pohokura gas field was significantly reduced for much of the period due to planned and unplanned outages. In particular, from September to the end of

December 2018, gas production was reduced by more than 100 TJ per day (roughly 20 percent of national supply) by an unplanned outage to repair a faulty valve. Significant reductions in production were also experienced during parts of March-May 2019 due to a planned programme of well intervention work.

- **Droughts reduced hydro-generation** - dryer than normal conditions reduced hydro generation – especially over the summer period. By mid-March 2019 national hydro storage was approaching the so-called '1 per cent risk curve', indicating a heightened risk of power conservation measures being required. This reduction in hydro generation resulted in increased demand for gas for gas-fired power generators.
- **Underlying power demand growth** – after several years of flat electricity demand, the last eighteen months has seen underlying electricity demand growth again, due to population growth and the resumption of full operations at the Tiwai aluminium smelter. Electric vehicle uptake is also starting to grow demand. While this rising electricity demand has now triggered new investment in renewable generation, the first significant new renewable projects aren't expected to be commissioned for at least 18 months. Until this time, demand growth is typically being met by increased thermal electricity generation (gas and coal-fired) – being the principal swing source of flexible generation.
- **Strong petrochemical gas demand** – aside from a planned outage at Waitara Valley in late 2018, all petrochemical plants have been available for operation and there has been strong demand for gas.[32] In fact, anecdotal evidence indicates petrochemical production was constrained at times in the period due to gas availability.
- **Other planned outages** – summer is the traditional period for undertaking planned maintenance on gas production and coal-fired electricity generation plant. Operators sought to defer these in some cases, but this was not always possible due to the long lead times or operational requirements. These other outages further tightened the supply/demand balance.

5.3 Recent gas prices are unlikely to be the 'new normal'

While recent conditions have persisted for some months, we think it unlikely that recent gas prices will become the 'new normal'. The fundamental reason for this view is that significant cuts in gas demand would be expected if recent prices were to be expected on a long-term basis. Any such demand changes would likely centre on baseload power generation and petrochemical production because these industries are large and have higher sensitivity to gas prices than most sectors.

As discussed in section 4, our Reference projection has gas-fired baseload power generation gradually displaced over the next decade or so by new renewable generation due to rising carbon prices. A similar outcome would be anticipated from an expectation of sustained high gas prices, except the transition would likely be much shorter – noting that \$1/GJ movement in gas price is equivalent to \$19/tCO_2.

Figure 48 on page 82 in the appendix indicates that if gas prices were to settle at approximately \$8/GJ, and the long-run marginal cost of building new wind generation (including firming costs) was approximately \$65/MWh, then it would be economic to displace existing gas-fired baseload power generation if carbon prices were zero. In this respect, it is worth noting that the expectations of the required price for new wind in New Zealand are approximately \$65/MWh, and the expectations of carbon prices are higher than \$25/tCO_2e.

[32] See www.gasindustry.co.nz/dmsdocument/6530%20fig%2026, p19.

Likewise, a substantial scaling back of petrochemical gas demand would be likely if Methanex were to expect ongoing gas prices at recent levels, as such levels are greater than our assessment of Methanex's long-term willingness-to-pay for gas – as set out in section 6.5.1 of the Appendices.

Power generation and petrochemicals production account for over 70 percent of total gas demand. A fall in demand from these sectors would seriously impact on gas producers' revenues. This factor, in combination with the strong driver on upstream producers to maximise their revenues from oil sales, makes it very unlikely that prices will remain at recent levels.

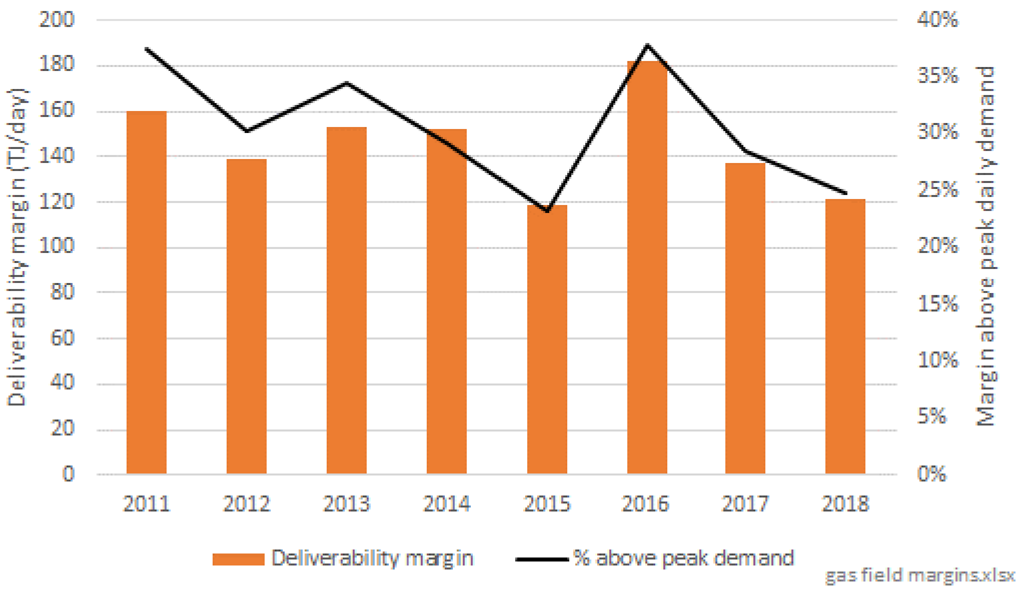
Finally, we note that many of the factors contributing to recent high prices are transitory in nature and are already unwinding:

- We understand repair work on the Pohokura production facilities has been completed, and OMV as operator is now pursuing investment plans to extend the period of peak production from the field.
- Similarly, the drought conditions seen in early 2019 have eased, and national hydro storage was above average levels by May 2019.

It is important to emphasise that these observations apply to *average* gas prices. As noted above, recent conditions have also seen a marked step up in spot price *volatility*. The drivers for this change are less clear, but it is possible that daily deliverability is becoming tighter relative to demand.

One indicator that tends to support this view is the estimated deliverability margin (i.e. peak daily gas production capability minus peak daily demand)[33]. This indicator seeks to measure the level of buffer available in the gas production system to address outages (full or partial) at gas fields or production stations.

Figure 32: Estimated deliverability margin[34]



Source: Concept analysis of OATIS data. Daily gas production capacity is estimated.

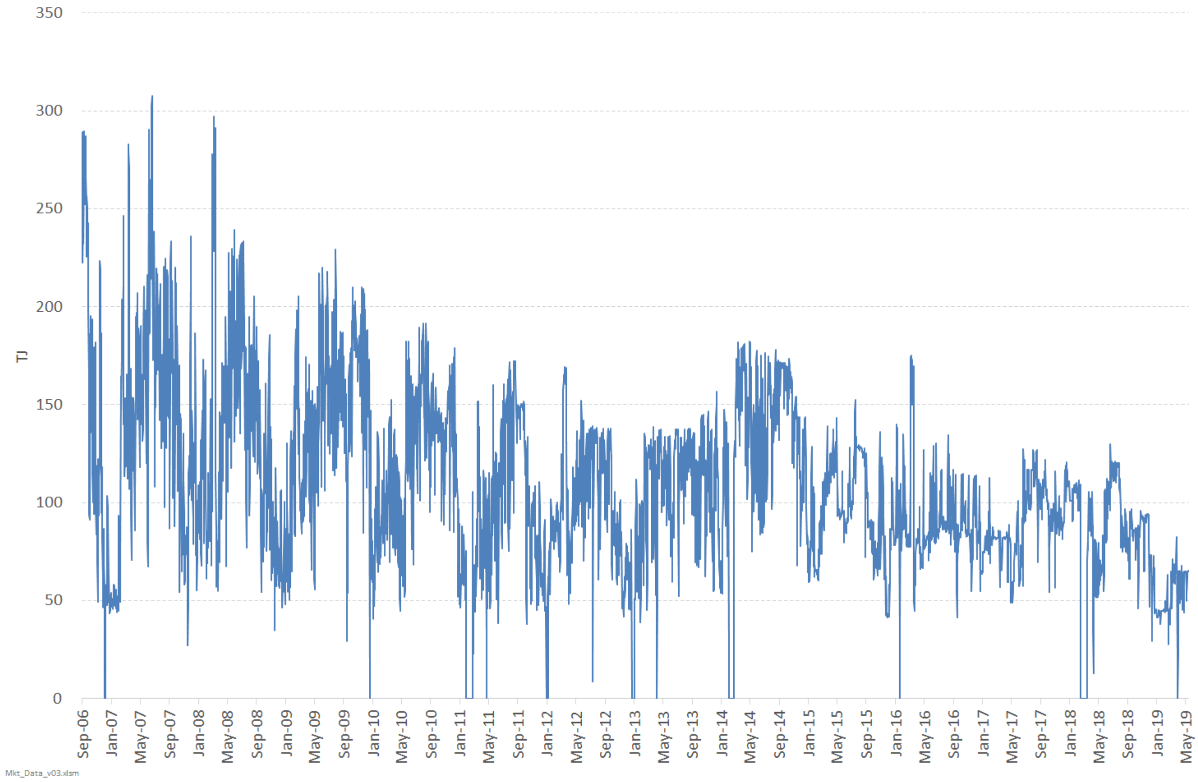
[33] We estimate daily deliverability based on observed peak production in the previous year for each field. These are summed to estimate national deliverability. The resulting estimates are subject to some uncertainty but should provide a reasonable measure of trends over time.

[34] The change in 2016 was due to two main factors. On the demand-side, both Otahuhu and Southdown power stations ceased operation, reducing the overall level of coincident peak demand. On the supply-side,

This analysis shows there has been a positive deliverability buffer through the period since 2011, but it has been trending downwards over time. This may in part explain the increased price volatility seen in 2018 and early 2019.

A significant factor driving this reduction in deliverability has been the decline in the deliverability from the Maui gas field as illustrated by Figure 33.

Figure 33: Daily gas production from the Maui gas field from 1 Sep 2006 to 15 May 2019



Source: Concept analysis of Oatis data

Output from the Kapuni field has also been in steady decline over the past five years, although the scale of effect is considerably less than that of the decline in the Maui field.

Looking ahead, we are not able to predict the likely trend in price volatility. However, factors which we expect will be relevant include:

- the degree to which gas producers invest in the provision of gas deliverability. In this respect, there is an expectation that investments will be made over the next few years in developing the contingent resources for the Maui and Kapuni fields. If these go ahead, it would boost production capability above the levels seen recently.
- the extent to which other sources of fuel flexibility – such as underground gas storage, swing from gas/coal switching at the Huntly power station, and demand response from large gas users –are available to users. In this respect, Firstgas Group has plans to increase the deliverability from the Ahuroa gas storage facility. Counteracting this is the potential decline in flexible energy

the P99 level of output observed from Maui was higher. It is important to note that deliverability cannot be observed directly, and the P99 output is used as a proxy. As it happens, the Maui P99 output in 2016 coincided with a complete Pohokura shutdown. So it is possible that Maui's deliverability in 2016 did not actually increase that year, but was simply called upon. A significant drilling programme was undertaken at Maui over the period 2012-2014 – which more than doubled remaining reserves and it seems likely that it would also have enhanced deliverability.

if coal-fired generation at Huntly were to cease, and the exit of methanol production would remove a source of energy flexibility to address extreme situations of scarcity.

- trends in the need for gas flexibility – especially from the power generation sector to address variability in generation from renewable sources.
- investment in renewable generation. As already set out, there is the potential for renewable investment not just to bring the electricity supply / demand balance back to the levels seen prior to the increase in electricity demand, but to go beyond and completely displace baseload thermal power generation. If this were to happen, it would substantially reduce the requirement for gas market deliverability.

APPENDICES

6 Appendix: Detailed analyses of key demand-using segments

6.1 About this appendix

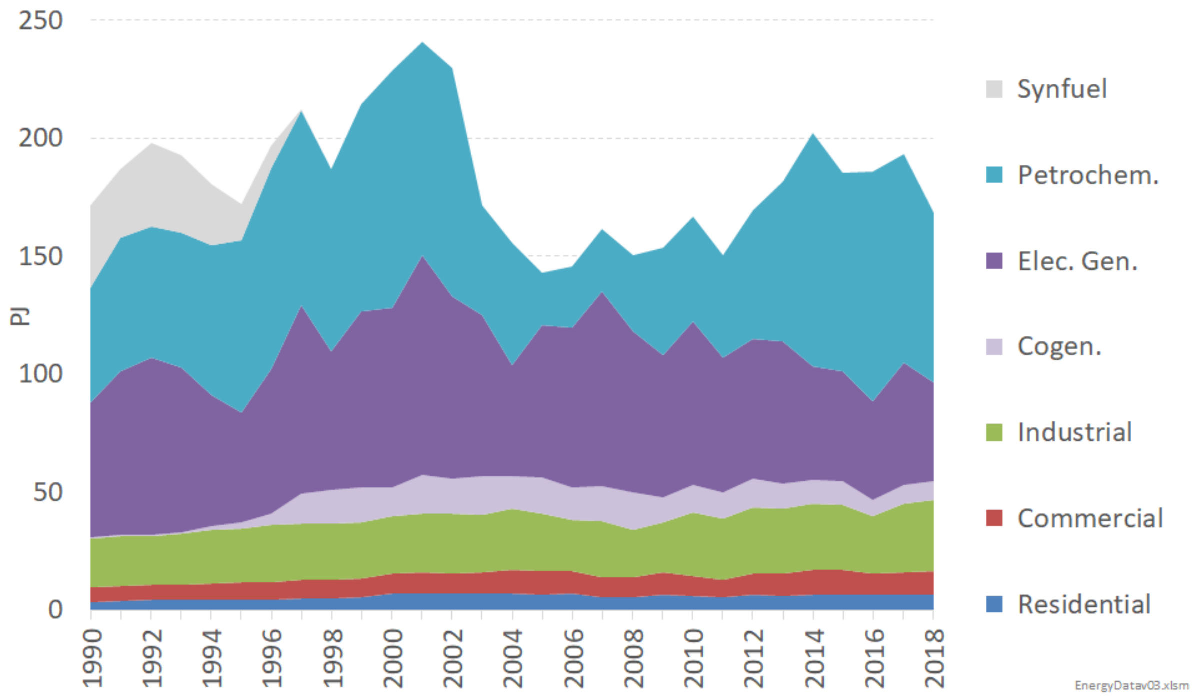
This appendix sets out more detailed analyses of the factors driving the demand for gas from the different gas-using segments, and how the competitiveness of New Zealand gas will change due to changes in carbon price or the underlying gas price.

This analysis considers New Zealand gas demand under four key segments:

- Mass-market (residential and commercial) use for heating energy. (Principally space and water heating)
- Industrial use for heating energy. (Principally process heat)
- Power generation (both electricity-only and cogeneration)
- Petrochemical production (using gas both as a feedstock, and as an energy fuel)

Figure 34 shows how demand from these segments has varied over time.

Figure 34: Historical gas demand from different segments



Source: Concept analysis using MBIE data

We discuss each segment in turn, analysing the drivers of outcomes in each segment, including the sensitivity to potential future carbon and gas prices.

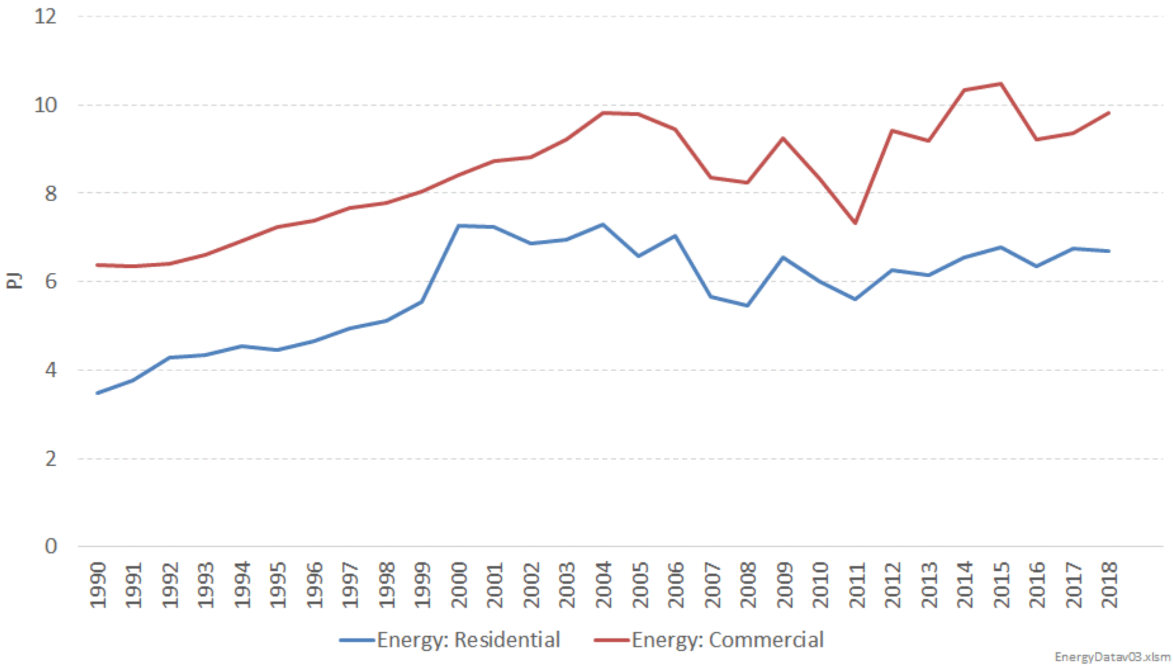
6.2 Mass-market demand affected by non-price factors

Figure 34 previously showed that commercial and residential gas demand are small components of total demand—5 per cent and 3 per cent in 2017 respectively.[35]

Figure 35 shows demand for these sectors since 1990. This data relies on submissions to Statistics New Zealand by retailers who are supplying gas to consumers. This is understood to have given rise to consistency issues as consumers switch between retailers who, for statistical submissions purposes, have classified such consumers differently. This manifests as year-to-year variability.

Nonetheless it gives a reasonable gauge of general trends, which indicate that commercial demand grew steadily until around 2004, and residential until around 2000. Demand then fell for both sectors, but over the last ten years there has been steady growth such that demand in 2017 was 14 per cent and 23 per cent higher than in 2008 for commercial and residential segments, respectively.

Figure 35: Historical residential and commercial gas demand since 1990



These trends reflect several factors:

- Growth in new gas connections driven by population and economic growth. There have been 30,000 new active connections since 2009.
- Energy efficiency improvements, which have encouraged reduced gas use, particularly for residential consumers.
- Competition with alternative energy options. In particular, heat pumps have emerged as a key competing technology for residential space-heating. Bottled LPG is another source of competition, as we discuss later.
- Changes in consumer prices, with real residential gas prices having increased by around 92 per cent since 2000, while real residential electricity prices increased by around 53 per cent over the same period.

[35] We consider 2017 a more representative 'normal' year, as 2018 featured significant gas supply interruption from the Pohokura gas field which resulted in curtailment of demand from the petrochemical sector in particular.

6.2.1 Gas is currently an economic option for space and water heating in many situations

Figure 36 estimates the total costs a medium-sized residential consumer would pay today for domestic space and water heating, for a range of different appliance options – including natural gas. For this analysis:

- The costs are shown per kilowatt-hour of *useful* heat – i.e. taking account of the efficiency of the appliances.[36]
- The lower coloured portions of the bars are day-to-day running costs, including the costs of the fuel itself, variable network charges, and carbon costs based on a price of \$25 /tCO_2e. It also includes periodic maintenance costs for the heating appliance.
- The grey portion of the bars are the costs of purchasing and installing the heating appliance 'variablised' across its total lifetime heat output. For an existing appliance, these costs are sunk and need not be considered.
- Most consumers will also pay a fixed charge (usually daily) to cover the costs of providing network and retail services that do not vary based on how much fuel is consumed. New gas consumers may also face additional up-front costs to establish a network connection. These fixed costs are shown at the top of the bars for gas and LPG.

  While electricity users face similar costs, gas and LPG are discretionary fuels whereas electricity will be used regardless for lighting and to run appliances and electronics. Therefore, these fixed network and retail costs do not need to be factored in for electricity. However, the significance of the fixed costs for gas and LPG will depend on the extent to which the specific gas or LPG application is discretionary or not. For example, if a consumer were considering gas for hot water heating, but they would have gas regardless for cooking or space heating, then its use for hot water need not consider the fixed connection costs at all. The effect of accounting for these fixed costs across both space and water heating water is shown by the darker hatched portion of the bar. The lighter hatched portion shows the additional effect of spreading them solely across water heating or space heating.

[36] For example, in order to supply 100 kWh of useful heat from an appliance which is only 50% fuel efficient, the appliance would consume 200 kWh of fuel.

Figure 36: Lifetime costs for different space and water heating technologies[37]

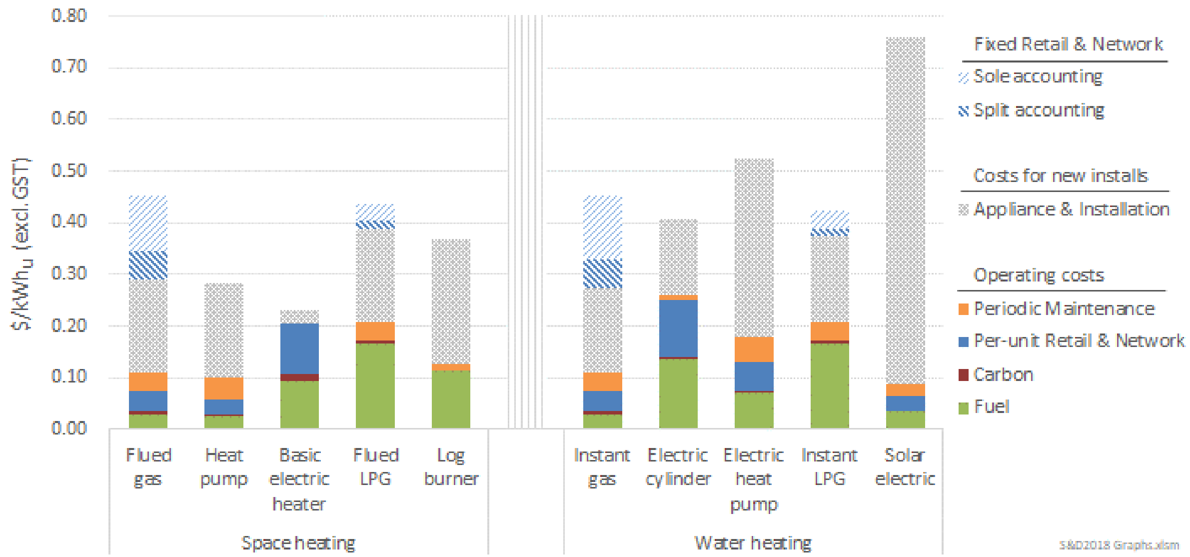


Figure 36 illustrates some key points that inform the outlook for gas demand from mass-market consumers:

- Carbon costs are currently a very small component of total heating costs for all space and water heating options for these consumers.
- The upfront appliance capital costs of the different heating options have a dominant effect on the economics of any option.
- Gas fuel costs are a small component of overall heating costs, but the fixed retail and network costs for gas can add significantly to total heating costs. From a whole home heating requirement, gas can often be cheapest. However, evaluating water or space heaters on their own, and apportioning the fixed network and retail charges entirely to that heater can result in the gas-fired heater appearing to be more expensive.

6.2.2 For existing users, gas remains competitive even at very high carbon prices

We have built on the analysis in sections 6.2.1 to consider how the economics of gas for space and water heating will be affected by higher carbon prices.

The economics of switching from gas to electricity will vary depending on:

- whether the consumer has an existing gas appliance (with sunk capital costs),
- whether the consumer will only use gas for space or water heating (in which case the fixed charges should be included in the evaluation of each option), or whether gas will be used for both (in which case the fixed charges should be excluded or reduced for the evaluation)
- the underlying carbon price and the effect this has on the emissions of electricity.

However, this latter issue is decidedly non-trivial to evaluate.

[37] Figure 36 is broadly based on the same analysis that we presented in our Consumer Energy Options 2016 update report for the Gas Industry Company. That report provided detailed discussion about the assumptions used, and how the costs of different heating options vary significantly based on factors such as how much a consumer uses, where they live, and the effect of different approaches for *structuring* network and retail tariffs – e.g. network cost allocation between groups, the balance between fixed and variable charges, and time-of-use structures. We do not repeat that discussion and analysis in this report.

Electricity has a carbon component because 18 per cent of the electricity generated in 2017 was from gas-and coal-fired stations. However, it would be wrong to say that all electricity demand has the same carbon component.

Importantly, the carbon-intensity of electricity demand varies according to the *profile* of electricity demand. Electricity demand can be met more readily by renewable technologies if it is consistent over time, whereas it is more likely to be met by fossil-fuelled generation if it occurs mainly in the evening and/or in winter—periods when demand is highest. As is set out in more detail in section 6.4, this is because fossil generation is the principal technology to provide infrequently-used generation to meet periods of peak demand that can't be met by the 'sculpting' of hydro generation. This results in very different emissions intensities for different electricity uses:

- Space heating is used almost exclusively in winter and more heavily focussed in morning and evening peaks. This means space heating electricity demand is hence almost entirely met by fossil fuelled generation and so has a relatively high emissions-intensity.
- Electric water heating is less emissions-intensive, primarily because it is more constant throughout the year, but does have a strong within-day shape.
- Refrigeration has a lower emissions intensity because the profile of its demand is largely flat throughout the day and year, and thus met by renewable generation. It is not completely zero because some of this renewable generation is geothermal power which has an emissions intensity roughly one-sixth of that of a combined-cycle gas turbine (CCGT) power station.

Looking forward, the carbon-intensity of electricity is likely to decrease as carbon prices increase, because electricity will be increasingly generated from renewable technologies (discussed in section 6.4) displacing fossil stations from their different duties.

The first type of fossil generation to be displaced by renewables will be baseload gas-fired generation. We estimate this is likely to be when carbon prices rise above \$30-60/tCO_2 – noting that as the cost of new wind generation continues to fall, the carbon price to displace baseload gas-fired generation will also fall.

As carbon prices increase further, it will start to become economic to progressively displace fossil stations from providing some of the peaking generation to meet within-day and seasonal peaking demand. In addition, as carbon prices rise, it is likely that growth in baseload electricity demand will tend to increasingly be met by wind, rather than geothermal, reducing the emissions intensity of baseload electricity demand such as refrigeration.

Figure 37 shows the results of some high-level modelling estimating the emissions intensity of different electricity uses, across a wide range of carbon prices, based on the general load shape of those uses.

Figure 37: Modelled emissions intensity of different electricity demand profiles at different carbon prices

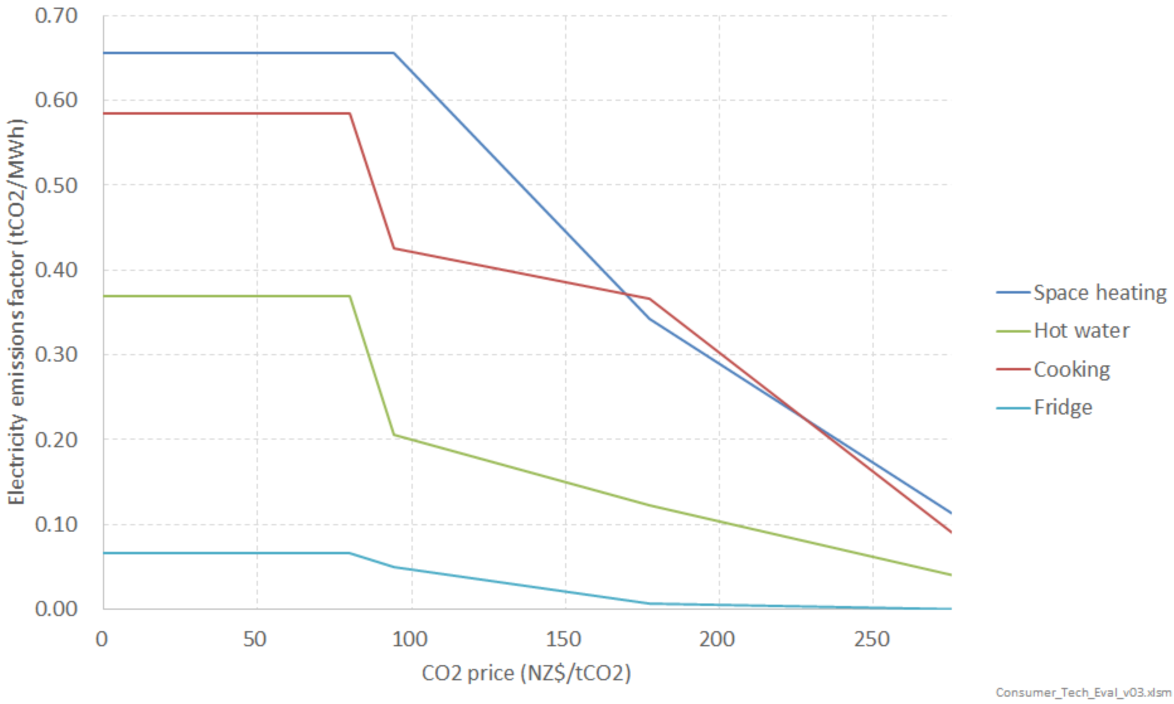


Figure 38 and Figure 39 bring together the analysis illustrated in Figure 36 and Figure 37 previously, show how the economics of different water and space heating options vary with carbon prices for different fuels, appliances and consumer situations (whether a consumer needs a new appliance or has an existing appliance).

Figure 38: Variation in cost per kWh of useful heat with carbon prices for different space heating options

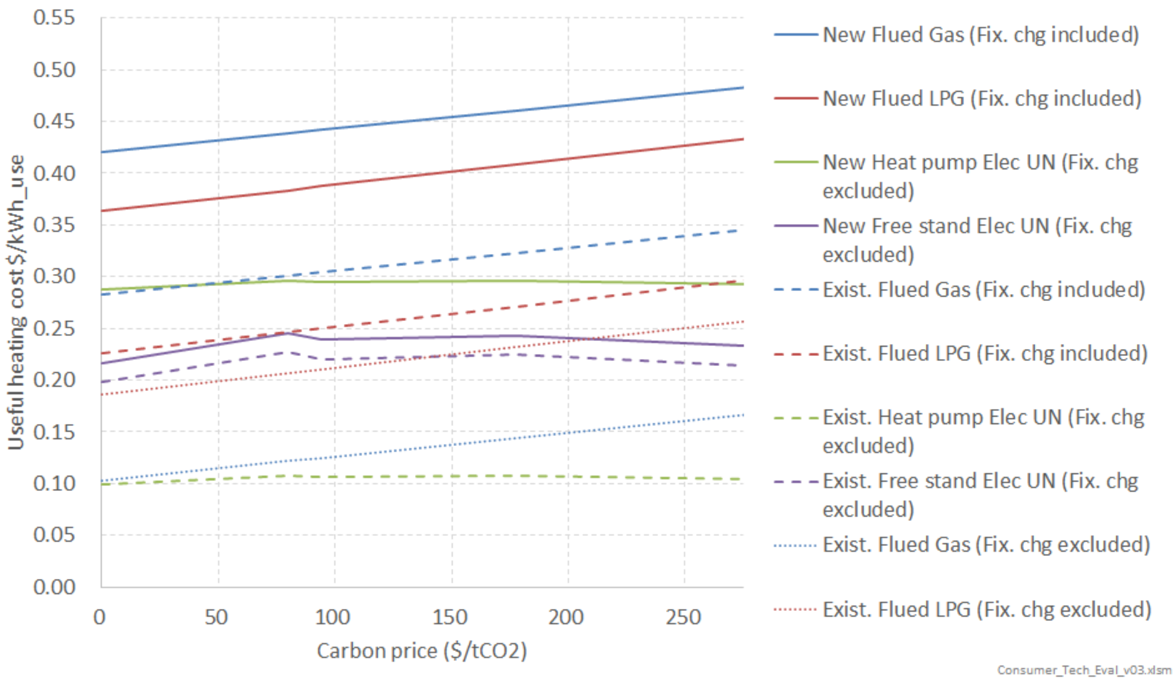
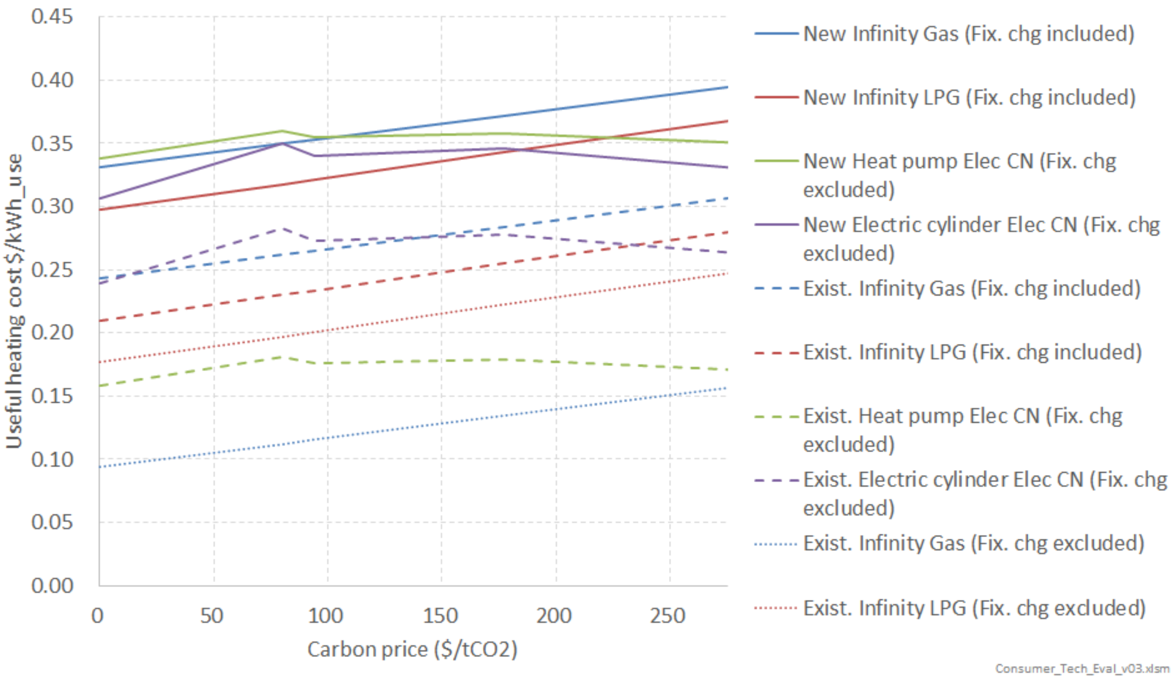


Figure 39: Variation in cost per kWh of useful heat with carbon prices for different water heating options



The key take-aways from this analysis are:

- It is not cost-effective for consumers with an existing gas heating appliance to switch to electricity if gas fixed charges are not included.
- However, if fixed charges are included, it can start to become cost-effective to switch away from gas space heating to electric heating as carbon prices rise
- If a consumer needs to purchase a new gas appliance (e.g. in a new-build situation, or their existing appliance has reached the end of its life), then electric options are cost effective for space heating, but gas is still cost competitive for water heating. Only at very high carbon prices does electric water heating start to become cheaper than gas water heating – although the difference is not large.
- The effect of all these different factors (plus variance in the amount of heat demand by different consumers – although this effect is not shown in the above graphs) means there is a very wide range of threshold carbon prices at which it becomes cost-effective for consumers to switch from gas to electricity.

The above analysis is based on current electricity and gas network tariffs. However, from an economic whole-of-New-Zealand perspective, the sunk nature of gas network costs means that gas-fired water heating options are likely to be least-cost in most situations—even for very high carbon prices—and gas-fired space heating is likely to be least-cost in more situations.

This is because, particularly since the retirement of Otahuhu B and Southdown gas-fired power stations in Auckland in 2015, there is surplus capacity on the gas network, so gas demand is unlikely to give rise to a material need for investment. This is not so for electricity—some parts of the transmission and distribution networks will have limited capacity to accommodate demand growth during winter evenings, such as space heating. Any necessary upgrades would increase costs for consumers.

This creates a challenge for gas network companies as to how best to structure their gas prices to residential and commercial and industrial customers in a way that maximises the relative competitiveness of gas across all these customer segments. Thus, decisions around network cost allocation between groups, and how to structure charges between fixed and variable components[38] are likely to be increasingly important to maximise the competitiveness of gas and deliver least-cost outcomes for New Zealand.

It also highlights the need for electricity transmission and distribution pricing to become more cost-reflective, to signal the network cost implications of increased electricity demand at different times of the day/year and locations.

6.2.3 Non-price factors could be a more significant factor in determining future space and water heating fuel choices

The above analysis has been based purely on economics. However, non-price factors can significantly impact consumer decisions. This presents both an opportunity and a risk for mass-market gas demand.

Instant gas water heating has 'quality' benefits that are highly valued by some consumers, such as never running out of hot water and not taking up interior house space. Consumers will be willing pay more to acquire these benefits that are less achievable with electric cylinder-based options. The latter benefit can also create a physical barrier to switching away from gas that can support continued demand.

Gas space heating has quality benefits as well—particularly aesthetic ones, and it is also the most practical option for central heating for larger houses and for heating homes quickly upon returning home.

Recent LPG uptake supports the idea that people will switch away from electric hot water cylinders which may be lower-cost on a c/kWh basis in order to get the superior quality benefits of gas water heating. Since 2008, annual demand for LPG in 45 kg cylinders in New Zealand has grown from 32,000 tonnes to 85,000 tonnes in 2017. Of this growth, 23,000 tonnes was in the North Island. Industry stakeholders have informed us that hot water heating is the primary driver behind this uptake—though consumers may then also use it for cooking and space heating.

While there are these quality benefits of gas appliances, another non-price factor which may affect consumer demand in the other direction is public perceptions of gas as a fossil fuel, and some consumers' potential decisions to switch to electricity for environmental reasons.

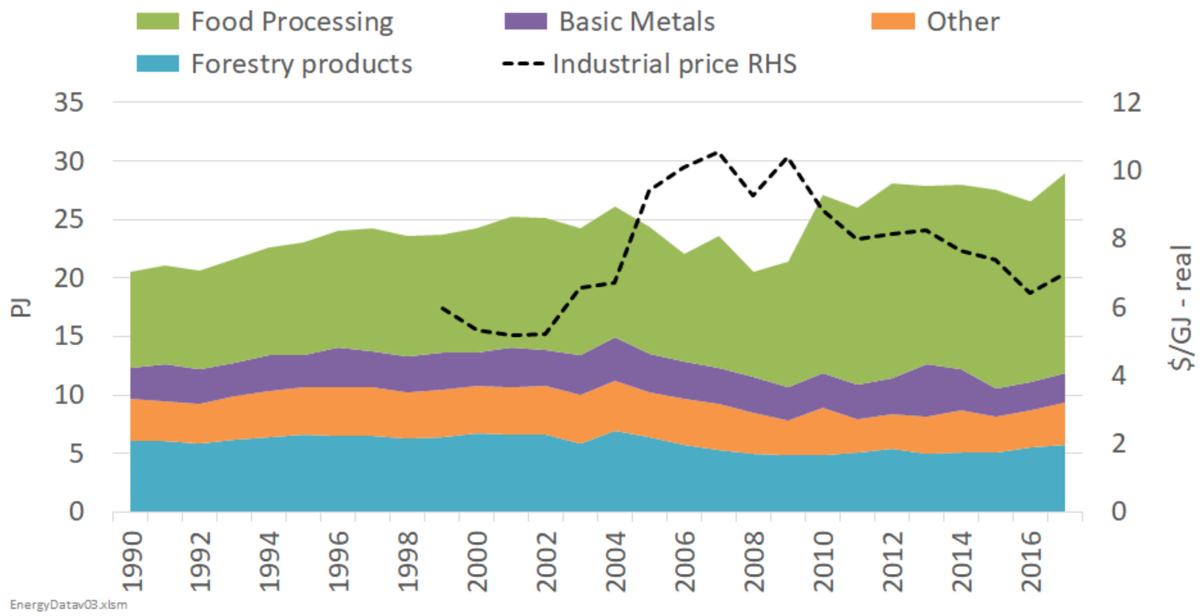
It is inherently hard to estimate the extent to which these non-price factors will support or reduce the demand for gas from mass-market consumers. Our assessment is that the overall effect will be to further increase the effective range of threshold carbon prices at which mass-market gas to electricity switching will occur.

6.3 Industrial use can withstand significant price uplift but not significant supply uncertainty

In 2017, industrial users consumed 29 PJ of gas, which was around 15 per cent of total New Zealand gas demand. Over half of the gas used was for food processing—primarily dairy. The rest was from the forestry and metals (i.e. steel) industries, and various other manufacturers. This is shown in Figure 40, which also shows the industrial gas-use price.

[38] For example, some gas networks have chosen to offer 'low-user' tariff options with lower fixed charges and higher consumption related charges, in part to strengthen longer term demand.

Figure 40: Breakdown of industrial gas use (excluding chemicals) and average price since 1990



As with the residential and commercial data shown in section 6.2 this data relies on submissions to Statistics New Zealand by retailers who are supplying gas to consumers, which may result in some consistency issues.

Nonetheless it demonstrates:

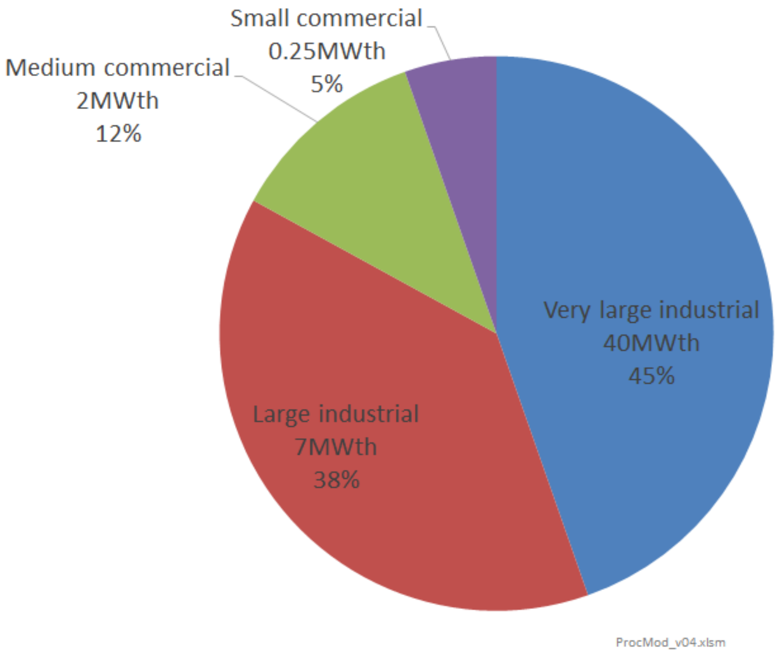
- steadily increasing demand until 2004
- a decline in gas use in the five years after 2004, coinciding with an increase in price[39]
- in the case of forestry, the demand that was lost has not returned, as wood and paper processors have generally replaced gas with onsite waste biomass
- a significant increase in food processing in 2010, largely as a result of growth in the dairy industry.

Within the industrial sector, gas is mostly used in intermediate and high process heat applications (e.g. using a boiler to produce steam, or in furnaces), with some demand for manufacturing of iron & steel. Some of these applications have few practical alternatives to gas. However, the primary application is for intermediate temperature boilers (between 100 and 300°C).

Although there are a wide range of boiler sizes, Figure 42 shows that energy consumption is dominated by the relatively small number of large and very-large industrial boilers.

[39] As is detailed further in section 2.1, this increase in gas price reflected a temporary tightening of New Zealand's reserves position following the re-determination downwards of remaining gas reserves for the Maui field which, at the time, was the principal source of gas for New Zealand.

Figure 41: Proportion of energy provided by different-sized commercial & industrial boilers



Source: MBIE analysis of EECA data

Figure 42 and Figure 43 below, highlight the economics of gas relative to alternative fuels for 'very large' and 'large' boilers[40] compared to other fuel options.[41] This analysis shows the lifetime costs of four fuel options on a $ per gigajoule of useful heat basis. It is shown separately for a new boiler application—in which upfront capital costs would be incurred, and existing applications where these costs are sunk, but where boiler efficiency and operating costs are likely to be worse than for a new boiler.

[40] 'Very large' boilers are of a size which would likely be connected to the gas transmission network, whereas 'large' boilers would likely be connected to a gas distribution network.
[41] We note there are other potential energy sources including liquid fuels and geothermal. The commodity cost of liquid fuels (LPG, diesel, and fuel oil) is likely to remain materially higher than gas costs for the foreseeable future, and geothermal is only an option in some very specific locations. We therefore haven't included these in the graph.

Figure 42: Process heat economics for very large industrial boilers

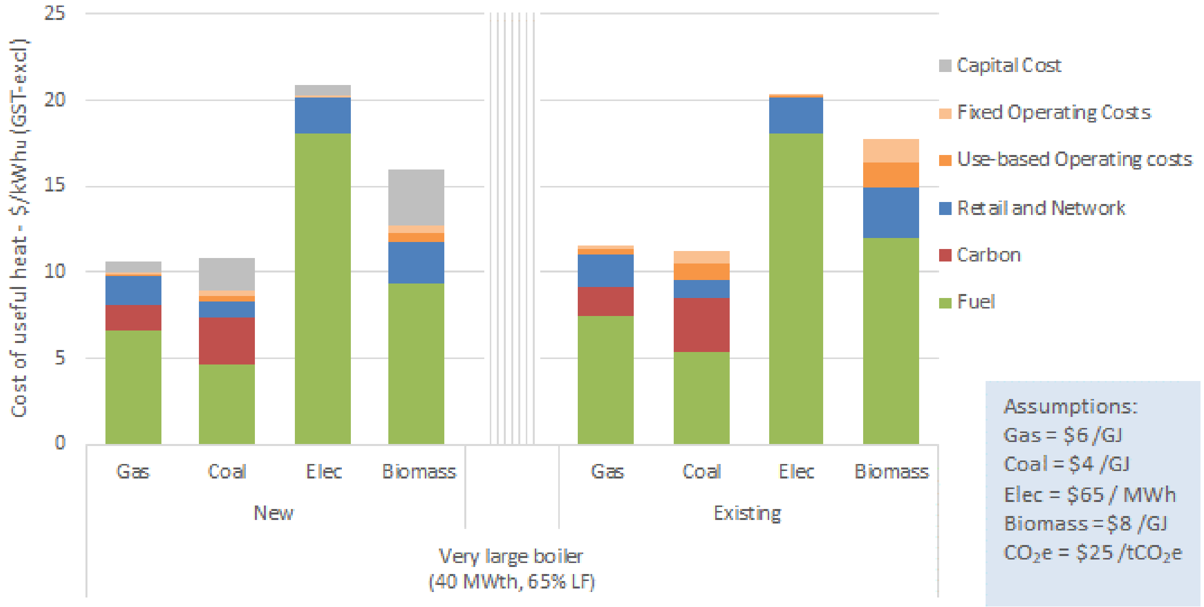


Figure 43: Process heat economics for large industrial boilers

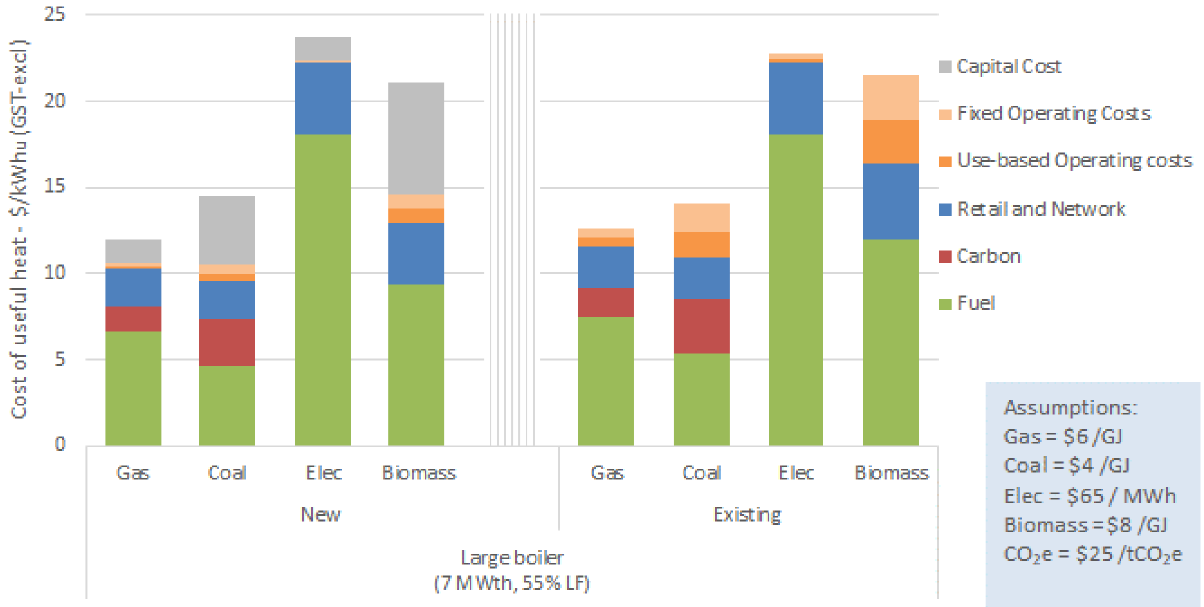
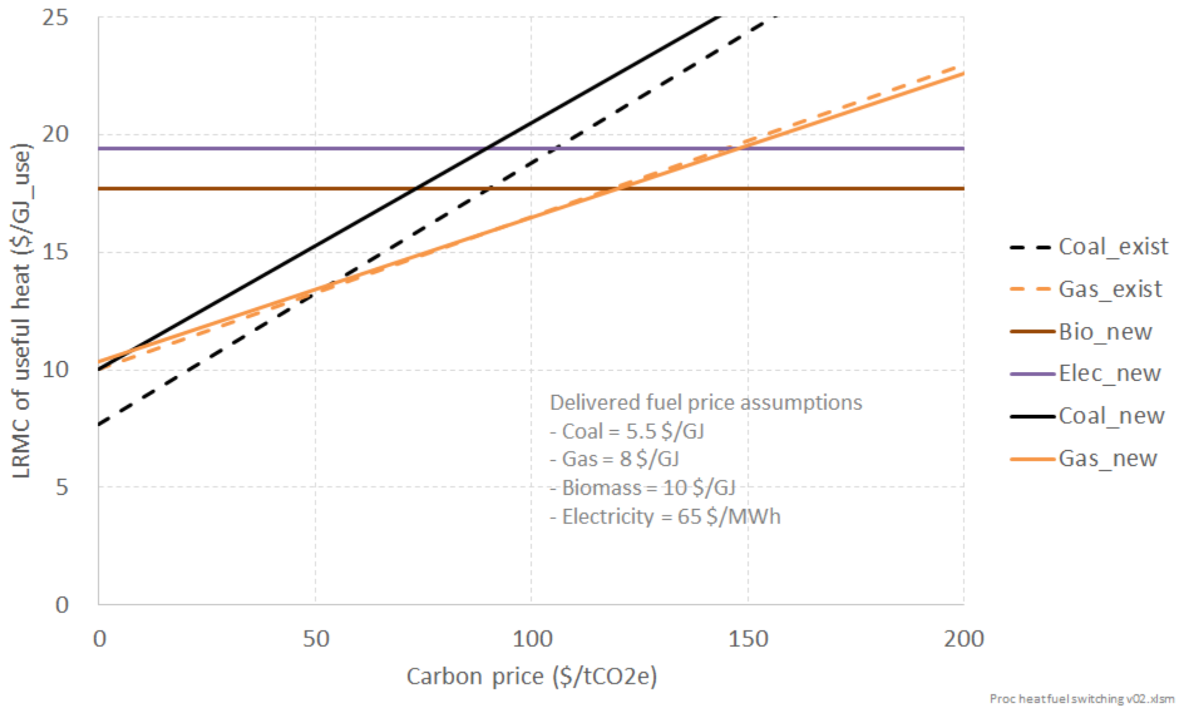


Figure 44 below develops this further by showing how the cost of providing industrial process heat for the different options varies with carbon price.

Figure 44: Illustration of variation in industrial process heat costs with carbon price



There can be significant variation in the cost of options due to site specifics – e.g. biomass and coal costs can vary significantly with distance from the mine/forestry processing facility, and the specific type of product. Likewise, electricity costs can vary if upgraded network infrastructure is required to draw a high electric load. Further different shaped demand profiles can deliver different electricity costs.[42] Nonetheless, this analysis highlights the general trends for the relative economics of the different fuel options.

This shows that, unlike for residential consumers, fuel and carbon costs are the main components of costs of delivering useful heat. This is because industrial boilers have much higher load factors (50-60%, compared to 3-4% for a domestic heater), so the fixed capital and operational costs are spread over a much greater volume of useful heat. The capital costs of industrial boilers also have economies of scale.

Figure 42 shows that gas has comparatively low fuel costs—second only to coal. However, carbon prices affect coal around twice as much as gas, so coal's fuel-cost advantage is quickly eroded.

We consider gas' primary competition going forward will be biomass and electricity. We note that coal is already losing out to electricity in the South Island (where gas is not currently an option), with two dairy processors deciding on electric boilers rather than coal boilers for new investments at a couple of sites.

For baseload consumption, the carbon component of electricity is virtually zero, as it can be met by new renewables. However, electricity has high fuel costs, so gas has a reasonable buffer before it suffers from competition from electric boilers. Our analysis suggests that at current electricity prices, fuel switching from gas to electricity would start when the price to use gas reached around $11 /GJ.

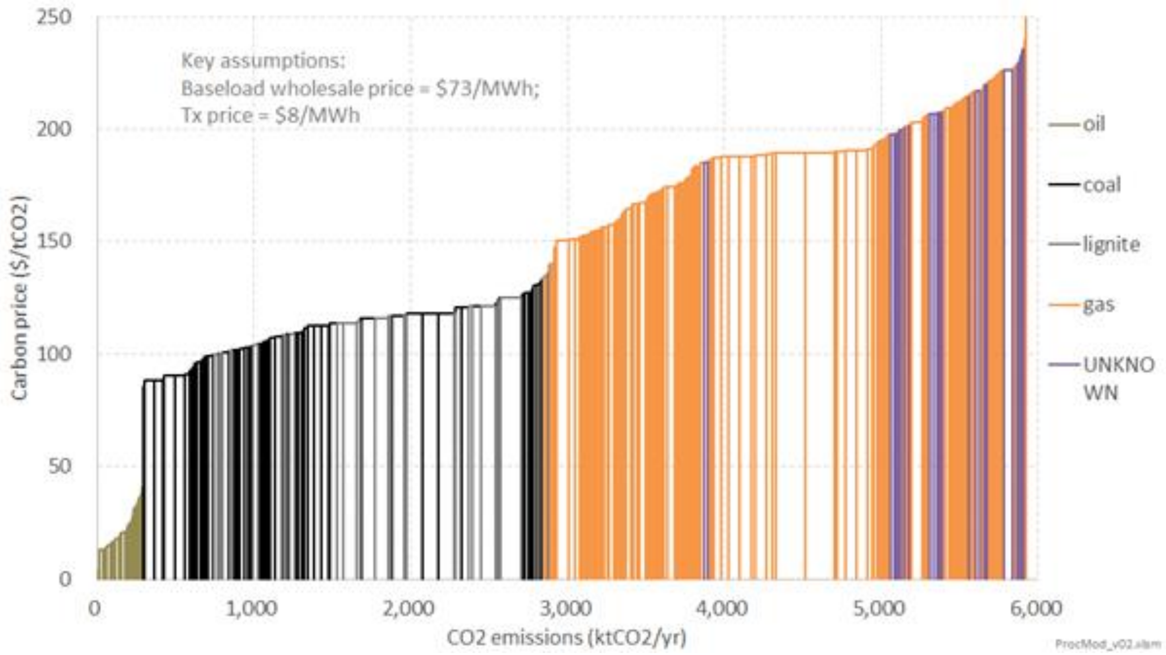
However, there is a wide range of prices at which fuel switching will become economic for industrial users. The price will depend on site-specific factors such as the size and age of the boiler, whether it

[42] For this analysis we have used a dairy processing heat profile, whose counter-seasonal shape of demand results in a demand-weighted wholesale electricity cost which tends to be lower than for a simple baseload demand shape.

would connect to the electricity transmission or distribution network, and whether electricity network upgrades would be necessary for it to connect. We estimate that for some applications, gas would remain competitive through to prices of over $15 /GJ.

At current gas fuel prices of around $6, this price range equates to a carbon price of around $130-200 /t$CO_2$e. This is shown by Figure 45, which shows our estimate of the carbon price necessary for boilers around the country to switch to electricity, given current fuel prices.[43]

Figure 45: Marginal abatement curve for switching to electricity for existing boilers



Source: Concept analysis using EECA data

The timing of asset replacement decisions could significantly impact gas demand for industrial process heat. Any investment decisions will be made with a view of future gas and carbon prices, rather than prevailing prices at the time of the decision.

Specifically:

- When existing industrial gas users' boilers need replacing the sunk cost nature of existing boilers will not be an advantage relative to lower-carbon options.
- There are improving energy efficiency options that have the potential to yield significant fuel savings for industrial gas users (e.g. 30% savings). These could potentially be implemented now. However, if that investment would not integrate with a boiler using a different fuel, then the industrial consumer may choose to wait until the boiler needs replacing.

[43] Note, this graph is for all New Zealand boilers. There is uncertainty over some factors in this analysis, including actual coal prices paid in the South Island, or the age and cost of existing boilers. Nonetheless, we believe it is a reasonable estimate of the relative economics of fuel switching to electricity for large industrial process heat

- There is some remaining potential for coal to switch to gas in the North Island, which would likely be economic now. However, this would require a complex evaluation based on expected future gas and carbon prices.[44]

As with residential and commercial gas demand, gas and electricity network pricing will also be important for industrial users. For example, electricity transmission pricing options that allocate a greater proportion of sunk network costs on a beneficiaries pays basis will tend to increase electricity transmission prices in the North Island relative to the South Island. Given the relative geographical disposition of industrial coal and gas consumption, this would tend to make coal-to-electricity switching more likely, but gas-to-electricity switching less likely.

Lastly, we consider that possible future developments in carbon capture and storage (CCS) are unlikely to materially change the above conclusions. While technology is improving for separating CO_2 out of the exhaust stream of energy users (albeit with significant economies of scale meaning that such options are currently only practicable for the largest energy users around the world) , the biggest obstacle to overcome in New Zealand is in relation to options for storing the CO_2 once it has been extracted.

The only current storage options which appear close to being cost effective around the world are sequestering the CO_2 in underground formations – either salt caverns or depleted oil & gas reservoirs. As New Zealand doesn't have salt caverns, the only options appear to be depleted oil and gas reservoirs in the Taranaki region. This is likely to limit the potential for CCS to large-scale petrochemical or energy users in the Taranaki region, as the economics of building pipelines to transport CO_2 from distant locations to Taranaki are likely to be extremely challenging relative to fuel-switching from gas to biomass or electricity.[45]

6.4 Power generation

In 2017, 60 PJ of gas were used to generate 6,600 GWh of electricity, which was 15 per cent of total generation. The remaining 85 per cent was primarily from renewable sources—including hydro (58 per cent), wind (5 per cent) and geothermal (17 per cent)—plus a small amount of coal (3 per cent).[46]

Figure 46 (a) shows that from 1990 to the mid 2000's, thermal generation (gas and coal) expanded to meet growth in electricity demand. During this time, four new combined-cycle gas turbine (CCGT) power stations were built.

However, from the late 2000s to the present day, this growth in thermal generation was reversed—thermal output has reduced by around 50 per cent over the last decade. Figure 46 (a) shows that thermal generation's contribution varies each year (largely to balance out hydro variability) but has decreased overall in place of generation from geothermal and wind generation. This is a result of demand for electricity being flat, the introduction of a carbon price making thermal generation more

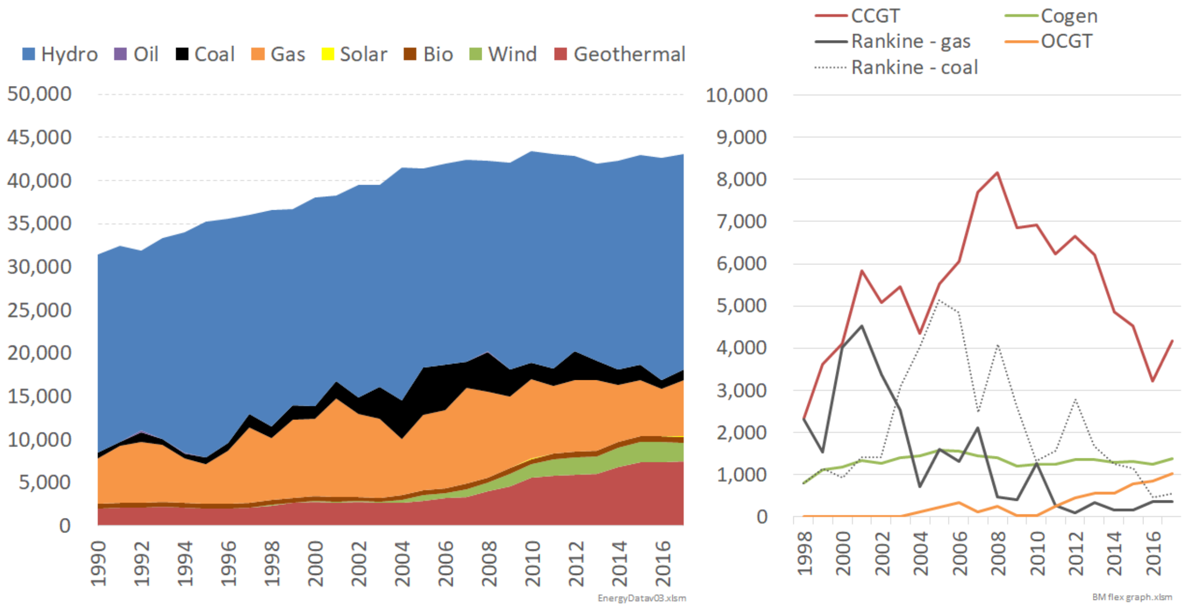
[44] Although in principle these could be potential sources of increased demand for gas, through switching away from coal to gas, Figure 44 highlights that this will only happen if the dairy site owner has confidence that carbon prices (and gas prices) will stay in the zone where gas is the cheapest option, and not move to higher levels where biomass or electricity would be cheaper.

[45] It should be noted that this conclusion is based on past high-level analysis on the economics of building new natural gas transmission pipelines to transport gas if it were discovered in a new region of New Zealand (e.g. the East Cape, or the South Island) to join up with the current Taranaki-centric gas market. This past analysis concluded it would not be economic to build such pipelines relative to developing petrochemical or LNG export facilities in the location where the gas was discovered.
However, without having specifically examined the potential economics of developing CO_2 pipelines, we are unable to definitively conclude that non-Taranaki-located CCS is likely to be uneconomic.

[46] Ref MBIE data

expensive, and the costs of new renewables decreasing, allowing them to out-compete thermal generation for some generation duties.

Figure 46(a) and (b): Historical generation by fuel source and thermal technology (GWh)



Source: MBIE and Electricity Authority EMI

Figure 46(b) highlights that the reduced thermal generation has been from CCGTs and the Huntly Rankines (which use both coal and gas). Two CCGTs retired in 2015 because of reduced utilisation—Otahuhu B (400 megawatts) and Southdown (175 megawatts), both in Auckland. Genesis Energy also decommissioned one of its four 250 MW Rankine units in 2012 and put another into long-term storage in 2015 (although more recently it has been exploring its ability to operate all three units to meet possible future winter capacity shortfalls).

Conversely though, generation by open cycle gas turbines (OCGTs) has increased. Two OCGTs have been commissioned since 2008, adding 300 MW of capacity. Nova Energy also recently announced it will progress its Junction Road power station in Taranaki, which will have two 50 MW units and is expected to be commissioned by 2020.

Looking forward, after a period of 8-10 years with little or no electricity demand growth, New Zealand is likely to see a resumption of significant electricity demand growth. This is likely to be principally driven by uptake of electric vehicles and the gradual electrification of New Zealand's industrial process heat (especially coal-based). For example, in its recent Te Mauri Hiko–Energy Futures publication, Transpower projects demand to more than double by 2050, from current levels of 40 TWh to 88 TWh.[47]

Our own modelling suggests similar (albeit not as fast) levels of demand growth—although with outcomes sensitive to factors such as future carbon and oil prices, technology costs (particularly the cost of batteries), and levels of population and GDP growth.[48]

This significant increase in demand begs the question of where gas-fired generation will fit into this future. Will it meet some of this increase in demand, or will some of the low-carbon drivers behind

---

[47] Te Mauri Hiko–Energy Futures, Transpower White Paper 2018, base case scenario.

[48] For example, our modelling for the Productivity Commission's work on a Low-emission economy projects electricity demand rising to between 58 and 78 TWh by 2050, depending on variations in such input assumptions.

the electrification of parts of the New Zealand economy also cause further reduction in gas-fired generation?

The following sections explore these issues, distinguishing between the outcomes for baseload generation (i.e. generation that operates 24/7) versus outcomes for plant that is used less frequently to provide 'peaking' generation – i.e. to provide seasonal and/or dry-year support).

6.4.1 Baseload gas generation is price sensitive and exposed to competition

Some gas-fired generation operates on a fairly consistent basis over time—i.e. 'baseload'. Some of this is from the cogeneration plant at the Glenbrook steel mill and some large dairy processing plant. However, the majority is from the two remaining CCGTs—e3p at Huntly (400 MW) and TCC in Taranaki (380 MW).

Only e3p currently operates close to a near-continuous basis, and in 2017, it consumed around 22 PJ of gas. However, our analysis suggests that e3p would be likely to scale back operation in a very wet year—i.e. some proportion of e3p's output is performing a hydro-firming role.

TCC historically has operated in a baseload role, but due to displacement by renewables in recent years, it has tended to run at high output for just a few days or weeks at a time, mainly in winter. It used around 9 petajoules of gas in 2017.

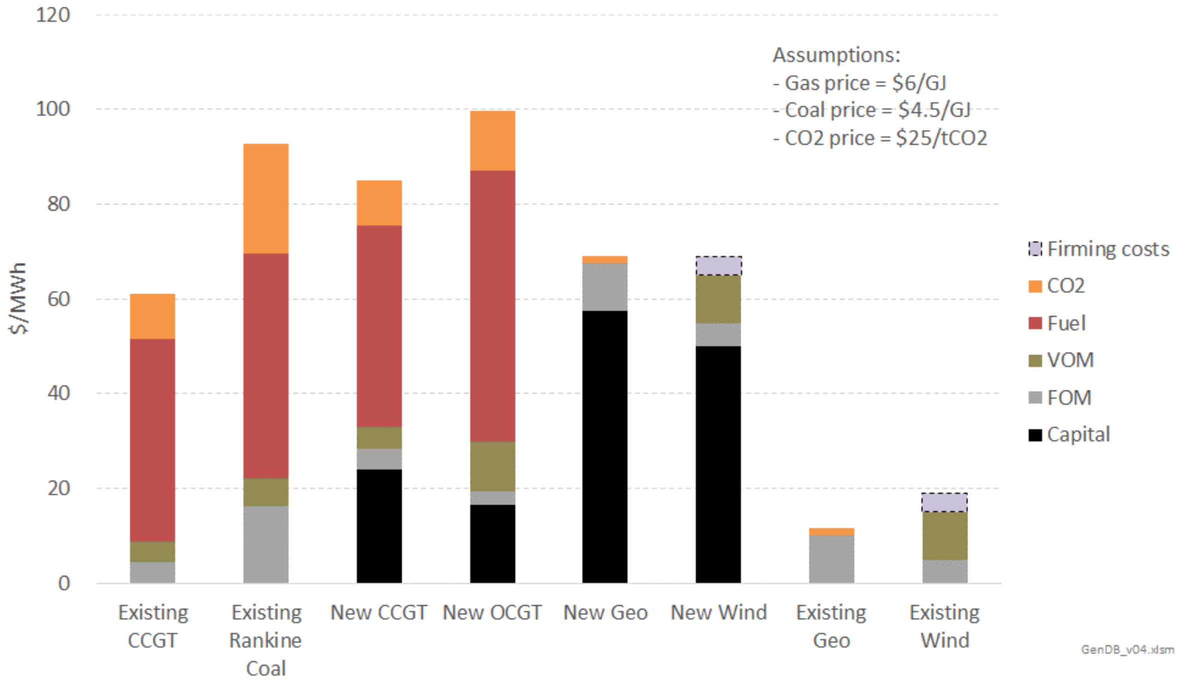
Looking forward, if electricity demand growth picks up, a significant proportion of this growth could be met by TCC progressively increasing its output until it moves back into a baseload mode of operation. However, if new renewable stations are built whose output is roughly equal to increased demand growth TCC would not increase its output.

Further, if new renewable stations are built at a rate that is *greater* than demand growth, e3p will start to be displaced from baseload operation.

Currently the two main cost-effective options for new renewables are geothermal and wind.[49] Figure 47 shows the breakdown of costs of these options relative to gas and coal-fired generation options, using an assumption that the cost of new wind and geothermal are approximately $75 /MWh.

[49] Utility-scale solar is currently significantly more expensive than geothermal and wind in New Zealand – and rooftop solar even more so. However, current consumer electricity tariffs are distorting price-signals to consumers, with the result that rooftop solar is effectively being 'paid' significantly more than it is worth. This is largely due to consumer tariffs recovering the majority of network and retail-cost-to-serve costs via a $/kWh variable charge that solar can help consumers avoid, even though such costs do not vary with consumer consumption. Consideration of these issues is beyond the scope of this study. However, the initial Electricity Price Review report has highlighted that consumer tariff reform is a key issue to be addressed – in part to address these types of outcomes.

Figure 47: Cost breakdown of different types of generation to provide baseload power[50]



As can be seen, based on these cost estimates it would not be economic to build new geothermal or wind to displace existing CCGTs from baseload operation.

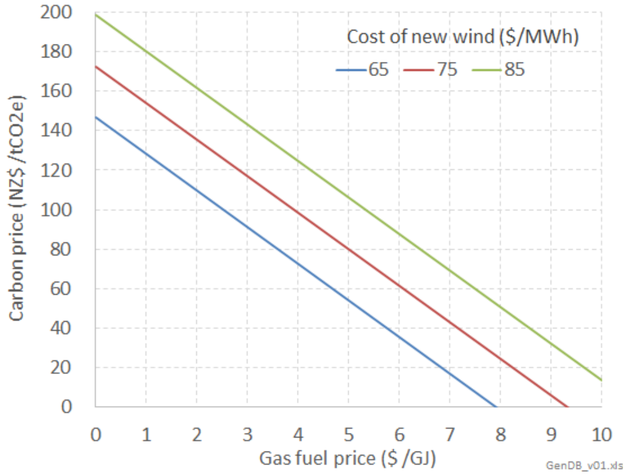
However, if the cost of using gas were to rise, or the cost of geothermal or wind were to fall, it could become economic to build geothermal or wind to displace existing CCGTs from baseload operation. As shown in the below figure, our analysis suggests that if the long-run marginal cost of new wind is $65/MWh (including firming costs), it starts to become economic to build wind to displace CCGTs if it costs $7.80 /GJ or more to use gas. At current gas fuel prices of $6 /GJ, this would occur at a carbon price of $35 /t$CO_2$e.

[50] Capital costs represent the annualised capital recovery requirements for the initial investment in a new power station. Such costs are not considered for an existing power station.
Fixed operating costs are the fixed costs incurred each year from keeping the plant maintained and operational.
Variable operating & maintenance costs are the non-fuel operating and maintenance costs driven by MWh of operation.

However, this threshold price could drop over time due to a number of factors:

- the cost of building new wind schemes has been falling significantly over the past decade due to global technological improvements in wind and increased manufacturing scale economies. The IEA expects global average onshore wind generation costs to decline by almost 15 per cent by 2022.[51]
- The costs of keeping e3p and TCC operational will start to rise over time as they get older and require increased operation and maintenance costs – i.e. they will not be able to carry on operating forever. This will result in gradual increases in the fixed and variable operating cost components for CCGTs.

Figure 48: carbon and gas fuel prices for economic displacement of CCGTs



Source: Concept analysis

Further, as Figure 47 also illustrates, if and when a CCGT retires, it will not be cost-effective to replace it with a new CCGT even if carbon prices are zero. This is because the costs of new baseload renewables in New Zealand have fallen to the point that they are cost-competitive with new CCGTs – even without a cost of carbon.

Thus, looking forward, it is likely that the CCGTs will exit from baseload modes of operation at some point in the future due to a combination of rising gas and carbon prices and falling wind costs.

The 2016 Supply and Demand study contemplated the potential for the exit of the Tiwai aluminium smelter to hasten the retirement of the CCGTs. The smelter had been struggling financially. It contributes around 14 per cent of New Zealand's total demand for electricity, and the loss of so much demand would likely see the CCGTs retire sympathetically.

However, we consider the exit of Tiwai is much less likely than it was in 2016 because:

- the economics of aluminium production in New Zealand have improved, with a drop in the New Zealand exchange rate and increase in aluminium prices. Illustrative of its improved position, the smelter is restarting production from its fourth potline, which has been idle since April 2012.
- Tiwai is well positioned in a world focussed on carbon, because New Zealand's largely renewable electricity makes Tiwai much less exposed to carbon prices than many of its international competitors. Aluminium may also see heightened demand globally, because in many applications it can be a substitute for steel, which has higher carbon implications.

6.4.2 Flexible generation is robust

While the previous sub-section identifies that it is likely to be a situation of 'when not if' baseload gas-fired generation exits the New Zealand market, this is not necessarily the case for the gas-fired generation operating in 'peaking' mode.

There is a need for generation that can offset changes in demand and supply that occur over several timeframes. Specifically, we need generation that can operate flexibly:

[51] https://www.iea.org/renewables/

* over the course of a day and week, offsetting variations in demand and short-term variations in the output of other renewable generation such as wind and solar.
* across the seasons, reflecting that demand for electricity is higher in winter than in summer, and hydro inflows typically reduce in winter with rain being stored as snow.
* from year-to-year, offsetting long-term variation in renewable generation as a result of annual rainfall and wind conditions, with dry years tending to be correlated with 'calm' years.

Much of the required flexibility is currently met by 'sculpting' hydro generation – storing water at times of relative surplus (i.e. periods of low demand) and releasing at times of relative scarcity (i.e. periods of high demand). Hydro meets a very large proportion of the demand for within-day and seasonal flexible generation.

However, hydro can't meet all of the required variation given its maximum generation capacity, limited reservoir storage capacity, and need to meet minimum flow rates on rivers under Resource Management Act consents. Furthermore, by definition, hydro generation cannot meet the need for year-to-year variation that it causes through its susceptibility to drought.

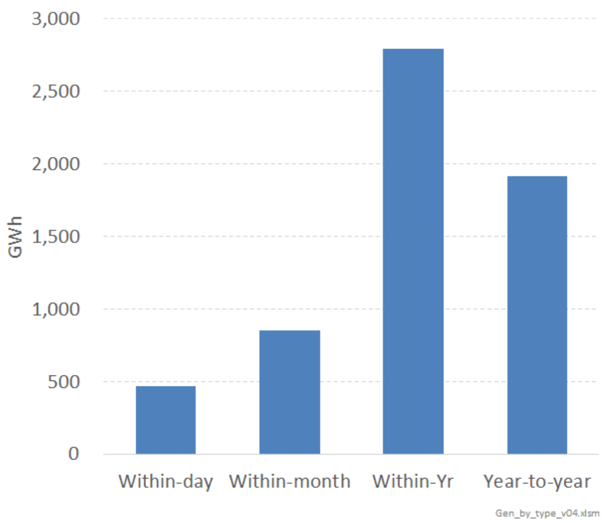
This gives rise to a 'residual demand' for non-hydro generation to operate flexibly.

Our modelling of the demand for non-hydro peaking generation splits such demand into different timeframes. i.e. how much is due to meeting the requirements for: within-day variations, seasonal variation, year-to-year variations etc. The results of our analysis on this is shown in the below figure.

This shows that the biggest drivers of the demand for flexible GWh are

* Within-year (a.k.a. seasonal) flexibility – i.e. operating more in winter and less in summer
* Year-to-year flexibility. This is primarily to provide hydro firming – i.e. increasing output during 'dry' years and scaling back output during 'wet' years. Increased uptake of wind may increase this year-to-year flexibility requirement as there has been shown to be a positive correlation between wind and hydro for much of New Zealand's wind resource. i.e. dry years are more likely to be 'calm' years.

Figure 49: Demand for flexible non-hydro generation over different time-frames



Source: Concept analysis

The options for meeting this demand from measures other than gas generation are:

* Coal-fired generation
* New hydro schemes
* Increasing the sculpting of existing hydro schemes to make them peakier
* Batteries
* Demand response
* Over-building renewables and using spill as the flexibility resource

The main options to meet flexible energy requirements are over-building renewables

Our analysis suggests that hydro, batteries and demand-response are unlikely to be cost-effective to provide the flexible peaking GWh that are currently provided by thermal generation for seasonal and dry-year duties.

The only other main alternative to thermal generation is therefore over-building renewables and using spill as the flexible resource. For example, to meet the demand for seasonal flexibility, this option would involve building a wind or geothermal station whose output was only required during the winter months.

This is a relatively expensive option due to the capital intensity of renewables. Thus, building a windfarm that is only required for a third of the time will increase the capital and fixed operating cost recovery element of its generation three-fold.[52]

In contrast, as illustrated by Figure 47 previously, the capital and fixed operating cost recovery element of a thermal station is a much smaller proportion of its operating costs. Increasing these elements three-fold will be a lot lower cost than increasing the capital and fixed operating cost recovery elements for a new renewable station – particularly if the thermal station is already built and therefore the capital recovery element is zero.

That said, if the cost of carbon is high enough, the advantage of lower capital and fixed operating cost recovery of thermal plant will be outweighed by the higher carbon costs.

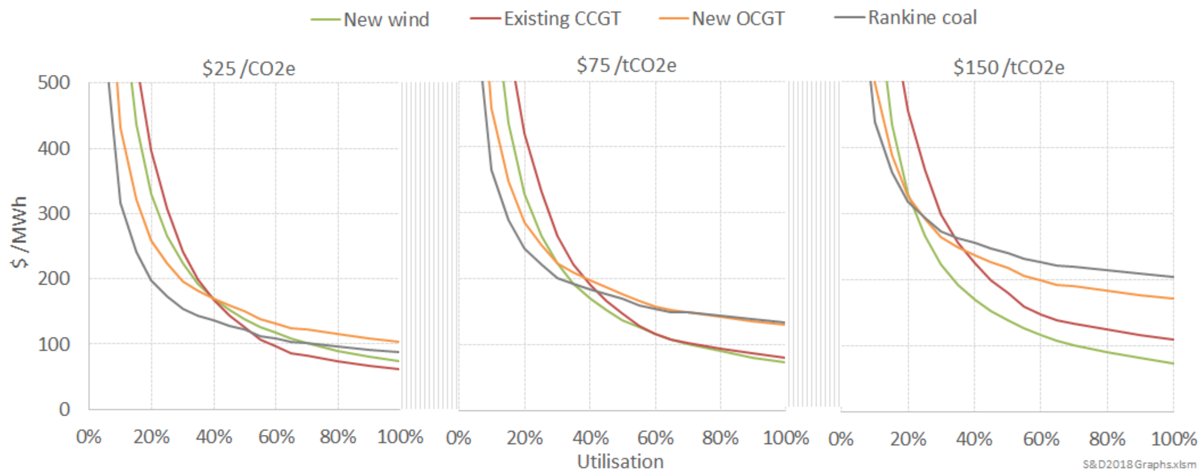
Further, the cost of providing gas and coal increases at progressively lower capacity factors. For example, providing gas that is only required for 10% of the time can cost twice as much as providing gas for baseload operation. In contrast the cost of providing low capacity factor coal is a lot less than providing low capacity factor gas. This is due to the relatively low costs of maintaining a coal stockpile, and the ability to access international coal with three-to-four-month notice periods—something that is of no use to meet seasonal requirements but is very useful to meet the year-to-year requirements for hydro firming.

The above factors result in relatively complex dynamics as to the relative cost of options to provide lower-capacity factor generation.

This is illustrated by Figure 50 which shows how the cost of providing energy at different capacity factors varies between types of plant and varies according to the cost of carbon.

[52] Some commentators have suggested that overbuilding renewables could be combined with the development of green hydrogen production - i.e. making hydrogen from water using electrolysis powered by this surplus renewable electricity. However, because the pattern of surplus and scarcity in New Zealand is predominantly a seasonal one overlaid with year-to-year variation (due to dry/wet years), this requires the hydrogen to be stored for long periods of time in order to achieve an average low cost of hydrogen production. Our analysis indicates that this, coupled with the significant energy losses and additional capital costs associated with the production and use of hydrogen, means that hydrogen is uneconomic relative to alternative low-carbon options for providing transport, heat and peaking electricity generation services. For more detail, see our Hydrogen study published here: www.concept.co.nz/publications

Figure 50: Cost of generation for different capacity factors and carbon prices



At current carbon prices, it is not cost-effective to build renewables to displace existing CCGTs, and Rankine coal is the most cost-effective option for lower capacity factor duties.

At $75/tCO_2e$ it could be cost-effective to over-build renewables to displace CCGTs up to approximately 65 per cent capacity factor.

At higher carbon prices the level of renewables over-build that is cost-effective increases. However, even at $150 /tCO_2e$ it is not cost-effective to completely replace thermal plant with renewables for low capacity factor duties.

To make it even more complicated, the effective cost of variable renewables (wind and solar) will increase as the proportion of generation from variable renewables increases. This is because increasing amounts of back-up resources will be required to provide firming generation for periods when the wind is not blowing or the sun not shining.

If wind is the main new-build option to meet the growth in baseload demand (e.g. to meet the demand for EV recharging), this will tend to increase the effective cost of additional wind and reduce the extent to which it will be cost-effective to over-build renewables.

Summary

In conclusion, it is likely that baseload CCGT generation will exit at some point in the next decade or so. Further, baseload gas-fired cogeneration will also likely exit at some point in the future – although later than baseload CCGT generation.

The timing of when such plant will exit will depend on the rate of cost reduction of new renewables and increases in carbon prices. Further, for cogeneration at the Glenbrook steel mill, the relative economics of New Zealand steel production compared with the rest of the world – which in part depends on the extent to which overseas steel producers face a cost of carbon.

However, it seems likely that some gas-fired generation will continue to be required to meet the demand for flexible energy for the foreseeable future, particularly to meet the requirements for seasonal and dry-year flexibility.

This conclusion is also supported by Transpower in its recent 'Te Mauri Hiko - Energy Futures" report. It stated:

> *"Given the unique characteristics of New Zealand's energy system, managing winter and dry-year energy shortages is one of the most fundamental issues addressed in this report… Several potential technical solutions for managing New Zealand's unique winter and dry-year energy issue have been identified but none appears definitely feasible and economically attractive… Only under the 'Peakers Permitted' scenario is New Zealand's exposure to supply shortages during winters and dry years eliminated. Estimates indicate that by 2050, even in a 'Peakers Permitted' scenario, if all existing thermal peakers were retained, New Zealand would need to build six or seven more (~400MW) gas peaker plants to meet the full shortage estimated in a dry year."*[53]

Therefore, it is likely that gas generation will continue to be the most cost-effective option to meet peak demand, higher winter demand, and as cover for hydro during dry years.

Using policy interventions to hasten the exit of fossil generation from these peaking roles would require uptake of higher-cost substitutes. This would increase electricity prices for consumers, and may not be the most effective approach for decarbonising the New Zealand economy.

New Zealand's highly renewable electricity is a potential alternative energy option for many applications—specifically transport and coal-based process heat. Electrifying these sectors that rely on higher carbon fuels offers much more significant carbon reduction opportunities than removing remnants of gas generation that support renewable generation. Therefore, maximising New Zealand's whole-of-economy greenhouse reductions would likely see some ongoing gas-fired generation.

Furthermore, various commentators identify the potential for this electrification to result in extreme growth in electricity demand over the next few decades. As discussed, Transpower anticipates the potential for demand to double by 2050. It states:[54]

> *"The [base case] scenario estimates that over 60 TWh of new generation will be needed to meet estimated demand growth – and the retirement of some existing power stations, including all thermal power stations – by 2050… To give an idea of the size of this challenge and to reinforce the need for significant investment in New Zealand's energy future, 60 TWh of new generation equates to ~2 TWh per year – roughly equivalent to 4.5 typically sized wind farms with ~ 60 turbines each"*

Such a rate of growth can only amplify the challenges of maintaining a reliable, affordable and environmentally sustainable electricity supply. Balancing all three dimensions of the 'energy trilemma' may require continued gas use for electricity generation.

[53] https://www.transpower.co.nz/sites/default/files/publications/resources/TP%20Energy%20Futures%20-%20Te%20Mauri%20Hiko%2011%20June%2718.pdf

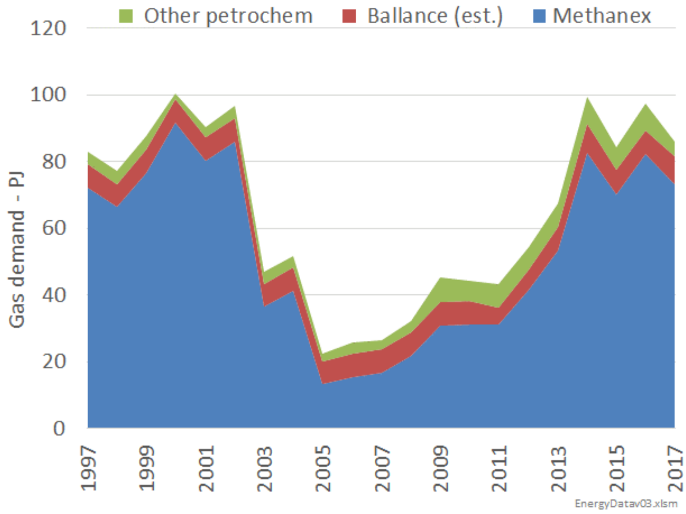
[54] Te Mauri Hiko—Energy Futures, Transpower White Paper 2018

6.5 Petrochemical demand is sensitive to gas prices

Petrochemical production used 86 PJ of gas in 2017—close to half of total demand. The vast bulk of this was from methanol production. Urea production typically accounts for around 7 petajoules, and a handful of small petrochemical producers account for the balance.

Methanol and urea are both commodity products that compete with other international manufacturers. Both industries are currently largely insulated from the effects of the ETS, under the Emissions Intensive and Trade Exposed (EITE) industrial allocation provisions.

Figure 51: Petrochemical production since 1997



Source: Concept analysis using MBIE and Methanex data

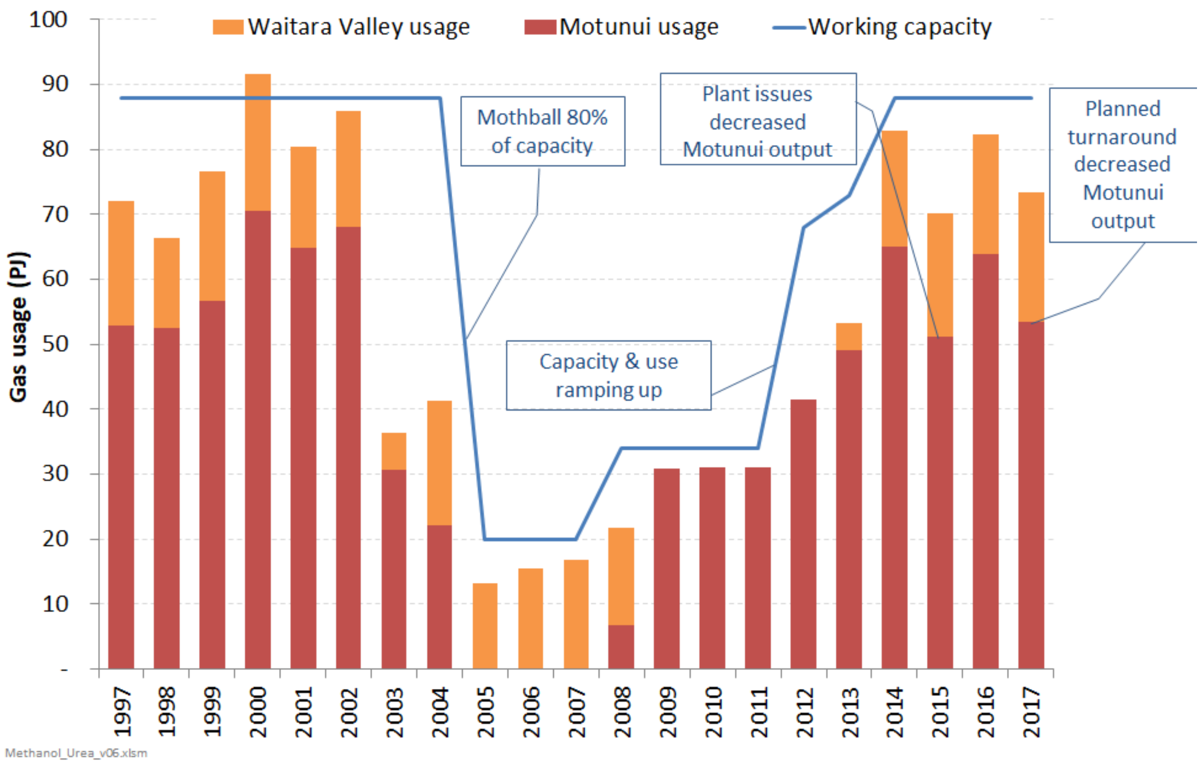
6.5.1 Methanol production in NZ is competitive if there is sufficient supply

In New Zealand, petrochemical gas demand is overwhelmingly associated with methanol production.

Methanex Corporation (Methanex) is the world's largest supplier of methanol and has three methanol producing 'trains' in New Zealand. The Motunui facility comprises two trains, each requiring approximately 34 PJ of gas per year when operating at capacity. The Waitara Valley facility is a single train that requires around 20 PJ of gas per year at full capacity.

Gas makes up the major portion of the variable cost of production for Methanex—around 40 per cent of its gas consumption is for energy, and the remainder is a feedstock for the methanol itself. Methanol production is effectively a means of exporting gas (as methanol) when there is sufficient gas supply in New Zealand to make it economic. When gas supply tightens and prices rise, the trains can be mothballed relatively quickly, and later reinstated. Methanol production has hence varied as New Zealand's gas reserves position has changed over the years. Figure 52 shows how Methanex' three trains have been utilised since 1997.

Figure 52: Methanex consumption and working capacity since 1997



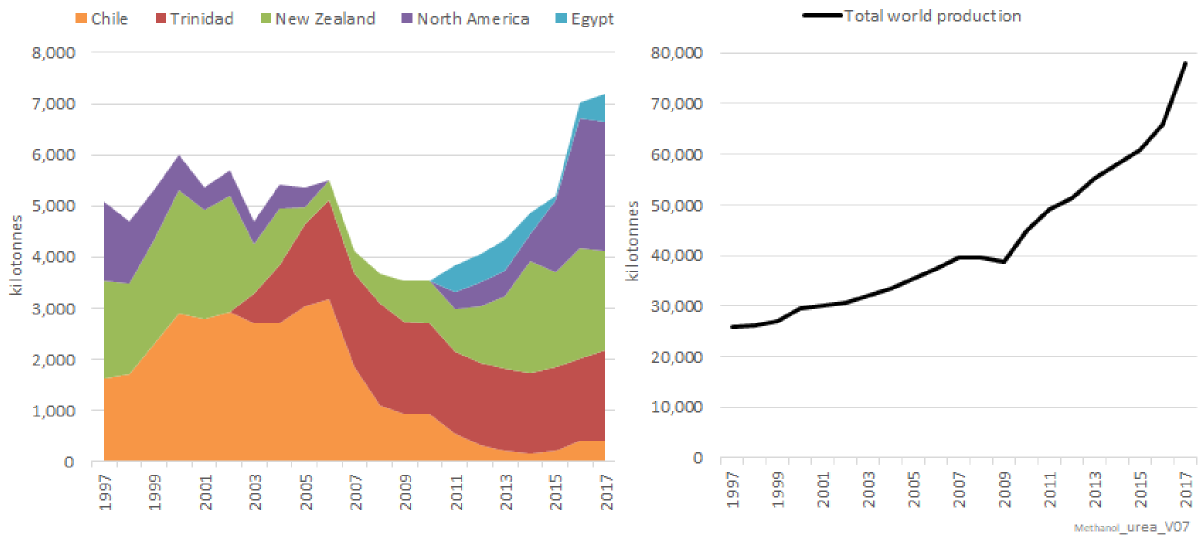
The bulk of methanol produced in New Zealand is exported to customers in Asia. Given this export focus, the level of gas demand for methanol production is primarily driven by the competitiveness of the New Zealand plants relative to other international methanol sources.

Methanex recently announced that it had agreed gas supply contracts to cover "more than half" of its New Zealand operations through to 2029. There is little detail provided about the agreement. However, we understand the contract covers two of the three trains. We also understand some of the supply is contingent on successful field development. The new contract combines with a ten-year contract between Todd and Methanex agreed in 2012, which would imply full production out to 2022. The key question is therefore whether Methanex can contract enough gas at a price that allows its production in New Zealand to remain competitive beyond those dates.

World methanol production to meet world demand has nearly doubled over the last decade. This is shown in Figure 53 (b). Methanex projects that demand will grow by another 17 million tonnes by 2020, potentially outpacing growth in supply. The strong growth is driven primarily by China and is due to expanding methanol applications. It has traditionally been used as a precursor for formaldehyde and acetic acid. Methanol—and other chemicals that can be derived from it—have now also found favour as comparatively clean-burning fuels for ships, vehicles, boilers and generators. It is also projected to see significantly increased use in producing olefins (chemicals used for making plastics). Both applications have high growth potential.

Methanex is currently operating at high utilisation across its multiple locations, reaching record levels of production in 2017. New Zealand accounted for around 27 per cent of its total production, which is shown in Figure 53(a). Utilisation is likely to increase further—Methanex has secured gas for its remaining Chile production to operate at up to 75% of annual capacity through to 2020, and expects gas supply for its Egypt facility to improve. Both plants have been operating below capacity due to gas supply constraints.

Figure 53: (a) and (b): Methanex and world production since 1997



Source: Methanex annual reports. World production excludes integrated methanol-to-olefin production

In this high growth, high utilisation environment, we'd expect the New Zealand plant would primarily need to remain competitive against the cost of the marginal source of new supply.

Currently, the most likely location for new-build (or relocation of existing plant from another part of the world)[55] is the United States—Methanex is already considering expanding its existing production there. The IEA suggests gas prices in the United States are currently equivalent to around $NZ3.75/GJ, but projects them to reach around $NZ5/GJ in 2022 and $NZ6.40/GJ by 2029.[56] The EIA projects similar prices over these timeframes.[57]

We estimate that the sunk capital costs give the New Zealand plant a gas-price buffer of around $0.75-1.50/GJ against relocated plant, or around $3/GJ against completely new plant.

Furthermore, most of the growth in demand comes from China and other Asian markets, which the New Zealand plant are well located to supply. Methanex suggests freight costs from the United States to Asia are around $US80 /tonne.[58] We estimate freight costs from New Zealand to Asia are around $US50/tonne, and that this difference gives the New Zealand-based production a further gas-price advantage of around $NZ1/GJ. In addition, China has imposed tariffs of 25 per cent on methanol from the United States. While likely a transitory issue, the effect of the tariff would largely be to redirect flows of methanol in order to avoid the tariff, potentially adding to the shipping advantage from New Zealand.

Overall, the New Zealand methanol plants are likely to remain competitive beyond 2022 if New Zealand can supply sufficient gas at a price of around $6.70/GJ.

However, carbon prices could reduce Methanex' ability to withstand higher gas prices. It is currently insulated from the ETS because of its EITE industrial allocation, but this may not remain the case in the longer-term. The Ministry for the Environment is currently consulting on changes to the ETS

[55] Over the last fifteen or so years, Methanex has relocated plant between North and South America as the gas markets in these areas have shifted between situations of sustained surplus and scarcity.

[56] Linear interpolation of prices under the new policies scenario. See https://www.iea.org/publications/freepublications/publication/WEO2017Excerpt_Outlook_for_Natural_Gas.pdf

[57] See page 30 of https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf

[58] See Methanex investor presentation, February 2018, slide 15

settings that would see the industrial allocation phased out over time. The specific outcome of that consultation process remains uncertain.

Assessing the extent to which carbon prices would affect methanol production in New Zealand is not straight-forward because:

- It would depend on how fast the industrial allocation is phased out. Methanex currently receives a free allocation for 84 per cent of its total emissions.
- The ETS does not apply a carbon price on exported carbon emissions. Therefore, even if the industrial allocation were phased out, Methanex would not be exposed to carbon prices for the 60 per cent of its gas for which the carbon remains embedded in its exported methanol. Therefore, every \$19 /tCO_2e increase in carbon prices would—assuming no industrial allocation— reduce Methanex' ability to pay for gas by \$0.4/GJ, or increase its costs of production by \$12/tonne.
- Producing methanol in New Zealand will only become less competitive if production in other countries does not also face a carbon price. No other countries currently place a carbon price on methanol production.

  However, if overseas countries do impose a price of carbon on methanol in the future – and that price was the same as the price of carbon in New Zealand – it is likely that the relative competitive position of New Zealand-produced methanol will improve. This is because it will improve its relative position to the large amount of world methanol that is produced from coal which creates 3-4 times the emissions.

  There are also suggestions that the Chinese government may place increasing restrictions on new coal-based methanol capacity additions.

6.5.2 Urea production

The second main petrochemical user of gas in New Zealand is Ballance Agri-Nutrients (Ballance), which produces ammonia urea fertiliser at its facility at Kapuni in Taranaki. Ballance uses around 7 PJ of gas per year to produce 270,000 tonnes of urea fertiliser. It has indicated that it has a gas supply contract that runs to 2020.

The Kapuni plant is largely sunk capital. Ballance has resource consents to run the plant until 2035, and physically, the same plant can operate almost indefinitely, with the main components being periodically replaced. However, the design of the plant means it is less efficient than a modern equivalent. We understand a modern urea plant consumes around 25 per cent less gas for the same output. Trading off these effects, we estimate Ballance has a gas-price advantage of close to \$3 /GJ compared to supply from a new-build plant overseas.[59]

Further, Ballance benefits from being a producer of a commodity for which New Zealand has significant local demand—therefore attracting import pricing. New Zealand currently imports over half of its urea requirements. International freight costs are estimated to be around 10-15 per cent of the delivered price in New Zealand. Domestic production avoids this freight cost, and this advantage equates to a gas-equivalent cost of around NZ\$2/GJ for North Island deliveries (less in the South Island due to domestic shipping costs).

Ballance had been working on plans to modernise its plant, but those plans have recently been shelved because of uncertainty around New Zealand's long-term gas supply and carbon policies.[60] Instead, it is proceeding with a \$35 million refurbishment that will have incremental improvements on its efficiency. While this means it will retain the advantages of being largely sunk capital, its

---

[59] Excluding China

[60] Energy News Article, Hydrogen, low-carbon agriculture hangs in the Balance, 3 July 2018.

higher gas consumption means it will be more sensitive to changes in gas and carbon prices than it otherwise would have been.

Like Methanex, Ballance is currently significantly insulated from carbon prices under the industrial allocation provisions of the ETS. However, unlike Methanex, Ballance's product is used in New Zealand, so it is exposed to carbon prices for its full gas use—including the carbon that remains embodied in the product until use. We therefore anticipate that Ballance has greater sensitivity to future carbon prices. Again, the exact extent of that sensitivity will depend on how quickly the allocation is phased out, and whether there are other changes to the ETS. In this respect, due to current carbon policies, emissions embodied within most imported products (oil being an exception) will not face a carbon price—either here, or in their country of origin. This puts domestic urea at a relative disadvantage to imports, even with carbon price equivalence.

Assuming no industrial allocation, every \$19 /tCO_2e would increase Ballance's cost of gas by \$1 /GJ. Therefore, carbon prices of around \$100 /tCO_2e would see its full advantage compared to imports wiped out – whilst overseas urea producers continue not to face a price of carbon. Higher gas prices would further reduce its ability to withstand carbon prices.

If a mis-match between New Zealand carbon prices and international carbon prices meant that New Zealand closed its urea production facility and imported its full urea requirements, it would see approximately \$115 million spent offshore each year that is currently retained domestically. The impact on greenhouse emissions would depend on whether the replacement world source of urea was more emissions intensive or not.