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# Gas demand and supply projections – 2021 to 2035

May 2021

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# 1 Executive summary

This report was commissioned by Gas Industry Co to update the last bi-annual gas demand and supply study produced in 2019. As with earlier reports, this study examines the longer-term outlook for gas demand and supply. In particular, we consider the outlook to 2035 under a range of scenarios.

Given the unusual conditions experienced in late 2020 and early 2021, this report also examines the gas demand and supply position for the balance of this year and into 2022 in some depth.

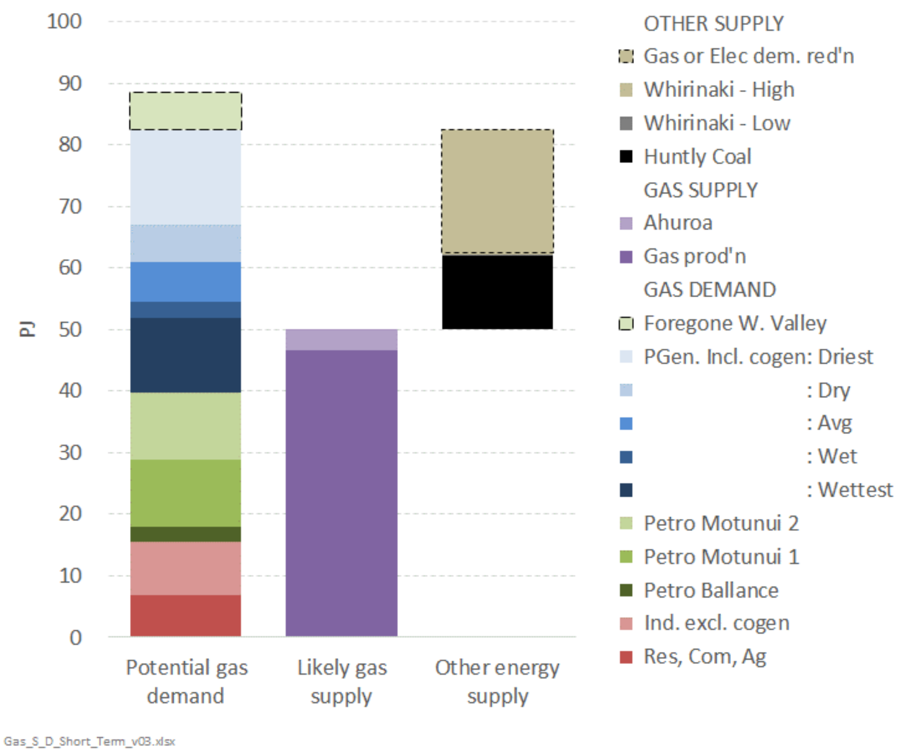
## 1.1 Gas supply for winter 2021 looks very tight

Gas supply is expected to be very tight relative to demand this winter (June to September, inclusive).[1] The tight supply situation is expected to contribute to high wholesale[2] gas and electricity prices. While high wholesale gas prices will hurt users who are not protected by longer term contracts we think the tight supply is unlikely to compromise *physical* gas security for mass market users or for electricity generation.

Figure 1 sets out the key moving parts behind our analysis. The first column shows a stack representing the expected demand for gas in winter 2021. The red and green segments are comprised of relatively predictable residential, commercial, industrial, and petrochemicals demand. These can be regarded as firm sources of demand.[3]

The blue segments show potential demand that is increasingly uncertain because it depends on the need to run gas-fired power stations (including cogeneration). The navy segment shows gas demand in a 'wet' scenario (when need for gas is lowest as there is ample hydro generation). The increasingly lighter blue segments correspond to the rising gas demand as hydro conditions become drier.[4]

*Figure 1: Gas supply and demand balance for June-Sep 2021*




Source: Concept analysis

The top green segment (with the dotted border) is the amount of gas the Waitara Valley methanol plant would have consumed had it not shut down from February 2021 due to lack of firm gas supply.

The second column shows the expected supply available from producing gas fields and the Ahuroa gas storage facility. As shown, this level of supply is unlikely to meet aggregate demand - even if this winter turns out to be very

[1] June to September is typically the most challenging four-month period in a sustained 'dry' event.
[2] Wholesale in this context refers to sales in the spot market and for shorter term contracts.
[3] Firm in the sense that they will take gas, if it is available.
[4] The modelled hydro generation is based on historical inflow sequences from 1980 to 2017, inclusive. The 'Dry' and 'Wet' values correspond to the 10th and 90th percentile levels of hydro generation, respectively.

wet and gas demand for power generation is low. The size of the gap will increase if New Zealand continues to experience dry conditions this winter.

While the chart shows a gap between potential gas demand and expected supply, we do not think this will compromise physical gas reliability to mass market users or electricity generators. This is because:

1) a significant amount of fuel for thermal generation can be provided by sources other than gas – principally coal-fired generation in the Huntly station Rankine units, and (to a much lesser extent) diesel-fired generation at Whirinaki and Huntly unit 6

2) there is the potential for some 'demand diversion' which could temporarily reduce gas and/or electricity demand and preserve supply for higher-value users. This could entail:

   a) some gas users reducing discretionary demand and on-selling some of their entitlement to gas-fired power stations; and/or

   b) some electricity consumers reducing discretionary demand.

Barring any major plant failure in the gas supply chain, we expect sufficient gas to be available to meet demand. However, the tight supply position is likely to contribute to sustained high wholesale gas and electricity prices – reflecting the price needed to induce demand diversion.

## 1.2 Current tight supply reflects two unusual factors

We think the tight conditions for this winter reflect two unusual factors:

- Unexpected major problems at New Zealand's largest gas field, Pohokura. Despite efforts to address these issues, the field production capability is expected to be around 50% of its previous levels this winter.[5] The gas supply outlook was already tight before this reduction occurred, so there was little buffer to cushion the unexpected cut in Pohokura supply.
- The pace of new renewable power station development in recent years had been slowed by uncertainty over the future of the Tiwai aluminium smelter. Absent this factor, more renewable generation would have been onstream for this winter, lowering the demand for thermal generation.[6]

*Figure 2: Supply-demand balance for Winter 2021 plus 'lost' supply*

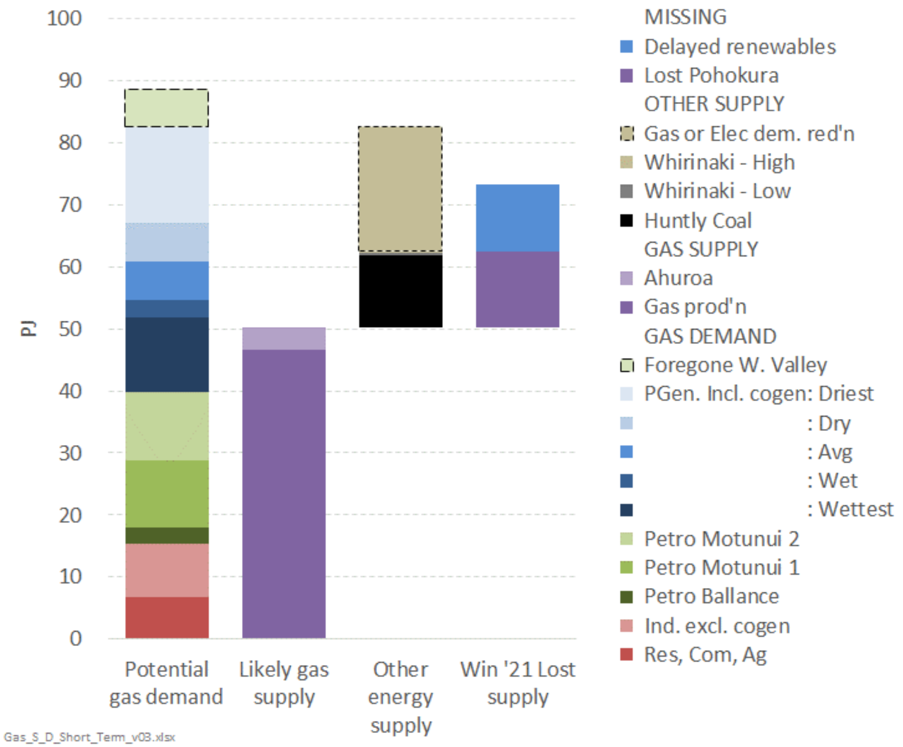



Figure 2 shows the effect of these two factors. The column labelled 'lost supply' shows the estimated impact of the Pohokura supply issues (in purple) and the delays in renewable generation development (in blue).

[5] When fully operational, roughly half of Pohokura's gas comes from offshore wells.

[6] This view is borne out by announcements to proceed with new generation developments by Contact and Meridian shortly after the Tiwai smelter indicated it would continue operation until 2024 (or later).

The combined impact tightens the gas supply demand balance by around 25 PJ in winter. Had these factors not applied, there would have been ample gas supply, including in a dry year.[7]

## 1.3 Outlook for 2022-2035

The tight supply conditions being experienced this year appear likely to continue into 2022. There is a possibility this will be avoided if remedial work at the Pohokura field can be undertaken over the coming summer. However, the timing of this work is uncertain and even if it could be undertaken in the coming summer there is no guarantee it will be successful.

By 2023-2024 there is more confidence that tight conditions will ease. This reflects an expectation that planned work programmes at Kapuni, Kupe, Mangahewa, Maui, and Turangi will have been undertaken by then and will bring more gas to market.[8] In addition, committed new renewable power projects will be on stream, reducing mean gas demand for power generation. Together these factors are projected to lift supply available to other gas users by around 30-45 PJ per year by 2024. If the Tiwai smelter closes at the end of 2024 (the middle case assumption) that will further increase gas available to other users.[9]

Looking out further, there is sufficient gas 'in the ground' to meet mass market, industrial and power generation demand until at least 2035. Out to 2027, that production could come largely from existing reserves but beyond then is likely to require development of contingent resources.[10]

Moreover, there is likely to be sufficient headroom in the supply outlook to support operation of 1-2 methanol units on a steady basis until at least 2030, depending on the rate at which other gas demand recedes and how quickly contingent resources are developed. It is also possible that there would be sufficient gas to operate a third unit, albeit on a less certain basis

Ultimately, the availability of gas for all users depends on producers' willingness to invest more capital in supply-side assets. The investment requirements are potentially very large. Gas Industry Co estimates the industry needs to invest $300-500 million every 3 to 5 years to produce existing reserves and maintain production levels.[11] Some industry experts project even higher requirements. For example, Enerlytica recently projected that over $2 billion would be required during the 2020s to maintain current production levels.[12]

The level of investment will be influenced by wholesale customers' willingness to sign multi-year contracts. Looking forward, we expect mass market and industrial gas customers to continue to be attractive to producers as a source of contracts to underpin investment. Similarly, we expect petrochemical producers (especially for methanol production) to remain as a foundation to underpin investment in reliable gas supply.

The demand segment that we think will have the greatest challenge in securing gas is power generation. In particular, power generators may face increasing difficulty in contracting supply for the portion of their demand that is unpredictable because producers will not invest in supply-side assets without relatively firm sale commitments. The question then becomes how power generators obtain their flexible fuel needs during the transition to 100% renewable electricity – a transition that is expected to last for many years. This challenge will become even greater as Genesis reduces coal use at the Huntly power station.

[7] This is because the sum of the 'missing supply' bars plus the coal bar is sufficient to meet gas demand in even the driest situation. Furthermore, the supply position would likely have been even better than Figure 2 shows as Ahuroa would probably have more gas in storage. If it had been three-quarters full coming into this winter (a more likely 'usual' level) there would be an extra 8.5 PJ gas supply available.

[8] This work is reflected in various company statements and/or production forecasts compiled by MBIE and released in mid-2020.

[9] As we discuss later, Meridian Energy is actively pursuing initiatives to stimulate new sources of electricity demand, such as accelerating the uptake of electric boilers for industrial process heat. Growth in demand from other sources may partially offset the effect of a Tiwai smelter closure.

[10] See section 4.5.3 for more explanation.

[11] Gas Industry Co, Briefing to Incoming Minister, October 2020, page 4.

[12] Enerlytica, NZ Gas presentation to NZ Downstream 2021 Conference, March 2021.

An added challenge in the current environment is that carbon and related policies are yet to be finalised in many areas. Gas sector participants may prefer to delay some decisions until policy is clearer. This could have supply-side implications later in the decade depending on the scale of affected projects and associated lead-times. These points highlight the importance of ensuring a smooth transition, but further exploration of these issues is outside the scope of this report.

# 2 What this report is about

## 2.1 Scope

This report was commissioned by Gas Industry Co to update the last bi-annual gas demand and supply study produced in 2019. As with earlier reports, this study examines the longer-term outlook for gas demand and supply. In particular, we consider the outlook to 2035 under a range of scenarios.

Given the unusual conditions experienced in late 2020 and early 2021, this report also examines the gas demand and supply position for the balance of this year and into 2022 in some depth.

## 2.2 Information sources

Concept has prepared this report based on public information sources, and our own analysis of information from those sources.

We have also benefited from confidential information provided by industry participants and wish to express our thanks for their cooperation.

# 3 Outlook for 2021

## 3.1 Summary – outlook for 2021

Gas supply is expected to be very tight relative to demand this winter (June to September, inclusive).[13] The tight supply situation is expected to contribute to high wholesale[14] gas and electricity prices. While high gas prices will hurt wholesale customers who are not protected by longer term contracts, we think the tight supply situation is unlikely to compromise *physical* gas security for mass market users or for electricity generation.

The very tight conditions for this winter reflect two unusual factors:

- Unexpected major problems at New Zealand's largest gas field - cutting national gas supply by around 15%.
- Ongoing uncertainty about the Tiwai smelter's future slowed the pace of new renewable power station development in 2016-2020. Without this factor, more renewable generation would have been onstream for this winter, lowering the demand for gas-fired generation.

Had these factors not applied, there would have been ample gas supply, including in a dry year.

## 3.2 Methodology focuses on critical winter months

We focus on the balance between gas supply and demand in the June to September months – which we refer to as 'winter'. History shows gas demand is typically highest in these months due to increased space and water heating requirements. In addition, power generation demand for gas generally also peaks in these months because it is colder (lifting power demand) and 'dry years' disproportionally reduce hydro generation in winter.

In the following sections we describe the methodology we have used to prepare gas demand and supply projections for the 2021 winter months.

[13] June to September is typically the most challenging four-month period in a sustained 'dry' event.
[14] Wholesale refers to sales in the spot market and for shorter term contracts.

## 3.3 Gas supply capability for winter 2021

For the major fields, supply estimates are based on discussions with operators. The estimates were provided on a confidential basis, but operators agreed that they could be published in aggregate form. For smaller fields, estimates are based on recent observed performance. We have also used historical and recent OATIS data and other public sources as a cross check on this information.

In aggregate, we estimate average injections into the transmission system to be 398 TJ/day over winter.[15] This is around 100 TJ below the peak level of system production observed in calendar 2020. Most of the decline is due to reduced deliverability at Pohokura. There are also changes in expected deliverability for other fields, but these largely offset each other.

The other main source of gas for the coming winter is the Ahuroa underground gas storage facility. Ahuroa is capable of delivering up to 65 TJ/day into the pipeline system. However, this can only be sustained if the facility has sufficient gas in storage at the outset of winter to maintain that level of withdrawal.

We have used public disclosures to estimate the volume of gas that will be in storage at the beginning of June 2021. We estimate this will be around 3.5 PJ. Based on this volume, the average rate of withdrawal available from Ahuroa over the winter is 30 TJ/day.

Based on the above data, we have calculated the volume of gas available for delivery in the period June to September 2021. The respective estimates are 48.6 PJ from production and 3.5 PJ (net) from Ahuroa storage.

## 3.4 Gas demand for winter 2021

Estimates for each major segment of gas demand have been compiled using the approach set out below.

[15] Note that this figure excludes flows of gas which do not enter the open access transmission system, such as any gas flowing from Kapuni to the cogeneration plant at Whareroa.

### 3.4.1 Gas demand for residential/commercial/agricultural users

Although data on gas consumption by residential, commercial and agricultural users is not available on a monthly basis, pipeline flow data for so-called allocated gates is a reasonable proxy. These allocated gates are the points on the pipeline system that interconnect with distribution networks and typically serve residential, commercial and agricultural users.

Allocated gate data is available for daily flows. Examination of this data shows a distinct seasonal profile which typically peaks in winter. However, the size and timing of the peak can vary from year to year. To compile our demand estimate, we reviewed historical data to identify the period with the highest gas flows over four consecutive months. We considered data from 2018 to 2020 to account for year-to-year variation and avoid reliance on the 2020 data which may have been affected by the aftermath of the Level 4 Covid-19 lockdown. The peak demand was 13.1 PJ recorded in the 4 months to September 2019, although the prior and subsequent years were quite similar.

### 3.4.2 Gas demand for larger industrial users (except petrochemicals)

A similar approach was used for larger industrial users excluding petrochemicals (e.g. food processing, steel making, pulp and paper making).

We reviewed daily gas flow data since 2018 to identify the period with the highest flows. In this case we focussed on the four months beginning in June (rather than any consecutive four months) because demand for these users tends to peak outside the winter period.[16] The peak demand was 6 PJ recorded in the 4 months to September 2019, although the prior year was quite similar. Demand in 2020 was 5.5PJ and may have been affected by Covid-19 lockdown measures.

We reduced this estimate by 0.8 PJ to reflect an assumption that gas use at the Marsden Point refinery will be around 50% of levels recorded prior to 2020. This assumption appears reasonable in light of continuing weak demand for refined product in 2021, especially aviation fuel. The resulting overall demand estimate for industrial users (ex petrochem) is 5.2 PJ for winter 2021.

### 3.4.3 Petrochemical manufacturing

We define petrochemical demand as gas use at the Kapuni ammonia urea plant (owned by Ballance) and the Waitara Valley and Motunui methanol plants (owned by Methanex).

We estimated demand for ammonia urea manufacturing using the same approach as large industrial users. The resulting estimate is 2.5 PJ for winter 2021.

Our approach to projecting Methanex's demand differs from other segments because methanol production levels are typically quite sensitive to gas supply conditions. Indeed, Methanex in February 2021 announced that it would mothball the Waitara Valley plant until further notice due to gas supply constraints.[17] We have projected gas demand in winter 2021 based on two distinct tranches:

- Gas use at the Motunui plants is projected to be up to 178 TJ/day (=peak usage observed in January 2021) multiplied by 122 days (the number of days in June-September). This equates to 21.7 PJ over winter 2021.
- Gas use at the Waitara Valley plant is projected to be zero as per Methanex's announcement in February 2021. However, if the plant were to operate, we expect it would use up to 50 TJ/day which equates to 6.1 PJ over winter 2021.

### 3.4.4 Gas demand for power generation

We separate gas demand for electricity generation into two components – cogeneration and remaining gas demand for power stations. Cogeneration refers to plants in which gas is used to create process heat (for an associated industrial use such as food processing) and to generate electricity.[18] Gas use

[16] This is likely to be due to reduced processing of dairy products in the winter period.
[17] See www.rnz.co.nz/news/business/437055/methanex-to-mothball-waitara-valley-plant-in-taranaki
[18] There are various definitions for cogeneration, and the demarcation between a cogeneration plant and a power station is not always clear.

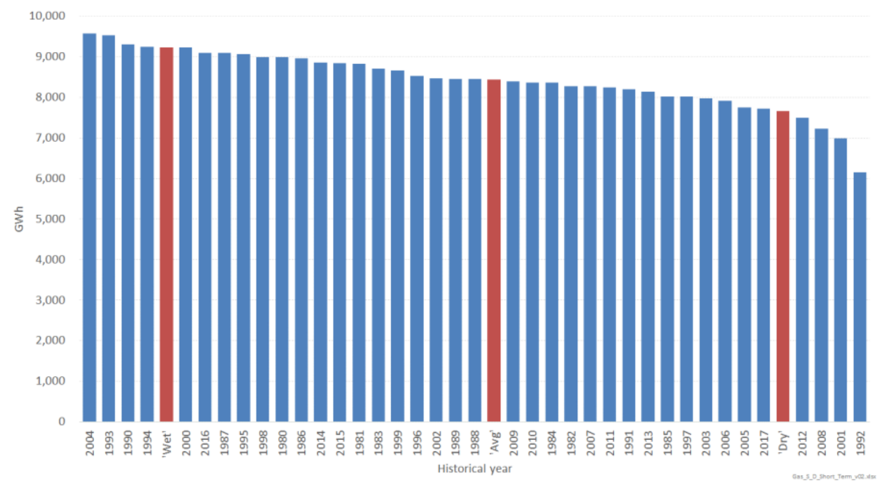
for cogeneration has been fairly stable over time and we have used historical data to forecast cogen gas demand for winter 2021.

The remaining gas demand is more complex to forecast because it is strongly influenced by hydro inflows and storage levels. This means observed demand since 2018 does not provide a robust indicator of the possible gas demand in an extended dry period. A further complicating factor is that some thermal power stations can run on coal or diesel, and higher operation from these fuels will reduce the need for gas-fired generation, all other factors being equal.

We start by using recent electricity sector data to estimate the expected need for 'responsive' generation in winter 2021. This is estimated by taking the difference between projected electricity demand and 'non-responsive' sources of supply such as wind farms (which have intermittent output) and geothermal plants (which tend to run constantly at or close to full output).

The requirement for responsive generation in winter 2021 can be met by hydro- or thermal-power stations. Figure 3 shows the level of winter hydro generation over 38 years. It clearly shows how hydro generation can vary depending upon starting storage and the level of hydro inflows over winter. We consider this dataset to be sufficiently long to capture a representative range of hydro storage and inflow conditions.

***Figure 3: Winter hydro electricity generation***




Source: Concept analysis

For our analysis, the "wettest" scenario reflects the highest level of hydro generation observed in the 38 years. The "wet" hydro scenario reflects the 10$^{th}$ highest percentile of hydro generation. The "mean" hydro scenario uses the average. The "dry" hydro scenario reflects the 10$^{th}$ lowest percentile of hydro generation. The "driest" scenario uses the lowest observed hydro generation.

The balance of New Zealand's responsive generation requirement for winter 2021 will need to be met from thermal power stations. We estimate that around 12 PJ could be met by coal fired generation in Huntly Rankine units. We estimate that approximately 30 GWh of electrical energy can be supplied by the diesel-fired Whirinaki station during winter period. This figure aligns the amount of energy Transpower assumes can be supplied by Whirinaki in its security of supply monitoring,[19] and reflects potential fuel constraints encountered when running Whirinaki at a high output.

[19] See www.transpower.co.nz/system-operator/security-supply/hydro-risk-curves-explanation

## 3.5 Gas supply will be tight for winter 2021

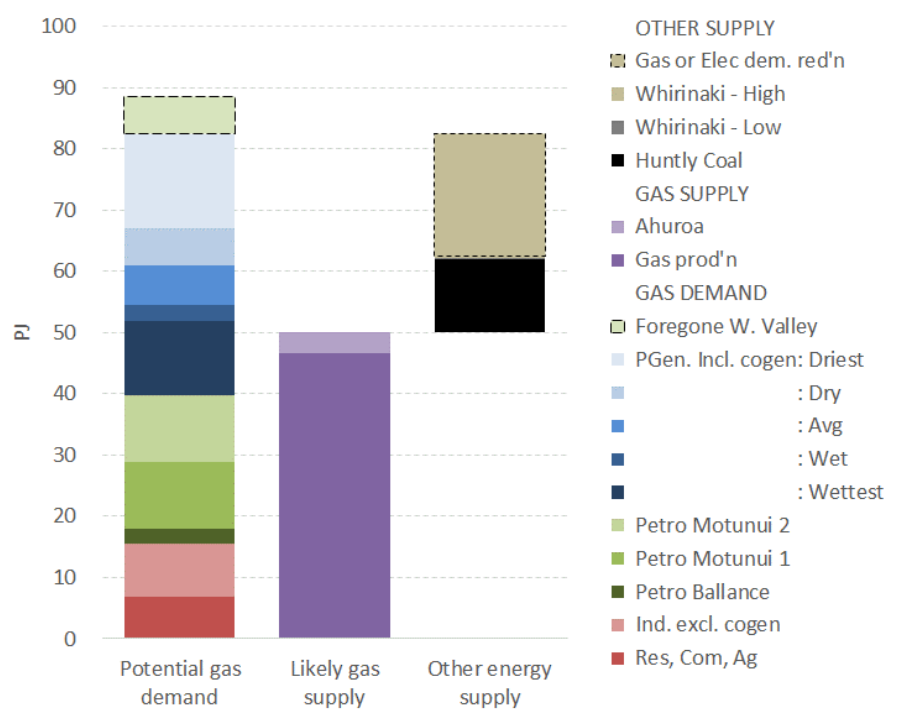
Figure 4 draws the supply and demand estimates together. The first column shows a stack representing the expected demand for gas in winter 2021. The red and green segments are comprised of relatively predictable residential, commercial, industrial, and petrochemicals demand. These can be regarded as firm sources of demand.[20]

The blue segments show potential demand that is increasingly uncertain because it depends on the need to run gas-fired power stations (including cogeneration). The navy segment shows gas demand in a 'wet' scenario (when need for gas is lowest as there is ample hydro generation). The increasingly lighter blue segments correspond to the rising gas demand as hydro conditions become dryer.

The top green segment (with the dotted border) is the amount of gas the Waitara Valley methanol plant would have consumed had it not shut down from February 2021 due to lack of firm gas supply.

The second column shows the expected supply available from producing gas fields and the Ahuroa gas storage facility. As shown, this level of supply is unlikely to meet aggregate demand - even if this winter turns out to be very wet and gas demand for power generation is low. The size of the gap will increase if New Zealand experiences a dry winter.

*Figure 4: Supply-demand balance for Winter 2021*




Gas_S_D_Short_Term_v03.xlsx

While the chart shows a gap between potential gas demand and expected supply, we do not think this will compromise gas supply to mass market users or electricity generators. This is because:

1) a significant amount of fuel for thermal generation can be provided by sources other than gas – principally coal-fired generation in Huntly Rankine units, and (to a much lesser extent) diesel-fired generation at Whirinaki or Huntly unit 6

[20] Firm in the sense that they will take gas if it is available.

2) there is the potential for some 'demand diversion' which could temporarily reduce gas and/or electricity demand and preserve supply for higher-value users. This could entail:

   a) some gas users reducing demand and on-selling some of their entitlement to gas-fired power stations

   b) some electricity consumers reducing demand.

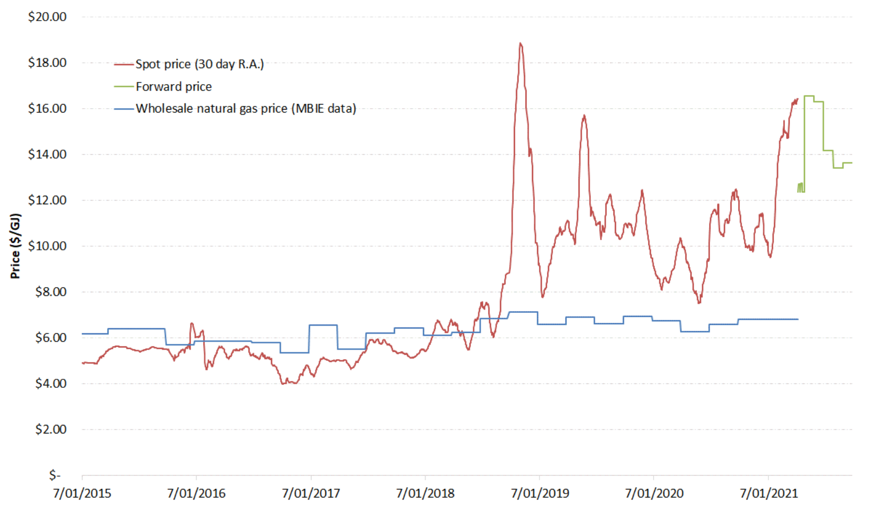
Barring any major plant failure in the gas supply chain, we expect sufficient gas to be available to meet physical demand for residential, commercial and small industrial users. However, the tight supply position is contributing to high prices for gas in the spot market and for shorter term contracts. These high prices will hurt gas users who are not protected by longer term contracts. This issue is particularly relevant for wholesale customers on fixed term contracts which are coming to an end and who face sizeable price increases due to much tighter supply conditions.

Another factor contributing to higher gas spot prices is the recent increase in gas demand for power generation to offset lower hydro generation caused by drought conditions. Tight supply in the electricity market has raised wholesale electricity prices and increased the ability of generators to pay for gas.

The expectation of continuing high gas spot prices for 2021 (especially in winter) is borne out by market data. Figure 5 shows spot gas prices (a 30-point moving average in red) for the period up to 31 March 2021. From that date forward, the chart shows forward prices for gas deliveries later in 2021 (in green).

There has been a clear rise in gas spot prices in the early part of 2021. This coincides with the confirmation that ongoing supply problems are expected at Pohokura for 2021 and continuing dry conditions. The chart also shows that gas prices for short term contracts in winter are also high, reflecting an expectation of rising gas demand with winter.

***Figure 5: Spot and forward gas prices***



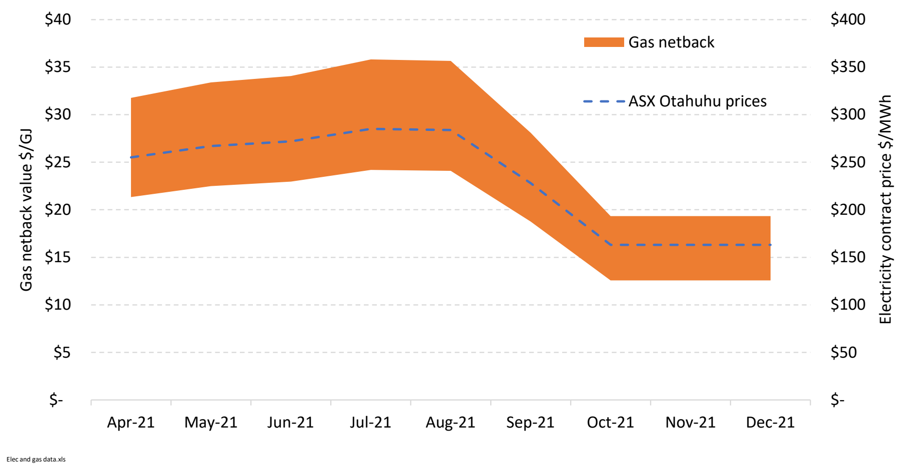

Source: Concept analysis of emsTradepoint data and MBIE data

Having said that, it is important to note that most gas customers do not pay the spot price for gas. Indeed, spot trades traditionally account for less than 5% of total gas sales. Most customers prefer to enter into contracts with a supplier ahead of the gas delivery date and pay the price agreed in the contract. Although contract prices are confidential to the counterparties, the so-called 'wholesale natural gas price' published by MBIE each quarter is a fairly good proxy for the prevailing gas price for large contracts.

As shown in Figure 5, contract prices are much less volatile than spot prices. At times spot prices have been below contract prices such as 2016-2017 when there was ample supply. In the last two years spot prices have been above contract prices reflecting tight supply. Customers (and suppliers) who chose not to contract ahead will be exposed to spot prices, which may turn out to be higher or lower than contract prices. Similarly, gas customers who have contracted for gas can choose to sell some at the spot price if they are able to reduce their usage.

Another indicator which indirectly supports the expectation of continuing high gas prices in the spot market in 2021 is the forward contract price for electricity. As shown in Figure 6, electricity contract prices for winter 2021 are above $250/MWh. After allowing for other operating costs, the implied breakeven fuel price that gas-fired generators could pay for gas is above $20/GJ, depending on conversion efficiency.

***Figure 6: Electricity prices and estimated value of gas for power generation***




Source: Concept analysis of data as at 8 April 2021. Values quoted on a carbon inclusive basis to be comparable to eTp spot prices.

If current market conditions continue, power generators are likely to be able to offer high gas purchase prices to encourage some other gas users to scale back their demand, allowing gas to be diverted to power generation. Historically, very large gas users (especially Methanex) have been among the most important sources of such demand response.

However, even though generators may have an apparent ability to pay a high gas price to encourage gas diversion from other large industrial users, it may not always occur. The reasons include:

- industrial gas users may not be able to alter their gas demand because of the notice periods needed to ramp production up or down
- altering industrial production levels (and gas use) may disrupt product supply chains, cause a loss of contracts, adversely impact on plant life or maintenance costs, or have health and safety implications. This in turn may mean that a turn down needs to meet minimum volume and/or duration requirements to recover the associated costs
- the ability to turn down will be affected by the starting position of a gas user. If it is already running close to its minimum stable demand, it will have little or no ability to turn down further
- industrial users may face different reporting requirements if they are considered to be trading gas, making them reluctant to sell gas unless there is a core operational reason for doing so.

More generally, electricity sector participants will likely also be considering non-gas sector options if conditions remain very dry, such as reducing aluminium production at Tiwai. There is also a possibility that a large inflow event will suddenly change the outlook (though the probability declines as winter approaches as precipitation will fall as snow). All of these factors are examples of 'frictions' which apply to real-world decisions, and which may hinder gas diversion which otherwise appears economic to undertake.

In summary, if it remains dry power generators are likely to continue to bid aggressively for any discretional gas that becomes available. This includes gas that arises from demand diversion by other gas users. While this dynamic helps to keep the lights on, it is painful for wholesale gas customers not covered by existing longer-term contracts. In particular, commercial and industrial customers whose existing term contracts are coming to an end will often face a difficult choice between re-contracting at a much higher price, taking spot exposures or scaling back their operations to reduce gas usage.

## 3.6 Peak daily demand

The preceding analysis focuses on whether sufficient gas will be available to maintain security of supply over the winter *months* if there is high demand for gas-fired generation due to dry conditions.

A distinct but related question is whether security can be maintained on a *day* if there is extremely high gas demand. For example, this could arise due to a combination of extremely cold weather (lifting heating demand for gas) and sustained calm and dry conditions (lifting power demand for gas).

To examine this issue, we compare the peak system-wide daily demand for gas with the combined supply from all gas sources. We start by looking at historical data for 2011 to 2020. We use published data for withdrawals from the national pipeline system to represent demand, noting this may not capture all gas flows (e.g. from Kapuni to the Whareroa cogen plant).

In addition, it is important to note the system peak demand includes the effect of diversity, i.e. users do not all have their peak use on the same day. The estimated supply deliverability is based on the P99 output for each gas source, and the combined total is used to represent potential daily supply. This assumes there is no diversity effect to consider on the supply side of the system.

To estimate the supply position in winter 2021, we start with the estimated peak deliverability from supply sources. For gas fields, we have used the average daily deliverability estimates adopted for the analysis in section 3.3. We consider this to be reasonable given that very tight supply conditions means that fields will run at (or very close) to full output on most days.

For Ahuroa, we assume that deliverability on the peak day will be 65 TJ rather than the average winter level of 30 TJ/day. This is because we expect average withdrawals over winter to be limited by the gas available in storage, whereas peak deliverability will be limited by the physical capacity of the compressors and related plant at Ahuroa.

For demand, we start by identifying the day in 2018-2020 when the combined demand from all gas users except Huntly Rankine units and Methanex reached its peak level. We exclude these two users because as discussed earlier, their demand tends to be more sensitive to gas market conditions than that of other users. Given the tight conditions expected throughout winter 2021, we consider it reasonable to exclude their usage when seeking to estimate the level of peak 'firm demand' in 2021.

The peak day in 2018-2020 was on 16 July 2020. Our peak daily demand estimate for residential, commercial and industrial users (labelled "mass market & industrial" on the chart) is the level of usage observed on that day. The only adjustment made to this figure is to reduce demand at the Marsden Point refinery by 50% as discussed in section 3.4.2.

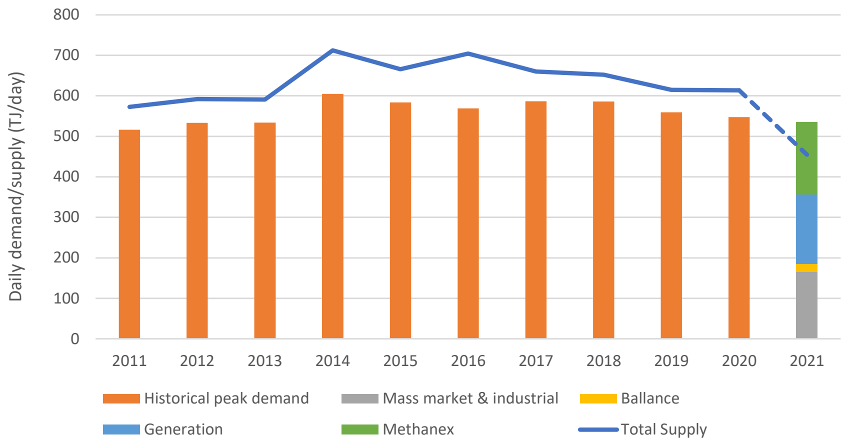
Likewise, we adopt the demand levels observed on 16 July 2020 for Ballance and gas-fired generation as their respective peak daily estimates for 2021. The resulting figure for gas-fired generation is 172 TJ. As a point of comparison, the absolute level of peak demand for gas-fired generation (excluding Huntly Rankine units) in 2018-2020 is 180 TJ which occurred on 31 January 2018. We have not used that figure because we understand coal operation at Huntly may have been restricted at the time, increasing the need for other gas-fired generation. Coal restrictions are not expected to apply in winter 2021, given our understanding that Genesis is likely to be able to import sufficient coal to meet its needs.[21]

In any case, had we adopted the slightly higher figure it would not materially alter the results of the overall analysis. For completeness, we note that the generation estimate assumes that the Huntly Rankine units will be running entirely on coal if they are required. That assumption appears reasonable in light of the announcement by Genesis that it would prepare three Rankine units for potential coal-fired operation for this winter.

The other source of gas demand to consider is methanol production. We have assumed that demand to be 178 TJ/day for the reasons set out in section 3.4.3.

[21] If Genesis did face constraints on its ability to obtain coal supplies, this would increase gas demand (all other factors being equal) and have a material adverse effect on the gas supply/demand outlook for winter 2021.

*Figure 7: Estimated peak daily demand and deliverability*




Source: Concept analysis

The resulting peak demand and deliverability estimates are shown in Figure 7. The analysis indicates there was a positive deliverability margin of around 10-15% in most years between 2011 and 2020.[22] However, there is a marked change in 2021. Indeed, if all gas users operate consistent with the estimates noted above, projected deliverability in winter 2021 would fall short of peak demand by around 80 TJ/day.

As noted earlier, Methanex's gas demand has generally been responsive to short-term emergency gas system conditions in the past. While there is no certainty of such response in winter 2021, if demand response did occur there would be sufficient deliverability to satisfy peak demand for all other gas users while maintaining some gas for Methanex.[23] Having made this observation, flexing gas use would undoubtedly disrupt Methanex's operations and impose costs. For this reason, if such response occurred, we expect that it would be accompanied by very high spot prices for gas.

## 3.7 Current tight supply reflects two unusual factors

We think the tight conditions for this winter reflect two unusual factors:

- Unexpected major problems at New Zealand's largest gas field, Pohokura. Despite efforts to address these issues, the field production capability is expected to be around 50% of its previous levels this winter.[24]
- The pace of new renewable power station development has been slowed by uncertainty over the future of the Tiwai aluminium smelter. Absent this factor, more renewable generation would have been onstream for this winter, lowering the demand for thermal generation.[25]

[22] The headroom was much higher in the 2016, in part due to retirements of thermal power stations.
[23] We note that Methanex is not the only user which tends to respond to system conditions. Some other gas users reduce their demand by deferring usage or switching to alternative fuels at times. However, those effects should already be captured in the peak demand estimates derived from analysis of historical data.

[24] When fully operational, roughly half of Pohokura's gas comes from offshore wells.
[25] This view is borne out by announcements to proceed with new generation developments by Contact and Meridian shortly after the Tiwai smelter indicated it would continue operation until 2024 (or later).

***Figure 8: Supply-demand balance for Winter 2021 plus 'lost' supply***

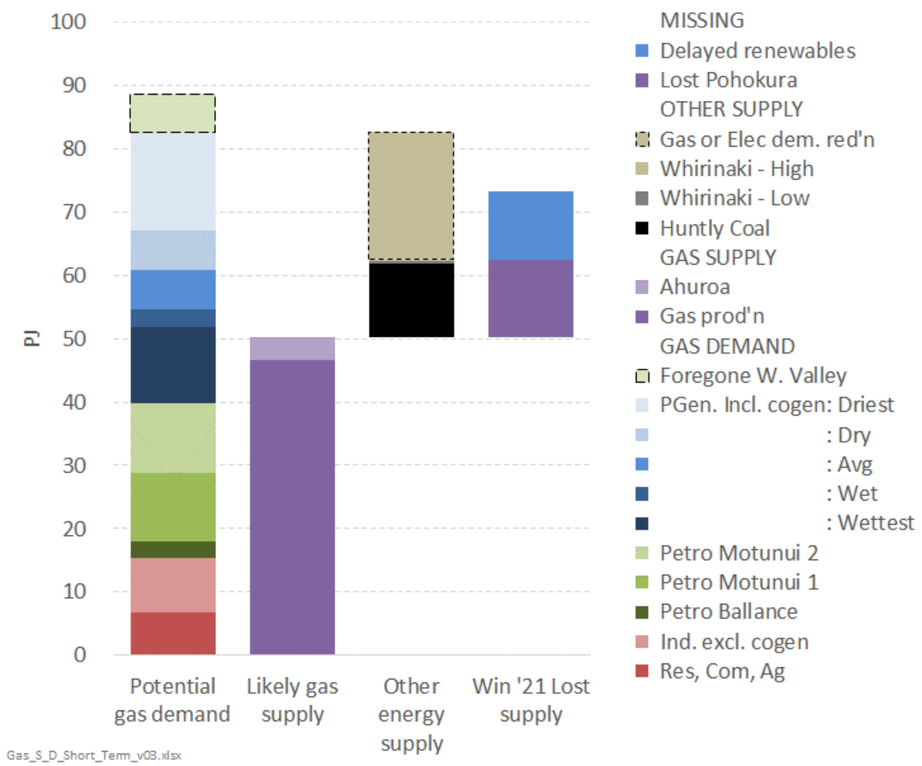



Figure 8 shows the effect of these two factors. The column labelled 'lost supply' shows the estimated impact of the Pohokura supply issues (in purple) and the delays in renewable generation development (in blue).

The combined impact tightens the gas supply demand balance by around 25 PJ in winter. Had these factors not applied, there would have been ample gas supply, including in a dry year.[26]

[26] This is because the sum of the 'missing supply' bars plus the coal bar is sufficient to meet gas demand in even the driest situation. Furthermore, the supply position would likely have been even better than Figure 8 shows as Ahuroa would probably have more gas in storage. If it had been three-quarters full coming into this winter (a more likely 'usual' level) there would be an extra 8.5 PJ gas supply available.

# 4 Outlook for 2022-2035

## 4.1 Summary – outlook for 2022-2035

The tight supply conditions being experienced this year appear likely to continue into 2022. There is a possibility this will be avoided if remedial work at the Pohokura field can be undertaken over the coming summer. However, the timing of this work is uncertain and even if it could be undertaken in the coming summer there is no guarantee it will be successful.

By 2023-2024 there is more confidence that tight conditions will ease. This reflects an expectation that planned work programmes at Kapuni, Kupe, Mangahewa, Maui, and Turangi will have been undertaken by then and will bring more gas to market.[27] In addition, committed new renewable power projects will be on stream, reducing mean gas demand for power generation. Together these factors are projected to lift supply available to other gas users by around 30-45 PJ per year by 2024. If the Tiwai smelter closes at the end of 2024 (the middle case assumption) that will further increase gas available to other users.[28]

Looking out further, there is sufficient gas 'in the ground' to meet mass market, industrial and power generation demand until at least 2035 (and likely significantly beyond). Out to 2027, that production could come largely from existing reserves but beyond then is likely to require development of contingent resources.

Moreover, there is likely to be sufficient headroom in the supply outlook to support operation of 1-2 methanol units on a steady basis until at least 2030, depending on the rate at which other gas demand recedes and how quickly contingent resources are developed. It is also possible that there would be sufficient gas to operate a third unit, albeit on a less certain basis.

Ultimately, the availability of gas for all users depends on producers' willingness to invest more capital in supply-side assets. The investment requirements are potentially very large. Gas Industry Co estimates the industry needs to invest $300-500 million every 3 to 5 years to produce existing reserves and maintain production levels. Some industry experts project even higher annual requirements. For example, Enerlytica recently projected that over $2 billion would be required during the 2020s to maintain current production levels.

The level of investment will be influenced by wholesale customers' willingness to sign multi-year contracts. Looking forward, we expect mass market and industrial gas customers to continue to be attractive to producers as a source of contracts to underpin investment. Similarly, we expect petrochemical producers (especially for methanol production) to remain as a foundation to underpin investment in reliable gas supply.

The demand segment that we think will have the greatest challenge in securing gas is power generation. In particular, power generators may face increasing difficulty in contracting supply for the portion of their demand that is unpredictable because producers will not invest in supply-side assets without relatively firm sale commitments. The question then becomes how power generators obtain their flexible fuel needs during the transition to 100% renewable electricity – a transition that is expected to last for many years. This challenge will become even greater as Genesis reduces coal use at the Huntly power station.

An added challenge in the current environment is that carbon and related policies are yet to be finalised in many areas. Gas sector participants may prefer to delay some decisions until policy is clearer. This could have supply-side implications later in the decade depending on the scale of affected projects and associated lead-times. These points highlight the importance of

[27] This work is reflected in various company statements and/or production forecasts compiled by MBIE and released in mid-2020.

[28] As we discuss later, Meridian Energy is actively pursuing initiatives to stimulate new sources of electricity demand, such as accelerating the uptake of electric boilers for industrial process heat. Growth in demand from other sources may partially offset the effect of a Tiwai smelter closure.

ensuring a smooth transition, but further exploration of these issues is outside the scope of this report.

## 4.2 Projections consider a range of supply and demand scenarios

In this chapter we look further ahead to the period from 2022 to 2035. Gas demand and supply in these years will be strongly influenced by decisions that have yet to be made. On the supply side, producers will be making decisions about whether to commit capital to produce from existing reserves and to convert undeveloped (but identified) gas resources into reserves.

Similarly, major gas users will be making decisions on whether to commit capital expenditure to allow future use of gas in their facilities. The investment requirements are potentially very large. Gas Industry Co has estimated that the industry needs to invest $300-500 million every 3 to 5 years to produce existing reserves and maintain production levels.[29] Some industry experts project even higher annual requirements. For example, Enerlytica recently projected that over $2 billion would be required during the 2020s to maintain current production levels.[30]

Given the uncertainties applying during this period, we have used scenario-based approaches to examine possible outcomes. These scenarios are necessarily broad brush in nature, and should be interpreted as representing different possible future states for the gas sector. It is important to emphasise that the scenarios are not based on detailed bottom-up forecasts – especially on the supply-side of the industry.

The scenarios focus on *annual* demand and supply, rather than winter or peak daily measures. This is because there is too much uncertainty to make robust projections of winter or peak demand. The only exception is winter 2022. This period is little more than a year away allowing us to make reasonable estimates of the winter supply margin.

[29] Gas Industry Co, Briefing to Incoming Minister, October 2020, page 4.
[30] Enerlytica, NZ Gas presentation to NZ Downstream 2021 Conference, March 2021.

## 4.3 Gas supply scenarios for 2022-2035

We have developed a range of scenarios for gas supply capability[31] in the 2022-2035 period. These scenarios are intended to span the plausible range of supply from domestic sources.

We have given separate consideration to gas supply from reserves and contingent resources. Reserves have a higher level of certainty because they are identified accumulations that have already been assessed as commercially justified for production. Having said that, there is still uncertainty about the volume of gas which may be recovered. In addition, market conditions can change in the future which can alter the commercial status of a project to produce gas.

Contingent resources are also known accumulations of gas, but these are not currently assessed as commercially justified for production. This means there is more uncertainty about their future contribution to supply.

In principle, gas may also be supplied from sources that are yet to be identified – such as new onshore fields or as-yet unidentified accumulations in existing fields. We have not made any assumptions about future supply from these sources, although the pattern of updates from past disclosures of reserves and resources would suggest that there is likely to be material additional potential gas from both these sources.

Finally, gas could be imported if required. The latter source is not limited by supply-side factors, but rather viability depends on commercial factors.

In the next sections we describe how the estimates of supply capability from existing reserves and resources have been compiled.

### 4.3.1 Base case - gas supply from existing 2P reserves

The gas production profiles released by MBIE in July 2020 are the foundation for developing the scenarios. The profiles published by MBIE show field

[31] The charts that follow show scenarios of gas supply capability. The volume of gas which is produced in a given year could be lower than the supply capability.

operators' estimates of how 2P reserves will be produced over time. The estimates were compiled in early 2020 and reflect their forecasts at the time.

In our middle case we assume annual production capability at Pohokura will be the same in 2022 as 2021, and thereafter it will be 25% lower than the estimates released by MBIE in 2020.[32] This derating is not based on any specific information provided by the field operator. Instead, it reflects the recent and ongoing issues experienced at Pohokura and an assumption that production from offshore wells will recover after 2022 but only to around 50% of former levels.

We have also slightly altered the profile for Kapuni production to reflect an expected one-year delay in the planned drilling programme. Finally, production profiles for all fields were reduced by 0.4% so that the sum of production equates to the total reported figure for 2P remaining gas reserves. We assume the 0.4% difference reflected the average amount of gas that would have been consumed in operations (i.e. the figures have been adjusted into net production terms). However, this change has little effect on the results.

We recognise that Pohokura and Kapuni are not the only fields whose production profile may change relative to the forecasts in 2020. For example, we understand some drilling campaigns were disrupted in 2020 by the Covid-19 related lockdowns. On the other hand, we understand development activities at some fields were accelerated once problems at Pohokura became evident. Overall, we have insufficient information to know whether the net impact of these other factors is positive or negative. For the middle case we therefore assume supply capability for other fields follows the production profiles disclosed in mid-2020.

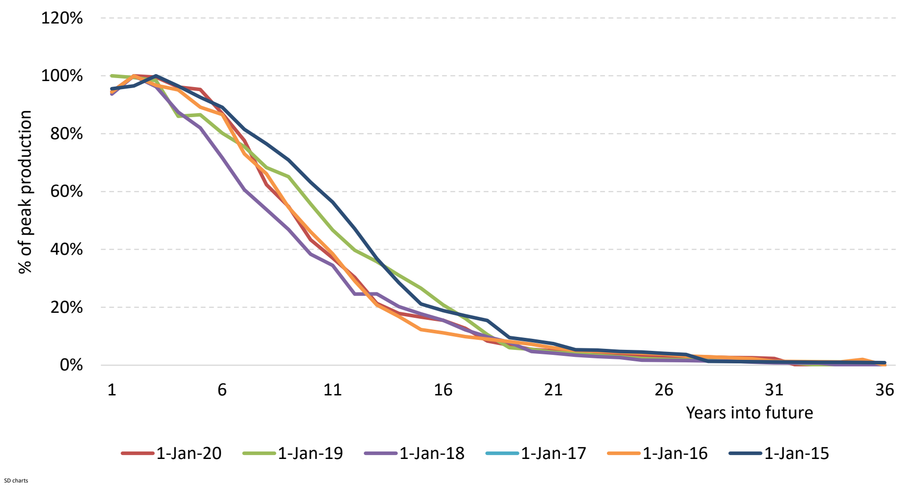
### 4.3.2 Higher case - gas supply from existing 2P reserves

In our higher case, we assume work at Pohokura this summer results in a complete restoration of supply capability and the production profile forecast in early 2020 can be achieved. We have not made any adjustments to middle case assumptions for production from other fields.

### 4.3.3 Lower case - gas supply from existing 2P reserves

In the lower case we assume production from Pohokura's offshore wells does not recover to former levels. This is assumed to cut Pohokura production by around 50% compared to the projections released in 2020. For other fields we have not adopted bespoke assumptions. Instead, we have assumed that all fields decline from their peak production level after 2022. Although this is clearly a stylised assumption, we think it is not unreasonable as a sensitivity case in light of past experience.

***Figure 9: Previous forecasts of gas production from existing fields***




Source: Concept analysis of MBIE data

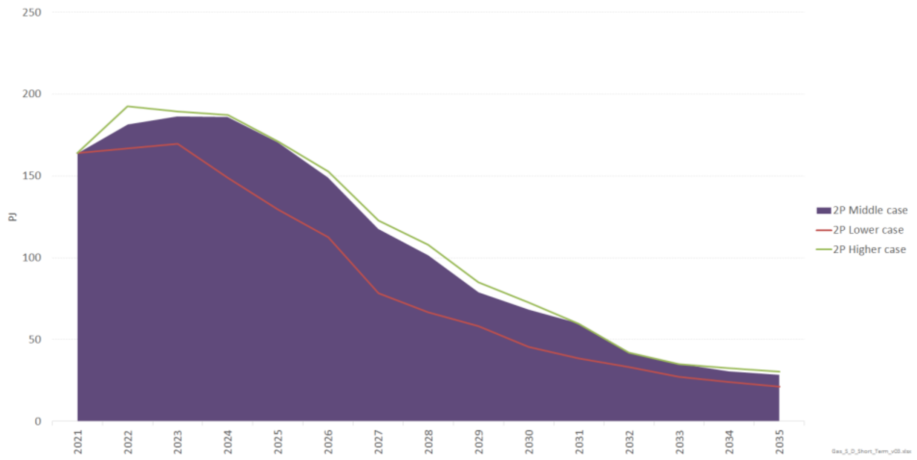
Figure 9 shows gas production forecasts from then existing fields issued between 2015 and 2020. They are expressed as percentages of peak forecast production for each year into the future to facilitate comparisons.

[32] As a result, there is still an increase in production from 2021 levels.

The different forecasts had projected plateau periods of varying durations (from 1-5 years), but then had a similar shape once the decline phase was established. In essence, our sensitivity case foreshortens the plateau periods that were contained in the 2020 MBIE projections and assumes a decline from 2022.

The combined effect of the assumptions for the various cases is shown in Figure 10.

***Figure 10: Projected gas production from 2P reserves***



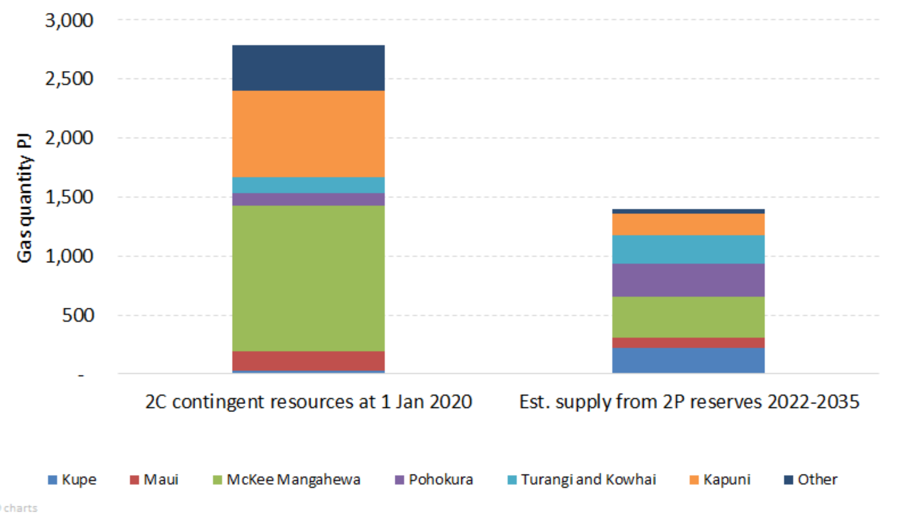

Source: Concept analysis of MBIE data

### 4.3.4 Gas supply from existing contingent resources

Existing *gas reserves* are not the only source of possible supply. In addition, gas may be supplied from *contingent resources*. These are quantities of gas estimated to be potentially recoverable from known accumulations, but which are not considered to be commercially recoverable at the date of the estimate owing to one or more contingencies.

As shown in Figure 11, the estimated quantity of contingent resource gas associated with currently producing fields is substantial. Indeed, it significantly exceeds the volume of gas supply we expect to be available from 2P reserves in 2022-2035.

***Figure 11: Gas reserves and contingent resources***




Source: Supply from 2P reserves is estimated from analysis noted above. Contingent resource estimates are as reported by MBIE but excluding estimates for Karewa and Moturoa fields as neither were in production in 2021.

Having said that, there is significant uncertainty about what proportion of this contingent resource will ultimately be economic to produce, and hence converted into reserves. To reflect this uncertainty, we have developed three scenarios:

- In the higher case, we assume 75% of currently reported contingent resources is available to convert into reserves and support gas production
- In the middle case we assume a 50% conversion rate
- In the lower case we assume a 25% conversion rate.

While these scenarios are 'broad brush', we think they reflect a range of plausible future supply-side outcomes because:

- Over the last decade there has been a relatively steady rate of reserves replacement (around 200 PJ per year on average). In part this has been driven by reserves being 'used up', tightening the margin between remaining reserves and expected future demand and thereby making it economic to bring forward the development of contingent resources which previously were uneconomic to develop. If this rate of replacement were to be maintained for another decade from the existing estimate of 2C contingent resources, that would imply a conversion rate of around 75%.

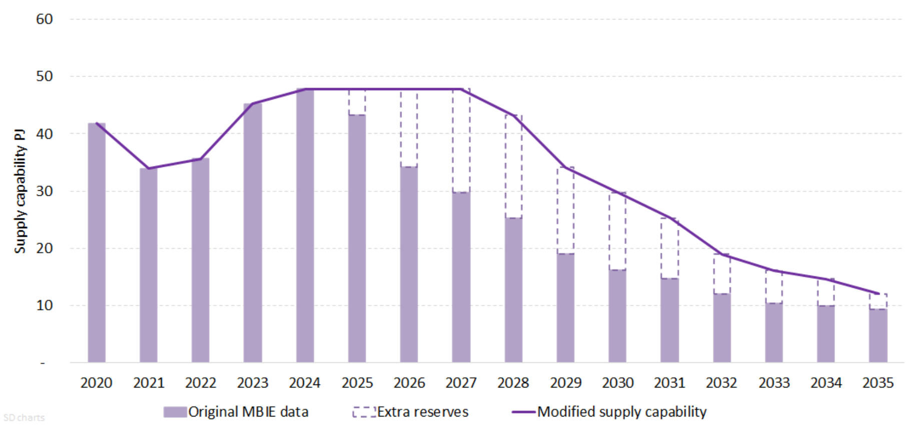
- Gas demand in the coming decade is likely to be lower than in the 2010s, in particular due to the effect of rising carbon charges. All other things being equal, this would be expected to reduce the commercial attractiveness of some projects. The middle and lower case scenarios reflect this general expectation.

We note these assumptions refer to the proportion of existing 2C contingent reserves[33] which will be converted into reserves and available for production in 2022-2035. It is possible that further hydrocarbon accumulations, including those associated with existing fields, will be identified before 2035 and may be added to the estimate of 2C contingent resources. This would increase the pool of contingent resources available to provide supply. On the other hand, some of the already identified contingent resource may not be available for production until after 2035 due to physical or commercial constraints. In effect, the scenarios treat these factors as offsetting each other.

Finally, the above scenarios alter the total stock of gas assumed to be available for production in 2022-2035. There is also the question of how much of the available stock could be produced each year. This is also uncertain and will depend upon factors such as well deliverability rates and processing capacity at various plants. In the absence of more specific information, we have assumed that converting resources into reserves has the effect of extending the pre-existing peak level of production capability for each field. It does not otherwise alter the 'shape' of the production profile.

[33] Estimated to exist as at 1 January 2020, and from currently producing fields.

*Figure 12: Illustrative effect of reserves addition on supply capability*



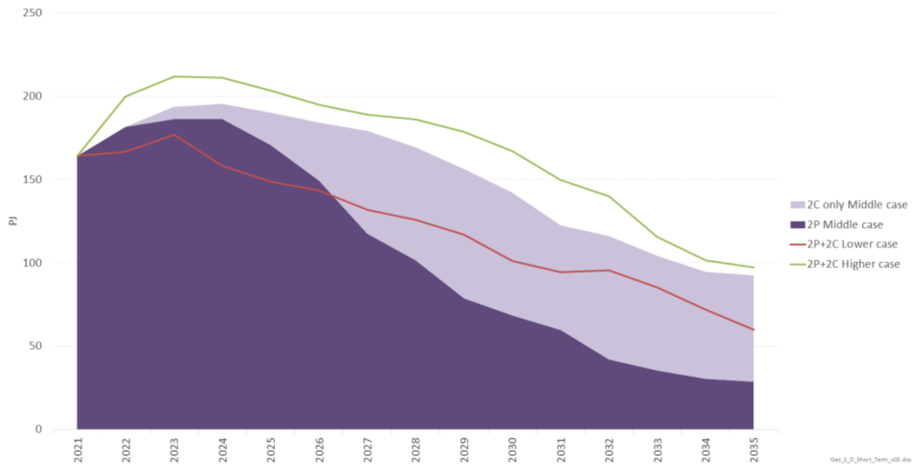

Source: Illustrative projections

This approach is illustrated in Figure 12 using data for McKee Mangahewa as an example. The solid bars show the forecast 2P production profile reported by MBIE in mid-2020. The peak level of gas production was projected to be 48 PJ in 2024 followed by a progressive decline. Our approach preserves the peak production level of 48 PJ as the upper limit on supply capability, but additional reserves are assumed to allow peak production to be maintained for more years. Thus, in a scenario where reserves for the McKee Mangahewa fields are increased by (say) 80 PJ as shown in the dotted bars, this has the effect of extending the period of peak supply capability by three years. Thereafter, the fields are assumed to decline at rates that match the shape of the previously reported profile. The combined new profile is indicated by the solid line.

### 4.3.5 Gas supply scenarios

Figure 10 above shows how gas supply from existing 2P reserves is assumed to vary under the different cases. As discussed earlier, all of the assumed variation between the middle and higher cases stems from the Pohokura field, over which there is significant uncertainty in the next few years. Looking further out, all of the cases assume a significant drop in supply capability from existing 2P reserves, with total supply dropping by around 75% by 2035. The fall-off in supply from reserves means that development of contingent resources would become progressively more important.

***Figure 13: Gas supply capability from 2P reserves & 2C resources***




Source: Concept projections

Figure 13 shows the assumed total level of supply available from *2P reserves and 2C resources* in the middle case (indicated by shaded areas). The variation in total supply under lower and higher cases is shown by the lines.

## 4.4 Gas demand 2022-2035

The approach adopted to compile demand projections for each segment is described below.

### 4.4.1 Gas demand for residential/commercial/agriculture

Gas demand for residential, commercial and agricultural users (also called the 'mass market') reflects the outcome of decisions by many thousands of consumers. Because decisions to switch energy source (to or away from gas) typically involve capital expenditure for appliances and modifications to premises, there are unlikely to be sudden shifts in the level of annual gas demand for these users.

Having said that, demand will be affected by factors such as population growth, levels of economic activity and by government policy (especially carbon-related policies).

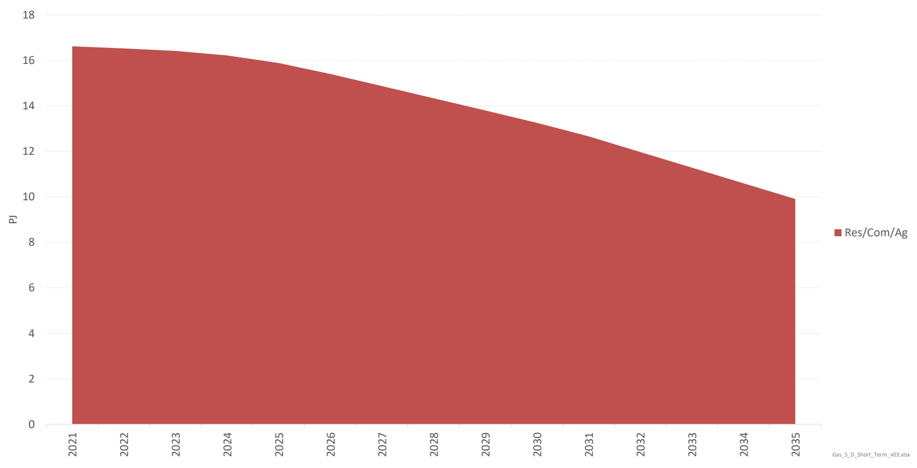
In light of these factors, our middle case aligns with the gas demand forecast prepared by the Climate Change Commission in its draft carbon budget report issued in January 2021.[34] We understand this forecast takes account of economic factors such as population growth, but also incorporates the expected effect of carbon-reduction measures being proposed by the Commission.

We note a similar carbon reduction outcome could occur if the required emissions reductions from the gas sector to get to net-zero emissions by 2050 were not achieved via such a mass switching from gas to electric, but instead achieved via reticulated gas pipelines having an increasing proportion of 'green gas' (hydrogen or bio-methane), moving to 100% green gas by 2050.

The resulting middle case projection has relatively flat demand until 2025, followed by a decline from that year as shown in Figure 14. By 2035 gas demand is projected to have fallen by approximately 40%. Although other scenarios are plausible for this segment of demand, it is fairly small in volume terms relative to total gas demand. For this reason we have not included any higher or lower cases for mass market demand.

[34] See www.climatecommission.govt.nz/get-involved/our-advice-and-evidence/

*Figure 14: Mass market gas demand projections to 2035*




Source: Concept projections

### 4.4.2 Gas demand for larger industrial users (except petrochem)

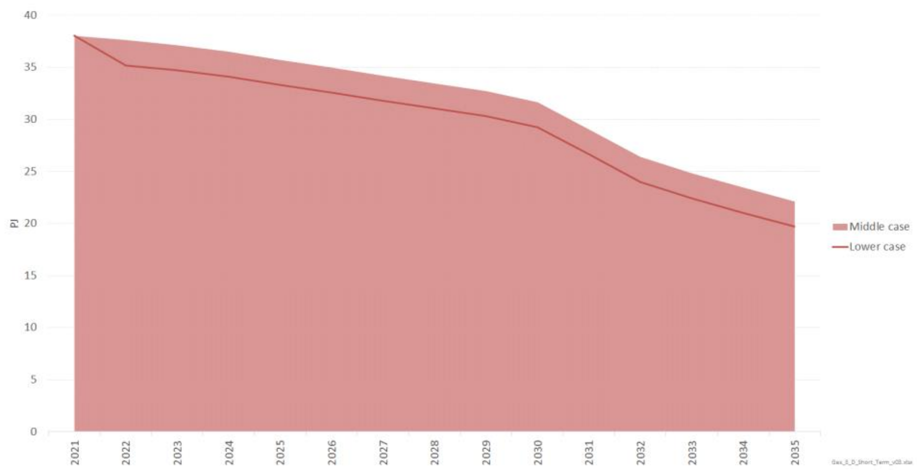
For our middle case projection of large industrial user demand (ex. petrochem), we have adopted the forecast in the Climate Change Commission's draft report.[35] This is shown in Figure 15.

That forecast has gas demand which declines fairly slowly over the 2022-2035 period. We understand this reflects a combination of rising economic activity, offset by higher energy efficiency and a trend toward lower emission fuel sources, such as bio-fuels. Having said that, the decline is initially fairly gradual, in part because of the lead time required to make significant changes to industrial boilers and other equipment at existing industrial facilities.

For our lower case, we assume the Marsden Point refinery becomes a fuel import terminal and ceases to use gas from 2022. We do not include a higher case as we are not aware of any factors that would materially lift demand for this segment.

[35] We note the Commission includes cogen demand as part of industrial gas use. As discussed elsewhere, we classify cogen as part of power station demand for gas in this report.

*Figure 15: Industrial demand projections to 2035*




Source: Concept projections

### 4.4.3 Gas demand for power generation

As discussed in section 3.4.4, gas demand for power generation has two main components – cogeneration and the remaining demand which is the difference between total electricity demand and supply from all other forms of generation.[36] Two key factors are expected to materially affect gas demand for this remaining generation over the period to 2035:

- Electricity demand growth is expected to accelerate as an increasing proportion of New Zealand's total energy needs is met from electricity. For example, electric vehicles are expected to substitute for petrol and diesel-powered vehicles.
- An increasing share of generation is expected to come from renewable sources. In part this reflects a catch-up from previously delayed investments. However, renewables are also likely to be increasingly competitive with existing thermal stations – particularly for higher capacity-factor duties – as the cost of wind and solar generation continues to fall and carbon charges increase.

[36] And adjusted into gas equivalents based on conversion efficiency of the relevant stations.

While there is uncertainty over the balance of the two factors noted above, we concur with the view of most forecasters that the latter will predominant – and that the share of generation from gas-fired plant will decline over time.

In our middle case, we have broadly adopted the estimates in the Climate Change Commission's draft report.[37] By way of summary, these assume the Tiwai smelter closes at the end of 2024, that other demand sources such as electric vehicles increase, and that by 2035 renewables account for approximately 96% of electricity generation in an 'average' hydrology year – i.e. at the P50 hydro inflow level.

We are aware that Meridian is seeking to stimulate alternative new sources of electricity demand to offset the effect of a Tiwai smelter closure. We think such demand growth to the extent it emerges will not materially alter the demand for gas-fired generation. This is because growth in electricity demand will likely encourage further investment in renewable generation, leaving demand for gas-fired generation largely unchanged, all other things being equal.[38]

These estimates also incorporate relatively stable gas demand for cogeneration. In an average hydro year, just over half the 4% from non-renewable generation plant is from fossil-fuelled cogeneration, with the remainder coming from gas-fired peaking plant performing dry-year and other renewable balancing duties.

From an emissions perspective, in the Climate Change Commission's draft report, by 2035 45% of electricity sector emissions come from geothermal power stations, with the remaining 55% split roughly half between cogeneration and gas-fired peaking plants.

[37] As we discuss later, these estimates are for mean gas demand across a range of hydrology sequences.

[38] As we discuss below in the higher gas demand case, we think that if smelter operation were to unexpectedly continue beyond 2024, that would lead to higher gas-fired generation until renewable generation catches up with power demand. We think the smelter is different to other electricity demand sources because of its very large size and the binary nature of whether it continues in operation.

For our lower gas demand case, we assume that by 2030 renewables account for 100% of electricity generation in an average hydrology year (but with some peaking generation used in a dry year) and that this balance of renewable and thermal generation is maintained out to 2035. We have included this scenario to reflect the target announced by the Government of reaching 100% renewable electricity by 2030.[39] The target has not specified whether cogeneration would be classified as gas-fired generation or not.

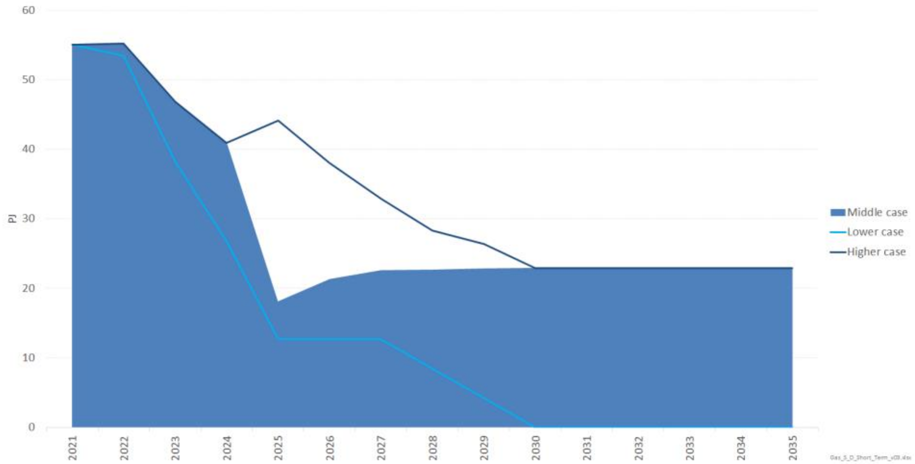
Given that the lower case is intended to reflect a downside scenario for gas demand, we have assumed that cogeneration would be treated as gas-fired generation and thus phased out by 2030. However, as shown in Figure 15, other industrial gas-fired boilers for process heat without cogeneration would continue to operate. Overall, this scenario results in almost 99% renewable generation across the average of all hydrology states (i.e. 'wettest' to 'driest')

For our higher case, we adopt the same assumptions as the middle case except we assume the Tiwai aluminium smelter continues to operate from 2025 onwards. This scenario assumes the continued Tiwai smelter operation is not known until 2024. Accordingly, this additional demand is 'unexpected' and therefore met initially by higher gas-fired generation. However, we assume new renewable sources are progressively developed to offset this demand and by 2030 gas-fired generation returns to the same level as the middle case.

Figure 16 shows the gas demand trajectories under the three cases. All show a significant drop in projected gas use for generation over the next few years. This reflects the growing share of power demand from new renewable projects, reducing the need for thermal generation. Indeed, the middle case only includes projects which have been committed for development, such as the Turitea and Harapaki wind farms and the Tauhara geothermal station. These projects can be treated as certain given that they have been committed.

[39] The Government has previously had a target of reaching 100% renewable by 2035 and brought this forward to 2030. It is currently exploring options to achieve this target. See www.beehive.govt.nz/speech/speech-throne-3

*Figure 16: Potential gas demand for power generation*




Source: Concept projections

In addition, there is a further substantial projected drop in gas-fired generation after 2024. This drop is not certain, as it reflects the assumed closure of the Tiwai smelter from 2024. As noted earlier, if the smelter remained in operation this would likely lift demand for gas-fired generation (shown in the higher case) until further new renewables were developed. The lower case shows the projected trajectory if gas-fired generation is phased out by 2030.

As discussed in section 3.4.4, the requirement for gas-fired generation is expected to vary with hydrology. The cases shown in Figure 16 are all based on mean hydro generation. Annual hydro generation can vary by +/- 3,000 GWh. If this variation were to be met entirely by thermal fired generation that would imply an annual fuel swing requirement of up to +/- 30 PJ. Some of this can currently be met by coal-fired generation (if the Rankine units are able to operate on coal) but not all of the requirement. Similarly, demand reduction may be appropriate for meeting some of the swing requirement for the very driest of hydrology sequences, but to a fairly limited extent.

#### 4.4.4 Petrochemical manufacturing

Our middle case assumes that gas demand for ammonia urea manufacturing remains at current levels for the forecast period. This is consistent with the projections in the draft report from the Climate Change Commission.

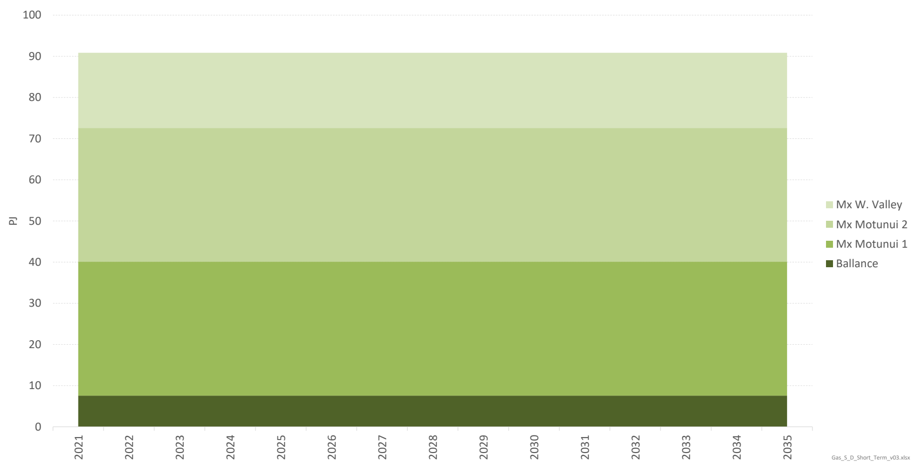
For methanol production, we do *not* make any assumptions about the level of gas demand. Rather, we treat gas demand as an *outcome* of the analysis, by considering how much gas is available for methanol production after satisfying other sources of gas demand.

We note that the level of gas demand would depend on which (if any) of the three plants are operable. The potential demand is 18 PJ for the Waitara Valley plant and around 33 PJ for each of the two Motunui trains (i.e. up to 84 PJ in total).

Whether a plant is capable of operation will depend on whether it has been through a 'turnaround' process. In essence, this involves a major overhaul of the methanol production train, replacement of catalysts and recertification of pressure vessels. Plant turnarounds cost tens of millions of dollars to undertake.

Each train can operate for around five years between turnarounds. Once a train has been through a turnaround, Methanex is likely to seek to run it at or close to full output (subject to gas availability), to spread the fixed cost. On the other hand, if there is insufficient gas available to justify expenditure on a turnaround, a train will be mothballed. Overall, the above means that a decision to turnaround a train means there is gas demand from that train for roughly five years.

*Figure 17: Potential gas demand for petrochemical production*




Source: Concept projections

In light of the above factors, we simply show the *potential* annual gas demand for differing numbers of operating methanol production trains, plus demand from Ballance's ammonia urea plant at Kapuni (shown as "Ballance" in the chart). These differing *potential* demands are shown in annual terms in Figure 17, assuming each unit operates at or close to full output.[40]

Gas demand for ammonia urea production is likely to be the most resilient category within the petrochemical segment. We therefore place it at the base of the stack of potential petrochemical demand. By contrast, we expect gas demand for methanol production to be quite sensitive to medium term gas supply conditions. This is because expenditure on train turnarounds will only occur if there is sufficient headroom in the supply outlook after meeting other demand to also fill that train. This means that gas for methanol production has tended to act as a broad system 'balancer', and we expect that role to continue in the projection period.

Within the methanol production portfolio, we expect the two Motunui trains to generally run ahead of the Waitara Valley train because of their higher conversion efficiency. Our demand stack in Figure 17 reflects these factors.

Having said that, it is possible that the (smaller) Waitara Valley train would be run instead of a Motunui unit if there was insufficient gas to justify operation of the larger unit. This could occur as a combination of the Waitara Valley unit with one Motunui unit, or the Waitara Valley unit might be the only one in operation (as occurred in the mid-2000s). We have not shown the possibility of the Waitara Valley plant moving ahead of a Motunui unit in the chart, but readers should bear this possibility in mind.

## 4.5 Outlook for 2022-2035 – composite scenarios

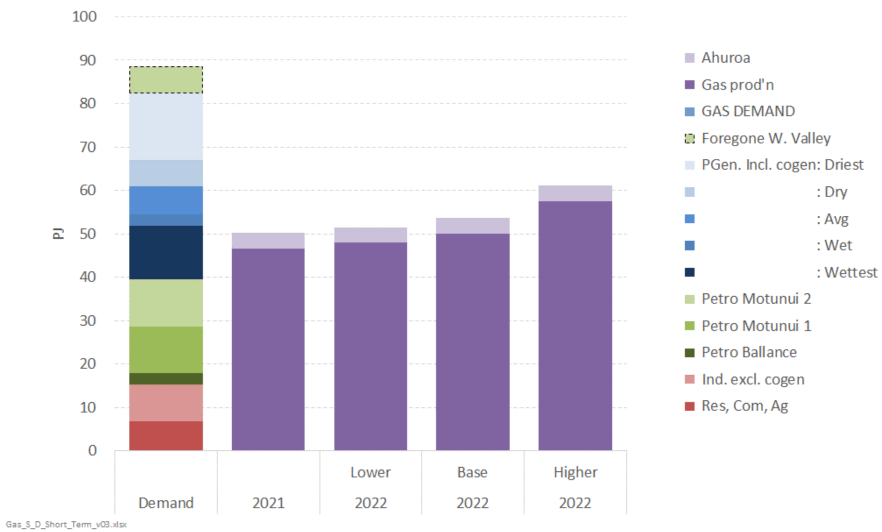
This section brings together the various demand and supply cases into composite scenarios. We focus first on the outlook for winter 2022. We then turn to consider the outlook for annual supply and demand until 2035.

### 4.5.1 Outlook for winter 2022

Figure 18 shows projected gas demand and supply for winter 2022 using the same 'stack' format as Chapter 3.

[40]As noted in section 3.5, on a given day the plants may operate below full output to reflect prevailing system conditions.

*Figure 18: Winter 2022 – projected gas demand and supply*




Source: Concept analysis

Gas demand for 2022 is projected to be almost the same as for 2021 (on a mean hydrology basis). The only notable change is that the Marsden Point refinery may switch to an import terminal, which would reduce winter gas demand by 0.8 PJ. There is a slight reduction (0.5 PJ) in electricity generation requirements due to some new renewables being commissioned in time for next winter and some reduction in refinery electricity demand, the combined effect of which more than offsets the underlying growth in electricity demand.

On the supply side, bigger changes are possible. In the middle case, we are projecting some recovery in gas production at Pohokura.[41] If that occurs, the winter supply/demand balance would improve relative to 2021. However, the change is fairly modest and there would still be insufficient gas supply to meet the full potential demand in a dry year. That in turn means winter electricity supply in 2022 would remain dependent on some combination of coal operation at Huntly, Methanex demand reduction, or electricity demand savings in the event of sustained dry conditions.

There is a possibility that supply capability will improve to a level reflected in the higher case (a restoration at Pohokura to the production profile forecast in early 2020). However, even in that scenario, winter supply in a dry year will still be relatively tight.

Furthermore, there is no certainty that the work to address issues at Pohokura will be successful (or even completed) before winter 2022. This is reflected in our lower supply case. In that event, winter supply for 2022 is expected to be essentially unchanged from 2021.

In short, the supply-demand balance for winter 2022 may improve relative to 2021, but the likelihood and scale of any improvement is highly dependent on the successful completion of planned work at Pohokura over the coming summer. Absent any improvement, winter supply in 2022 looks very similar to that for 2021.

### 4.5.2 Annual supply and demand measures for 2022-2035

We now turn to consider the annual supply and demand outlook from 2022 to 2035. As noted earlier, this is based on a range of demand and supply cases to reflect the wider uncertainty as we look further into the future.

As shown in Table 1 there are nine possible combinations of demand and supply cases. Rather than examine every possible combination, we have focussed on the following:

- Central scenario – this reflects the middle case projections for both gas demand and supply.
- Demand sensitivities – this examines the sensitivity of overall results to variations in demand assumptions (with assumptions for gas supply held constant at middle case settings).

[41] Changes are also expected at other gas fields but these are small relative to Pohokura. See section 4.3.1.

- Supply sensitivities – this examines the sensitivity of overall results to variations in supply assumptions (with assumptions for demand held constant at middle case settings).
- Stress scenario – this is the most pessimistic combination from the perspective of supply reliability because it combines higher demand and lower supply.

***Table 1: Composite scenarios for 2020-2035***

| | **Lower supply**<br>*Pohokura @ 50%**<br>*25% of contingent resource converted to reserves* | **Middle supply**<br>*Pohokura at 75%**<br>*50% of contingent resource converted to reserves* | **Higher supply**<br>*Pohokura at 100%**<br>*75% of contingent resource converted to reserves* |
|---|---|---|---|
| **Lower demand**<br>*Middle case except:*<br>• *100% renewable electricity by 2030*<br>• *Marsden Refinery ceases gas use* | | Lower demand/ middle supply | |
| **Middle demand**<br>*Based on Climate Change Commission projections* | Lower supply/ middle demand | **Central scenario** | Higher supply/ middle demand |
| **Higher demand**<br>*Middle case except:*<br>• *Tiwai smelter continues after 2024* | **Stress scenario** | Higher demand/ middle supply | |

Variation in supply cases (with middle demand)

Variation in demand cases (with middle supply)

### 4.5.3 Outlook for 2022-2035 – central scenario

Figure 19 shows the results of combining the middle case assumptions for both gas supply and gas demand. The demand segments are shown as bands, stacked in broad order of expected sensitivity to system conditions. Thus, mass market demand is placed at the bottom of the stack indicating that it is likely to be the most resilient to system conditions.

The blue band shows gas demand for power generation for mean hydro conditions. The blue dotted lines indicate the expected range around the mean level of gas demand for power generation due to hydrology variation.

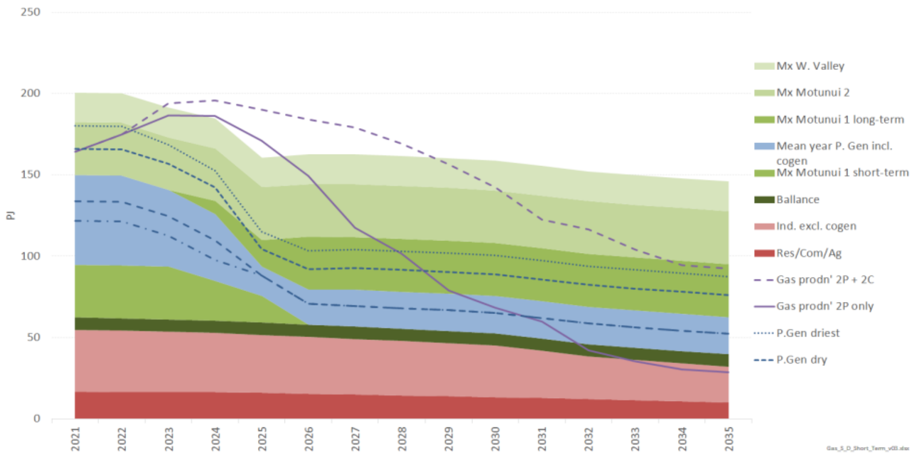
At the other end of the spectrum is demand for petrochemical manufacturing – particularly methanol production. As discussed in section 4.4.4, this source of demand can act as a broad system balancer, scaling up if sufficient gas is available to justify investment in plant turnarounds and scaling down when conditions are tighter.

Having said that, the chart places Ballance's gas demand for fertiliser production ahead of power generation (i.e. lower in the stack). This reflects the apparent resilience of Ballance's gas demand and its lack of history (to our knowledge) in actively reselling contracted gas as a source of demand response.[42]

The chart also shows gas demand for one Motunui unit as being ahead of power generation in the merit-order stack until 2025 and then behind power generation for later years. This ordering reflects a judgment that having recently incurred significant expenditure on a Motunui turnaround, Methanex is strongly motivated to use the unit. Furthermore, past experience suggests that moving from three-unit to no-unit operation within five years is very unlikely. This may reflect the higher disruption costs which would be incurred if rapid and large changes were to occur to global methanol supply chains (noting the New Zealand plants are significant in terms of traded methanol).

[42] Ballance has sold gas that becomes available from maintenance shutdowns, but has not to our knowledge reduced local production and switched to imports in order to free up gas for on-sale.

*Figure 19: Middle case demand and middle case supply*




Source: Concept projections

We should emphasise that the resulting merit order of gas demand reflects our judgement about the average *willingness to pay* for gas of different users. At times, the merit order will change, such as when conditions are dry and power generators have a higher willingness to pay. We also think there is a separate question about *willingness to contract* – which we discuss further in section in 4.6.

The solid purple line shows the projected supply capability from 2P reserves. The dotted purple line shows the supply capability from reserves and contingent resources. (see section 4.3 for more detail). While these should provide a reasonable guide to supply capability in the earlier years, there is more uncertainty further out.

In particular, if supply capability from 2P reserves is not fully utilised in the earlier years, it would typically leave a higher level of remaining 2P reserves[43] available for production at a later date. However, the effect of such deferral on future supply capability would depend upon factors such as deliverability constraints and whether project economics are affected. We are unable to analyse such factors with the information available to us. Instead, we consider these issues in a broad-brush manner via scenario analysis (see the later sections.)

Key observations in the middle case demand and supply scenario are:

- In the early part of the period (2022 and 2023) there is some easing relative to the very tight market conditions in 2021. This is driven by a projected modest increase in gas supply capability compared to 2021. However, the system would still be tight, especially in a dry year.
- Looking further out, gas supply capability from 2P reserves would be sufficient to fully satisfy demand for mass market, industrial (excluding petrochem) and average power generation use out to around 2029. However, this advances to around 2028 if higher gas demand in a dry year is accounted for. In addition, it is important to emphasise that these dates assume a 'just in time' approach to balancing supply and demand. In reality, a supply buffer is likely to be needed as discussed in section 3.6 to reliably cover peak deliverability requirements. These factors would be expected to bring forward the time when new sources of supply are needed to around 2027.
- From 2022 to 2025, gas supply capability from 2P reserves has significant headroom to support gas use for petrochemical manufacturing at Motunui (and possibly Waitara Valley in the later years). The improving headroom reflects the combined effect of a projected modest supply recovery and falling gas demand for power generation. However, beyond around 2025, petrochemical demand would need to progressively scale back unless new supply is developed from contingent resources.
- If 2C contingent resources can be commercially developed as assumed in the middle case, there would be sufficient gas to supply significant levels of petrochemical gas demand as well as all other gas use. In this context, it is also relevant that term contract commitments from

[43] Relative to the level assumed by field operators when they submitted their forecast production profiles to MBIE in 2020, and assuming deferral does not lead to reserves being reclassified.

petrochemical producers have generally been needed to underpin larger new supply sources, especially for offshore sources given their investment scale and timeframes.

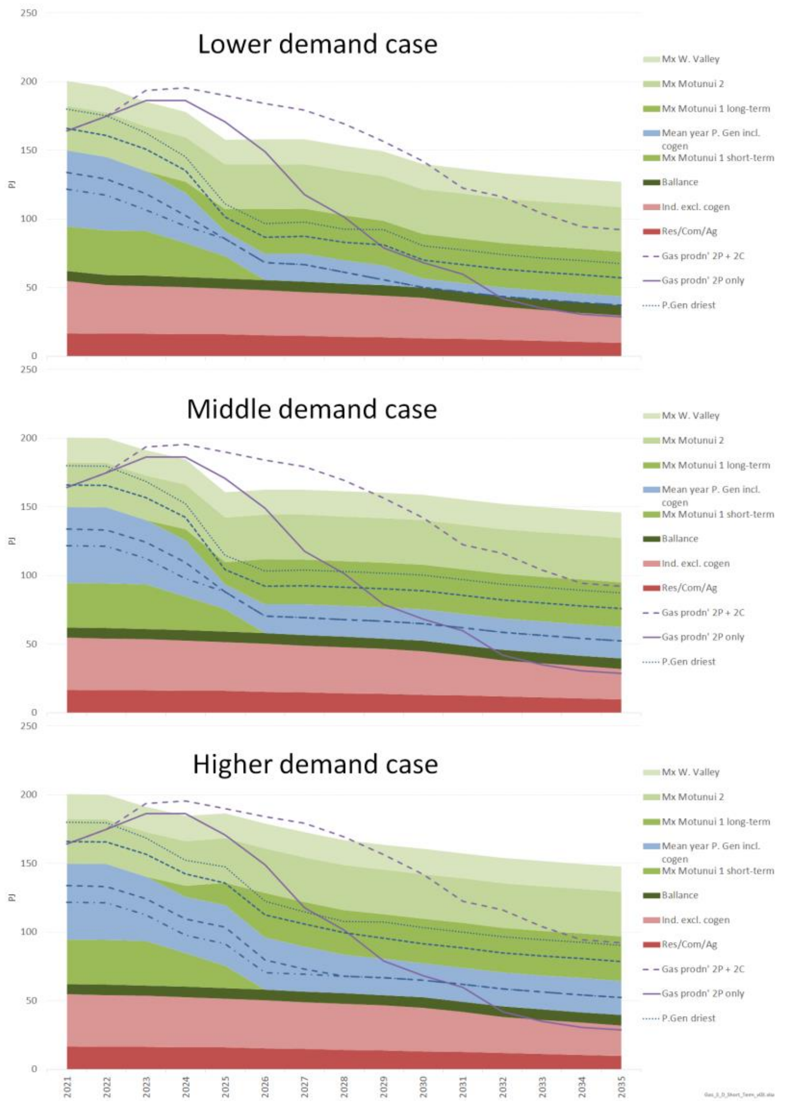
### 4.5.4 Outlook for 2022-2035 under alternative demand cases

This section discusses the outlook under *alternative demand* cases and assuming the *middle case supply* assumptions apply. The various outlooks are summarised in Figure 20.

The key observations from the analysis are:

- Under all demand cases, gas supply from 2P reserves would be sufficient to satisfy mass market, industrial (excluding petrochem) and power generation usage (mean year) until around 2026.[44]
- Under all demand cases there is headroom to support significant gas use by petrochemical manufacturers until mid-decade, and well beyond if contingent resource is developed.
- The main effect of alternative demand cases is to swap gas use between power generation and petrochemical production. For example, if the Tiwai smelter continues to operate beyond 2024 that will reduce gas available for petrochemical production and vice versa.

***Figure 20: Alternative demand cases (and middle case supply)***




Source: Concept projections

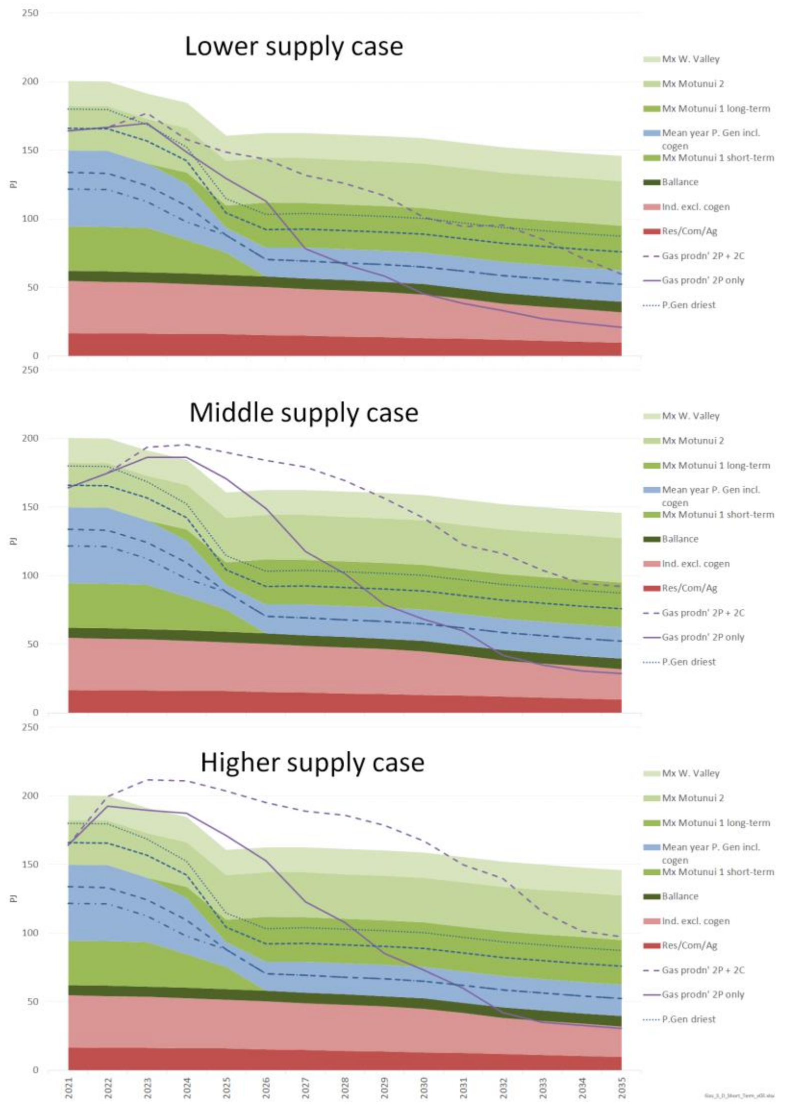
[44] Based on the power generation demand in a dry year and assuming a modest buffer between supply and demand as discussed in the previous section.

### 4.5.5 Outlook for 2022-2035 under alternative supply cases

This section discusses the outlook under *alternative supply* assumptions if the *middle case demand* assumptions apply. The various outlooks are summarised in Figure 21. Key observations are:

- Under the middle and higher supply cases, gas supply capability from 2P reserves would be sufficient to satisfy demand for mass market, industrial (excluding petrochem) and power generation use to 2027 or later. However, in the lower case there would be insufficient supply from around 2025 unless contingent resources are developed. This is based on the expectation that gas supply capability from reserves will be sufficient to meet demand from the above sectors in a dry year until around 2026. It also assumes that supply includes some buffer as discussed in section 3.6.
- Under all supply cases there is headroom to support significant gas use by petrochemical manufacturers until mid-decade. Greater development of contingent resource (as shown in the higher supply case) would increase the available headroom.
- Even under the lower supply case there is room to run (at least) one Motunui unit until 2032 if contingent resource is developed.

***Figure 21: Alternative supply cases (and middle case demand)***

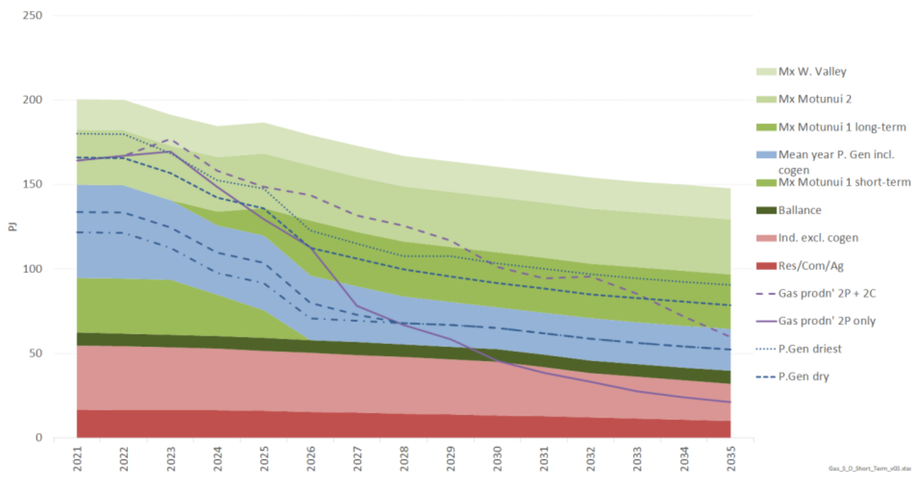



Source: Concept projections

### 4.5.6 Outlook for 2022-2035 – the stress test scenario

This section discusses the outlook under the composite scenario with the tightest conditions – i.e. the combination of higher demand and lower supply cases. The result is shown in Figure 22.

***Figure 22: Composite – the stress test scenario***




Source: Concept projections

Key observations are:

- Even under this stress case, gas supply from 2P reserves would be sufficient to satisfy all demand for mass market, industrial (excluding petrochem) and power generation use until around 2026 based on mean hydrology conditions. However, this date shifts earlier if account is taken of increased gas demand in a dry year. Having said that, the timing would depend on whether gas demand for methanol production has any flexibility in a dry year, noting that we assume Methanex will be reluctant to drop below one Motunui unit in the period 2020-2025.
- Other than in a dry year, there would be sufficient headroom to support gas use for at least one Motunui unit in next five years. The development of contingent resources would extend this horizon to around 2029.

## 4.6 Investment needed to underpin reliable gas supply

It is important to note that all of the supply scenarios described in this chapter will require further investment in supply assets such as wells, field infrastructure and gas processing plant.

The volume of investment is expected to be very substantial. In 2020 Gas Industry Co estimated that the sector will need to invest $300-$500 million every 3 to 5 years to produce existing reserves and maintain production levels. Some industry experts project an even higher annual amount. For example, Enerlytica recently projected that over $2 billion would be required during the 2020s to maintain current production levels.

Whether that investment occurs will be influenced by the willingness of wholesale customers to sign gas purchase contracts, especially longer term agreements. Without the revenue assurance provided by such contracts, gas producers are unlikely to be able to commit the capital sums needed to underpin new investments.

As shown in Table 2, gas users vary in their ability and willingness to enter into contracts to purchase gas. Gas retailers (acting to supply mass market users) and industrials generally have fairly predictable annual demand, and will often be able to contract for 1-3 years ahead to secure their needs. While they have small individual volume needs, in aggregate they represent a sizeable volume of potential sales.

Power generators (including cogeneration owners) can also be sizeable users of gas, but demand from this segment is increasingly for flexible fuel to meet peaking/dry year requirements. While power generators can have a relatively high willingness to *pay* at times, they have shown limited willingness to *contract* ahead. This is because gas demand for power generation is very sensitive to changes in the electricity supply/demand balance and related factors such as the cost of coal. In recent years power generators have been reluctant to enter into contracts with firm annual deliveries and/or longer terms because these do not provide the needed flexibility.

The only segment of demand with a sizeable volume requirement, a stable usage profile, and an ability to contract for five years or more has been petrochemical manufacturing.

***Table 2: Willingness to enter into longer term contracts***

| Type of gas user | Projected demand | Comment |
|---|---|---|
| Mass market (retailers) | ~12-17 PJ | Retailers typically willing to contract for around 1-3 years ahead – but reluctant to contract longer due to uncertainty over market share. Requires some within year flex. |
| Industrial (ex petro chem) | ~30-35 PJ | Typically have relatively flat seasonal profile – and many users contract for 1-3 years |
| Powergen & cogen | ~20-55 PJ | Demand is very uncertain due to weather factors and some structural issues such as future of Tiwai operation. Cogen demand component has been much more stable. |
| Petrochemical manufacturing | Up to 90 PJ | Large source of stable demand which has been willing to contract for up to 10 years |

Looking forward, we expect mass market and industrial gas customers to continue to be attractive to producers as a source of contracts to underpin investment. Similarly, we expect petrochemical producers (especially for methanol production) to remain as a foundation to underpin investment in reliable gas supply.

The demand segment that we think will have the greatest challenge in securing gas is power generation. In particular, power generators may face increasing difficulty in contracting supply for the portion of their demand that is unpredictable because producers will not invest in supply-side assets without relatively firm sale commitments. The question then becomes how power generators obtain their flexible fuel needs during the transition to 100% renewable electricity – a transition that is expected to last for many years. This challenge will become even greater as Genesis reduces coal use at the Huntly power station.

An added challenge in the current environment is that carbon and related policies are yet to be finalised in many areas. Gas sector participants may prefer to delay some decisions until policy is clearer. This could have supply-side implications later in the decade depending on the scale of affected projects and associated lead-times. These points highlight the importance of ensuring a smooth transition, but further exploration of these issues is outside the scope of this report.