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Gas supply and demand projections

24 March 2022

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Executive summary

This report presents an update on New Zealand's gas supply/demand outlook. The last report was published in May 2021. That focussed on the outlook for the (then) forthcoming winter – Winter 2021 – and highlighted the extent of scarcity caused by the unexpected loss of Pohokura output and unexpected continuation of the Tiwai aluminium smelter.

Since May '21, gas producers have been working hard to bring forward their near-term investment plans – in large part in response to this scarcity situation. Updated information from producers suggests gas deliverability will increase by around 18% for Winter 2022 (mid-way between our Medium and High projections for 2022 in our May report), and a further 12% on top of that for Winter 2023. Coupled with projected renewable power generation developments, this analysis – illustrated in Figure 1 – suggests that the scarcity situation will be substantially reduced (although not eliminated) by Winter 2022, and largely eliminated by Winter 2023.

Figure 1: Winter supply / demand balance for 2021 to 2023

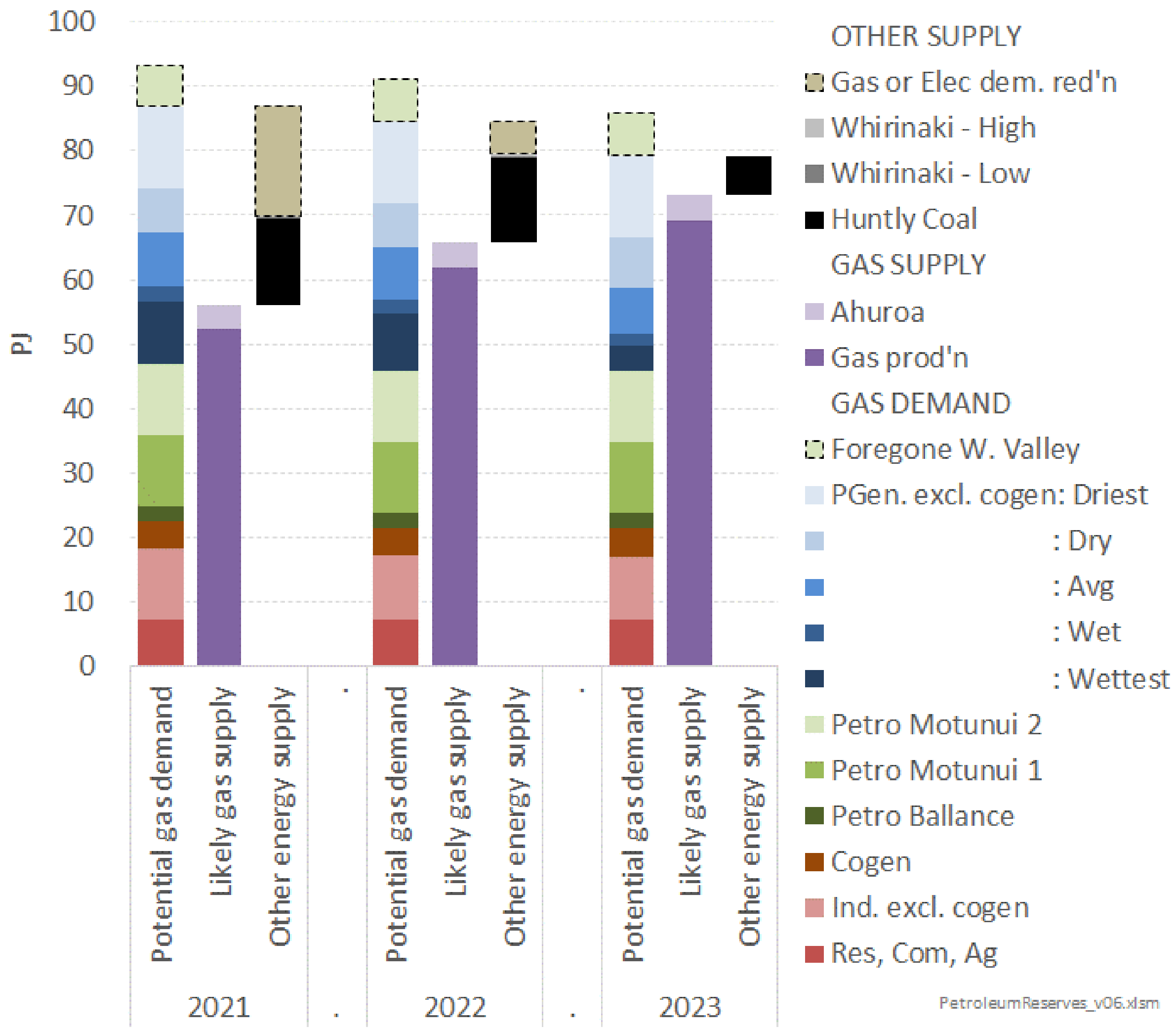
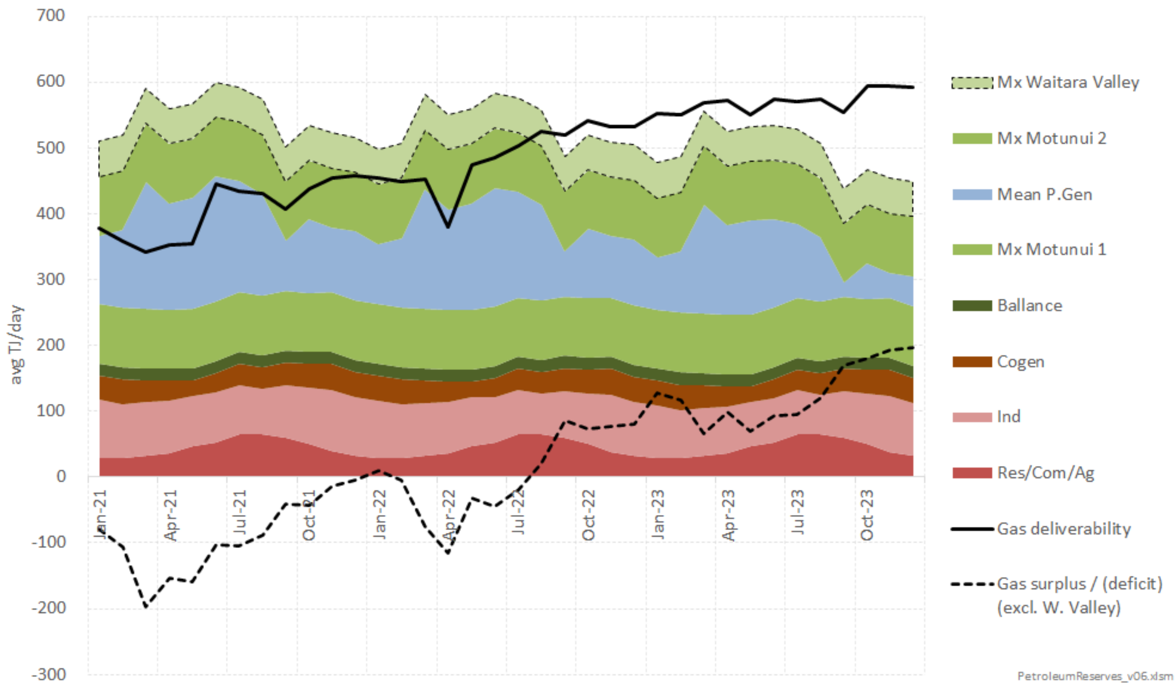


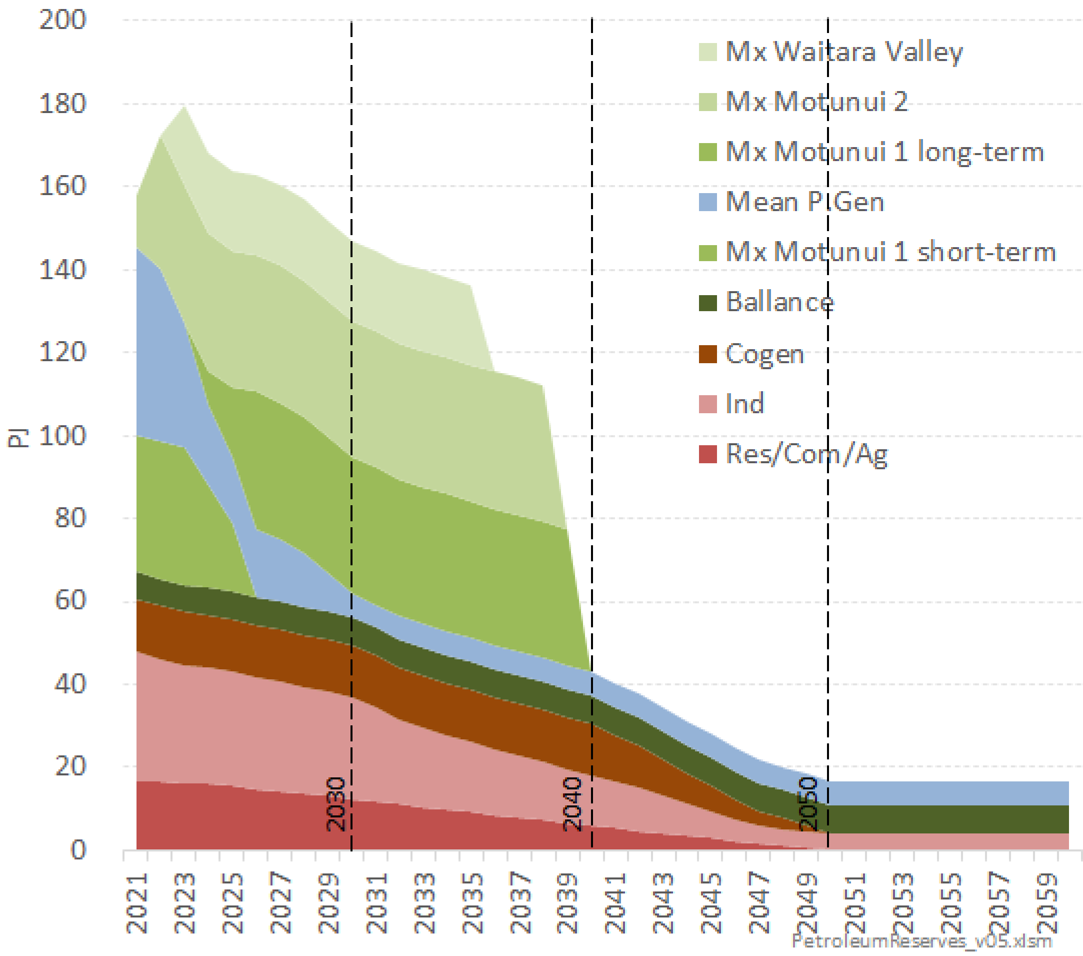
Figure 2 below shows this changing supply/demand balance on a monthly basis out to December 2023. It shows that the projected progressive increases in gas supply deliverability, coupled with increases in renewable generation (which will reduce the gas-fired power generation requirements) will move the market into a more balanced situation by the latter half of 2022, and potentially move to a situation of surplus by the end of 2023 of a scale sufficient to re-start the Waitara Valley methanol train.

Figure 2 Projected monthly supply / demand balance out to 2023



Since our May '21 report was published, MBIE also released producers' updated long-term projections of reserves development, and their estimates of total remaining reserves and contingent resources. These too paint a picture of considerably more gas available to be produced or developed – equivalent to some four years' demand worth of additional reserves and resources. For this study we have also updated our modelling of potential demand and associated supply development. As shown in Figure 3, this indicates that there is sufficient gas to meet higher-value gas users' demands (residential through to power gen in Figure 3) for the very long term, plus continue to supply gas for methanol production – including the re-starting of the currently mothballed Waitara Valley plant around 2023/24 – until the latter half of the 2030s.

Figure 3: Central demand + Central supply projection out to 2060



We explored a range of demand and supply scenario sensitivities, which demonstrated that in all scenarios there was sufficient gas to meet higher value gas users' needs for the very long-term, and that Methanex would likely play the role of the 'balancing demand' to ensure sufficient gas is available to meet higher-value gas users long-term needs: ie, Methanex would exit New Zealand early in situations of lower gas supply availability or higher non-Methanex long-term demands, and vice versa for higher gas supply or lower non-Methanex demands.

However, we highlight that the above outcomes rely on appropriate contracting between suppliers and consumers to manage this transition to a 'non-Methanex' world and, ultimately, a net-zero emissions future. There are likely to be some challenging policy issues to address for this transition, but these are beyond the scope of this study.

1 Introduction

This report presents an update on New Zealand's gas supply/demand outlook.

The last report was published in May of last year. That focussed on the outlook for the then forthcoming winter – Winter 2021. It highlighted the extent of, and the drivers behind, the situation of scarcity that has been facing the gas and electricity sectors since the end of 2018. It further projected, based on a much more limited set of information, that 2022 could face similar degrees of scarcity.

The May '21 report also undertook some projections of possible longer-term outcomes using gas producers' long-term projections provided to MBIE in March 2020.

However, since that time, gas producers have been working hard to bring forward their near-term investment plans – in large part in response to this scarcity situation. In addition, a much more recent set of gas producers' long-term projections have been made available – those submitted to MBIE in in March '21 – and which have significant changes in several areas. There have also been some developments in terms of changes to industrial gas consumption and the electricity generation outlook.

Accordingly, Gas Industry Company felt there would be benefit to stakeholders in producing an updated outlook which captured this most recent information – part of a move by Gas Industry Company to publish the supply/demand outlook on an annual basis (consistent with the recommendation in the recent Gas Market Settings Investigation).

- Section 2 sets out analysis for the near-term. This focusses in detail on the supply security outlook for Winters 2022 and 2023. It also presents information on how the supply/demand balance will likely evolve on a month-by-month basis out to December 2023.
- Section 3 sets out analysis for the longer-term, focussing on the extent to which gas supply is likely to be sufficient to meet demand for the period beyond 2024.

2 Near-term outlook

2.1 Recap of the supply / demand situation for the winter just passed

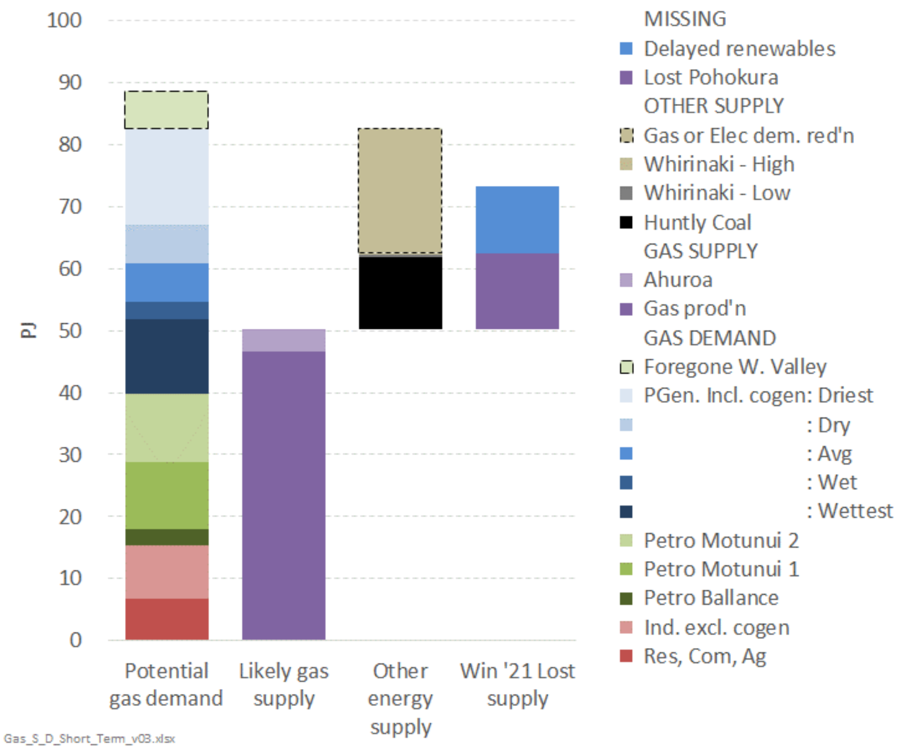
Our May 2021 report identified that, from a supply security perspective, the critical period is the four winter months from June to September: If New Zealand has adequate resources to manage a sustained 'dry' (ie, low hydro) spell during these four months, there will generally be adequate resources for all other periods.

As illustrated in Figure 4 below, our May 2021 report highlighted that for Winter 2021:

- there was a significant shortfall in gas supply to meet demand unless winter hydro generation turned out to be equivalent to the wettest on historical record;
- if Winter '21 turned out to be relatively 'dry' (as indeed was the case) there would be a need for significant coal-fired generation at Huntly, coupled with demand curtailment of major gas and electricity users. These resources would keep the lights on, but would be accompanied by high gas and electricity prices;
- the cause of this scarcity situation was due to a combination of:
  - the unexpected loss of Pohokura gas; and

– under-build of renewable generation over the past few years due to many years of uncertainty over whether the Tiwai aluminium smelter would exit.

Figure 4: May '21 assessment of outlook for Winter 2021



2.2 Outlook for Winter 2022 & 2023

Our May '21 projection for Winter 2021 was based on updated information provided by gas producers in February/March of that year.

Our May '21 report also estimated possible outcomes for Winter 2022. This used the Winter 2021 information as a base, and projected forward on a Low to High scenario basis using the (then) most-recently published gas producers' projections as a basis factored by judgement based on discussions with producers.

The resultant Low | Med | High projected increases in Winter gas for Winter 2022, were 3% | 7.5% | 23.5%. The Low scenario would have resulted in very similar levels of scarcity to Winter 2021.

However, for this update, we have accessed updated information and assessed the key areas which could change the supply / demand balance for Winter 2022 compared to Winter 2021:

- Gas supply
- Gas demand
  – Residential / Commercial / Industrial
  – Power generation
  – Petrochem

The rest of this section details our approach to projecting each of the above factors and highlights key changes in outlook between the May '21 report and this refresh.

2.3 Gas supply

In response to the current situation of scarcity, there has been considerable effort on the part of gas producers to bring forward the development of their gas reserves.

In October/November 2021, three of the four major gas producers provided their latest projections of the monthly deliverability (net of expected outages) for their fields based on their most up-to-date information at that time. Collectively, these are indicating a 17.5% increase in winter deliverability for Winter 2022 compared to Winter 2021.

For the major gas producer who didn't provide information for this study, and for the other minor fields, we have estimated their Winter 2022 and 2023 deliverability based on their most recently published projections of annual reserves production which they submitted to MBIE in March of this year.

With these other MBIE-based field deliverability projections included, our analysis suggests overall NZ deliverability for Winter 2022 will increase by 18% compared to Winter 2021. This is just over mid-way between our Medium and High estimates in our May study. However, as set out later in section 2.5, although this materially improves matters, it is not sufficient to completely bring supply and demand back into balance for Winter 2022.

Producers are also projecting ongoing investment during 2022 and 2023 which will result in a further 12% increase in Winter deliverability for 2023 compared to that projected for Winter 2022.

2.4 Gas demand

Our demand projection approach set out below applies both to our near-term (2022 & 2023) analysis described in this section, and our longer-term analysis (out to 2035 and beyond) described in section 3 later.

2.4.1 Residential / Commercial / Industrial

Our projections of gas demand for residential, commercial, and industrial consumers take the 2020 MBIE quarterly demand statistics for these segments and project them forward using the 'demonstration path' demand projections produced by the Climate Change Commission (CCC). This demonstration path was based on whole-of-economy economic modelling to determine what changes across the various emitting sectors would likely be necessary to achieve our target of net-zero long-lived gases by 2050. It assumes relatively little short-term gas demand destruction, but this reduction in demand progressively increases from the second half of this decade and beyond. Anecdotally we understand that such a pattern is emerging, with the high carbon price[1] in the NZ ETS starting to affect some industrial gas consumers.

We have not changed our approach for this update except that:

- Revised MBIE statistics for 2020 have resulted in a 0.6 PJ reduction in winter gas demand for this segment.
- Our May 2021 projection had the Marsden Point oil refinery continuing through 2022 and beyond. However, since that time the New Zealand Refining Company has announced the refinery will close this year.

[1] At the time of writing, the NZ ETS forward price is \$81/tCO2 for 2022, rising to \$93/tCO_2 by 2026.

We have assumed this will shut from the end of May 2022, based on the announcement from the refinery that closure would occur during Q2 2022. This will reduce winter gas demand by 0.8 PJ, and annual demand by 2.4 PJ from 2023 onwards.

2.4.2 Power generation

Our demand for gas for gas-fired power generation is calculated as follows:

- Actual 2020 demand for generation is projected forward based on the CCC's projections of changes in electricity demand.
- Two large-industry specific changes are made to these projections:
  - The confirmed closure of the refinery will reduce electricity demand by approximately 0.6%.
  - We consider the potential closure of the Tiwai aluminium smelter on a scenario basis. The CCC projections have the smelter closing on 1 Jan 2025, causing a reduction in the demand for generation by approximately 11.5%.[2] We also have a scenario where the smelter doesn't close in 2025.
- Cogeneration and existing plus committed new renewable generation are subtracted from this demand for generation. There are two changes to our approach and assumptions compared to our May '21 analysis:
  - Kapuni cogeneration and Kapuni gas supply are no-longer projected on a net basis.[3] Treating both on a gross basis better enables modelling which considers changes to both such factors – whether it be increases in Kapuni gas production or, for the longer-term analysis, potential closure of gas-fired cogeneration by 2030 due to '100% renewables' policy dynamics.
  - We are projecting a greater amount of renewable generation coming on-stream for Winter 2022 and Winter 2023 based on announcements from renewable developers. This is entirely due to solar: A small amount of rooftop solar (which we didn't include in our May '21 projection) and a greater amount of utility solar based on the announcements by the likes of Lodestone Energy.

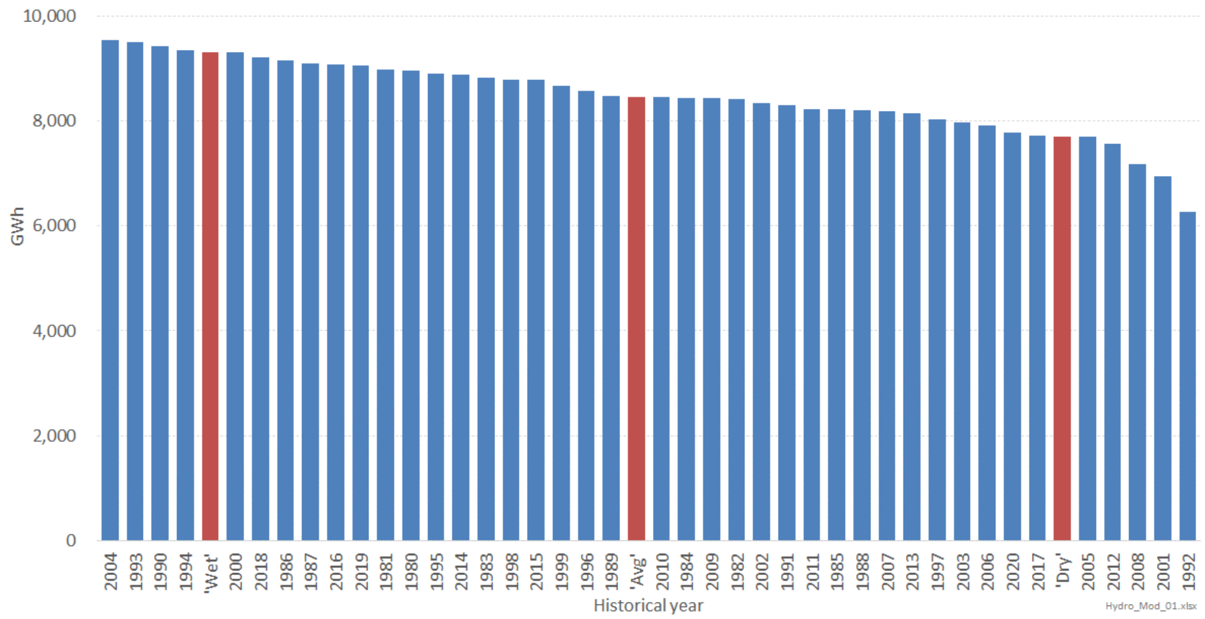
    Partially offsetting this increase in solar, we have pushed back the assumed commissioning date for the Mt Cass windfarm to 1 Jan 2024. We previously assumed this would be commissioned by September 2022.

    Relative to our May'21 projection, the extra amount of generation is equivalent to 0.3% of national generation for Winter '22, and 1.9% of national generation for Winter '23.
- Potential hydro generation is further subtracted from this demand for generation, to give a final 'residual demand' for generation from thermal power stations. Five different levels of hydro generation are considered ranging from the 'wettest' through to the 'driest' conditions. These hydro generation outcomes have been produced using Concept's own proprietary hydro-thermal system models using historical inflow sequences from 1990 through to 2020.[4] As illustrated in Figure 5, below, 'Wet', 'Avg', and 'Dry' correspond to the 90th, 50th, and 10th

[2] This value is lower than the 12.5 to 13% number that is often quoted in relation to Tiwai's share of electricity demand. However, our calculation takes into account the significantly increased losses that would occur transporting South Island electricity to the North Island in the event of a smelter closure.
[3] Kapuni cogeneration is 'behind' the same meter as the Kapuni gas field. This obscures visibility of both the supply and demand dynamic for these significant items.
[4] Note: For this supply/demand update, we have re-run our hydro models using the latest release of historical hydro data from the Electricity Authority. This has led to some (relatively minor) changes due to an extra three years' worth of data being available (2018 to 2020), plus the latest released data set also corrected some historical data relating to spill.

percentiles of hydro generation, respectively, and 'Wettest' and 'Driest' are based on the 2004 and 1992 historical inflow sequences, respectively.

Figure 5: Winter hydro electricity generation



- The residual demand for thermal generation is then met by the projected fleet of thermal power stations: combined-cycle gas-fired turbines (CCGTs), open-cycle gas-fired turbines (OCGTs), and the Huntly Rankine units. Because the different thermal plant have different heat rates (the measure of their efficiency), the amount of gas consumed will depend on which plant are called upon to meet the demand for thermal generation. In scenarios with progressively higher levels of renewable generation, the model progressively retires the two remaining (high-efficiency but inflexible) CCGTs, thereby increasing the average GJ/MWh heat rate and the consequent amount of gas consumed to deliver a given MWh level of generation.

2.4.3 Petrochemicals

The key petrochemicals plant are:

- Methanex's three methanol production trains: Two at its Motunui plant, and one at its Waitara Valley plant
- Ballance Agri-Nutrients' urea production plant.

Historically these have been New Zealand's largest sources of demand – averaging 45% of total demand over the last seven years.

Methanex put the Waitara Valley plant into mothballs at the start of this year due to the ongoing situation of gas shortage following the problems at Pohokura. We assume this plant will remain mothballed until such time as sufficient gas supplies become available to meet all of New Zealand's other demand plus Waitara Valley.

We assume the Motunui methanol trains and the Ballance urea plant will remain open for the foreseeable future while sufficient gas is available.

However, because of the extreme scarcity situation experienced during winter 2021, Methanex on-sold some of its gas-entitlements to Genesis. It is also understood that a planned outage by Ballance resulted in the gas supplier on-selling some of that gas to Genesis during the winter. These transactions enabled Genesis to operate its Huntly power station to keep the lights on over winter, but resulted in lower consumption for petrochemical production during the winter months.

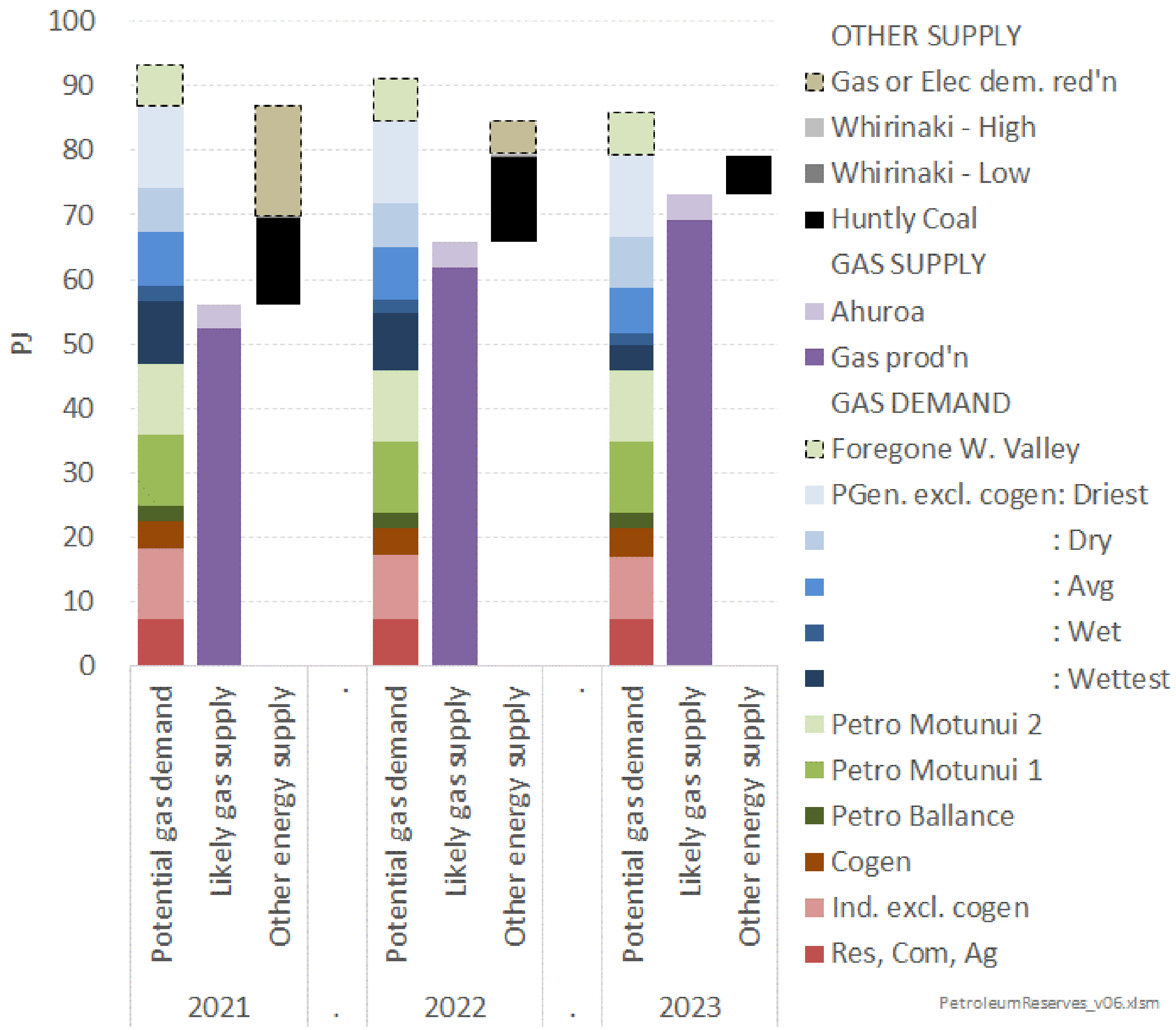
We assume that if the supply / demand balance is similarly tight for future years, there will be similar such trading of petrochemical gas entitlements to higher-value users such as power generation. That said, we understand that there is a relatively high cost to Methanex (and presumably Ballance) from curtailing production – particularly if it is undertaken at relatively short notice – and that this cost would be reflected in the terms of any arrangement for on-selling gas. To this end, arrangements where the terms are agreed well in advance are likely to be lower cost to put in effect, and involve less gas and electricity sector disruption, than deals which are struck 'at the last minute' in response to a scarcity situation which has already begun.

2.5 Net change in near-term supply outlook

2.5.1 Winter four-month supply-demand balance

Figure 6 shows the estimated winter supply-demand balance for 2021 through to 2023.

Figure 6: Winter supply / demand balance for 2021 to 2023[5]



[5] The dark blue band representing gas-fired generation in the 'Wettest' hydrological situation progressively shrinks due to increased renewable generation during this period, reducing the amount of residual demand to

As can be seen, Winter 2021 was extremely tight, with the need to call upon Huntly coal-fired generation even if conditions are 'Wet'. The fact that conditions were 'Dry' meant that demand curtailment was called upon from major gas users (particularly Methanex) and major electricity users (such as the Tiwai aluminium smelter).

However, for Winter 2022 a significant projected increase in gas supply (coupled with a minor decrease in gas demand for power generation) means the supply / demand balance is a lot less tight than in 2021 – although still not completely back in balance. This improvement in the Supply / Demand balance is projected to continue for Winter 2023 due to additional gas supply, plus a more significant reduction in gas demand for power generation due to renewable generation developments.

Further, the above analysis doesn't take account of the potential for plant 'turnarounds' at any of the petrochemical production trains.[6] Were any of those to happen during the winter months this year or next, it would improve the supply/demand balance shown in Figure 6.

Figure 7 provides a different representation of the same data shown in Figure 6. It shows a 'waterfall' representation of what factors have changed between years to deliver the resultant overall shortfall between potential demand for gas and available supply of gas.

This shortfall is not simply the difference between the top of the gas demand bar (excluding Waitara Valley) in Figure 6 and the top of the gas supply bar. This is because it would not be cost-effective to hold supply side assets which would be available to meet gas demand even in the 'driest' hydro sequence. Instead, we have assessed the shortfall against a notional assessment that it would be cost-effective to hold supply side assets sufficient to meet demand up to a 1-in-10-year dry-winter event. ie, this corresponds with the top of the 'Dry' bar in Figure 6.

For more extreme dry-winter events with a return period less frequent than 1-in-10 years, this implies it would be cost-effective to call upon gas and/or electricity demand curtailment to meet this shortfall – noting that, as mentioned above, agreeing the terms for curtailment from major industrial users well in advance is likely to be significantly lower cost, and involve less industry disruption, than curtailing through contracts agreed 'at the last minute' once the scarcity situation has begun.

be met by gas-fired generation. The incremental amount of generation for each of the hydrology situations above the 'Wettest' level remains unchanged. Only if there is sufficient renewable development to completely reduce the need for gas-fired generation in the 'Wettest' hydrology situation, will the amount of gas-fired generation required for the 'Wet' band start to reduce.

[6] Turnarounds are when plant major maintenance and replacement of catalyst is undertaken at petrochemical production trains. These typically last of the order of 6-8 weeks.

Figure 7: Winter supply / demand movements between 2021 and 2023

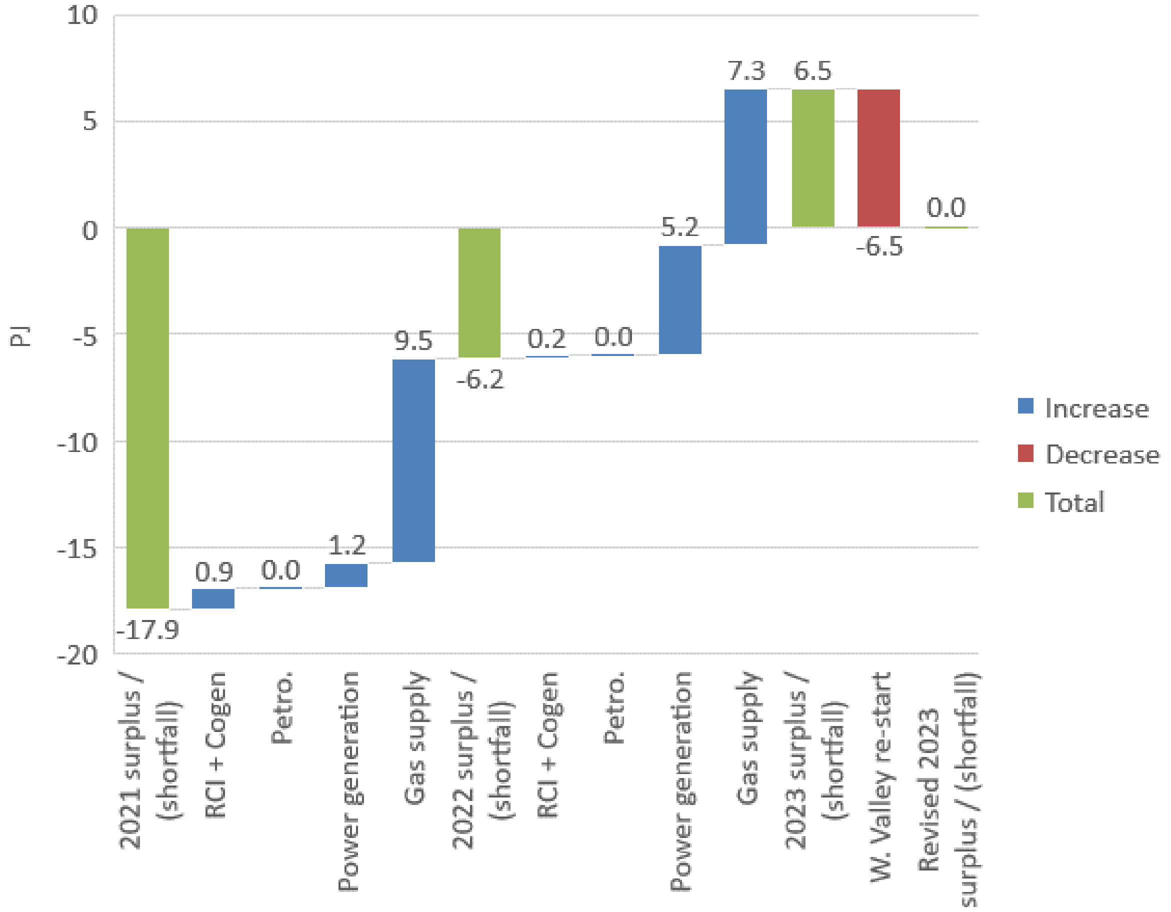


Figure 7 indicates that the economic shortfall for Winter 2021 is likely to be substantially reduced by Winter 2022, largely due to increased gas supply.

It further indicates that the shortfall could be eliminated by Winter 2023 if the additional gas supply and new renewable generation comes forward as projected. Indeed, Figure 7 indicates there will be surplus production capability relative to projected demand, provided Waitara Valley continues to be mothballed. However, if Waitara Valley were to re-start, the chart indicates the market would be almost exactly in balance.

It should be appreciated there is an inherent degree of uncertainty around such projections, with the uncertainty growing the further out the projection goes. Thus:

- The projected development of new renewable generation in 2023 may not occur to the extent modelled if there again emerged significant uncertainty as to whether the Tiwai aluminium smelter will stay or go at the end of 2024.
- The additional development of gas supply resources in 2023 may not occur to the extent modelled.

Nonetheless, this analysis does indicate that there is a reasonable expectation that the tight supply conditions for 2021 should substantially ease over the next couple of years – potentially to the point of enabling the Waitara Valley plant to re-open in 2023.

2.5.2 Peak daily demand

Section 2.5.1 above focused 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 2021.

For peak demand, we use published data for daily withdrawals from the national pipeline system to represent demand, noting this may not capture all gas flows (eg, from Kapuni to the Whareroa cogen plant). The day of highest combined demand across all delivery gates sets our peak daily demand value for a year.

The associated supply from gas fields and Ahuroa gas storage on that peak day would, by definition, almost exactly match demand.[7] This doesn't tell us anything about the extent to which potential supply was greater than demand. To estimate the scale of this potential extra deliverability we have considered gas fields and Ahuroa separately:

- For the potential combined output for gas fields, we have taken each field's P99 daily output across a year, and summed these individual P99 values to give an estimate of the total potential daily deliverability across all fields for a given year.
- For Ahuroa gas storage, we have estimated its peak deliverability from its nameplate maximum rated levels – ie, 45 TJ/day from 2014 to 2020, rising to 65 TJ/day for 2021 following the compressor upgrade in the latter half of 2020 – factored by a function which estimates the extent to which the level of gas in the reservoir (and associated reservoir pressure) affects deliverability. Put simply, if the reservoir is full, it can deliver gas at a greater rate than if it is only a quarter full. Our modelling projects the likely extent to which, as the gas supply / demand balance improves, 'surplus' gas can be used to re-fill the Ahuroa reservoir from its currently relatively low levels. It also effectively assumes that contractual entitlements to Ahuroa's storage will be on-sold to enable Ahuroa's capability to be allocated to the highest value use. Thus, if Contact's entitlement, say, is greater than its need given its current and future gas-using portfolio of generation, but another party may gain greater value out of gas storage given their gas-using portfolio, the modelling effectively assumes that secondary trading will enable such outcomes.

To estimate the peak supply position in 2022:

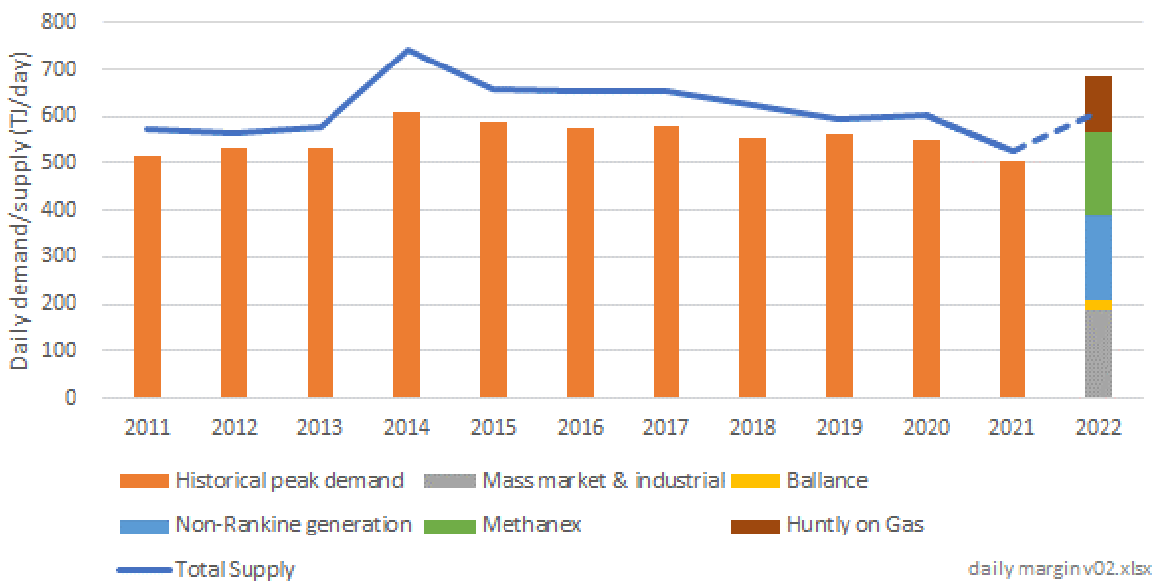
- For gas fields we have taken the combined P99 level for 2021, and factored by the extent to which gas producers have estimated deliverability for July 2022 will be greater than July 2021. This is to ensure consistency with the historical data set – noting that the producers estimated deliverability numbers were on a monthly basis, incorporating the effect of likely outages within a month.

[7] Changing pipeline linepack between days would result in slight differences between total gas field and Ahuroa supply compared to total demand for a given day.

- For Ahuroa we have assumed that the volume in the reservoir will be 1 PJ greater at that start of Winter 2022 than was the case in Winter 2021, giving a small increase in deliverability.

To estimate the potential peak demand for 2022 we choose the individual peak demands for each consumer segment (mass-market & industrial, non-Rankine power generation, Ballance, and Methanex Motunui) over the four years from 2018 to 2021. (19-Aug-2019, 31-Jan-2018, and 24-Jun-19 respectively). This is likely an over-estimate of potential peak demand, but could represent outcomes for an extreme cold snap. We have also shown the amount of gas that would be consumed if two of the Huntly Rankine units were to burn gas for a full day.

Figure 8: Estimated peak daily demand and deliverability



The resulting peak demand and deliverability estimates are shown in Figure 8. The analysis indicates there was a positive deliverability margin of around 10-15% in most years between 2011 and 2018.[8] However, there was a marked reduction following the start of the Pohokura deliverability issues in late 2018. The projected supply increases for 2022 should improve the peak day supply demand balance.

2.6 Within-year change in supply / demand position

While our principal focus has been on supply security over the critical Jun-Sep Winter period for 2022 and 2023, we have also projected how the supply/demand balance is likely to develop on a month-by-month basis over these two years.

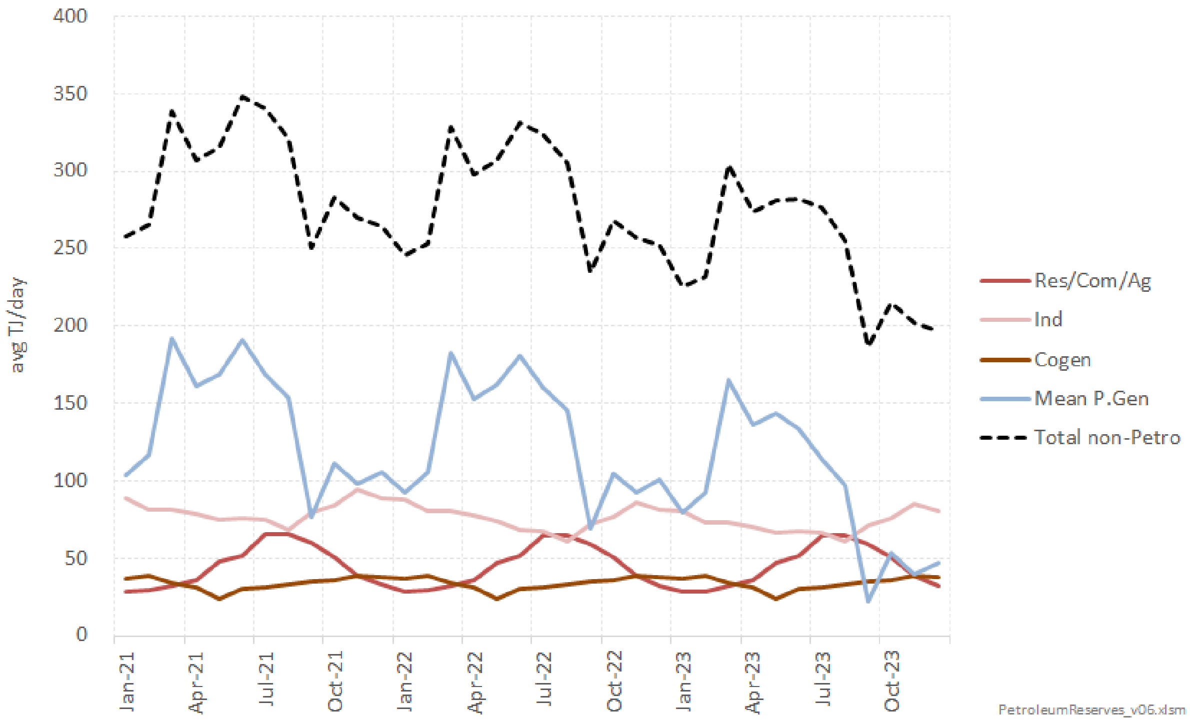
This has required projection of:

- within-year patterns of demand (both gas and electricity)
- the likely month-by-month development of gas supply deliverability
- the likely month-by-month development of new renewable generation.

[8] The headroom was much higher in the 2016, in part due to retirements of thermal power stations.

Figure 9 below shows our projections of monthly non-petrochemical gas demand out to 2023, expressed in average TJ/day consumption.

Figure 9: Projected mean monthly non-petrochem gas demand out to 2023



These projections have been developed based on historical MBIE-reported within-year gas demand for the period 2018 to 2020, and adjusting to take account of projected changes in:

- annual gas demand for Res/Com/Ag and Industrial users
- electricity demand
- new renewable energy developments

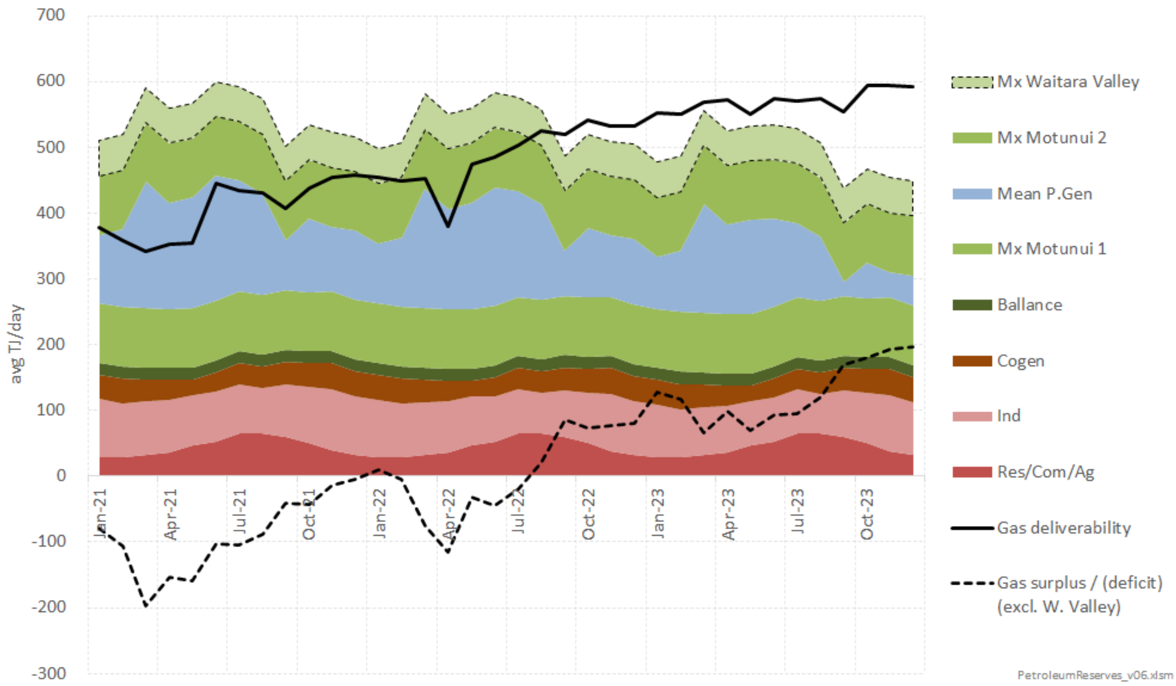
The demand for gas-fired electricity generation is for mean hydrology situations.

The projections show a clear seasonal pattern to gas demand:

- Winter-peaking for Res/Com/Ag – driven by space heating
- Autumn/Winter-peaking for power gen, driven by the within-year pattern of electricity demand coupled with the average pattern of hydro inflows and hydro generators' storage capabilities. The drop in power generation demand during 2023 is due to the projected commissioning of new renewable generation projects at a rate which is outstripping electricity demand growth.
- Much flatter within-year demand, but spring-peaking, for Industrial and Cogen demand. This seasonal pattern is predominantly driven by Dairy processing.

Figure 10 combines the data from Figure 9 with projected changes in gas supply deliverability and projected petrochemical demand for methanol and urea production. It also shows the net surplus/(deficit) of gas supply relative to gas demand.

Figure 10 Projected monthly supply / demand balance out to 2023



We've assumed that petrochemical demand for Methanol and Urea production is flat within the year. We haven't attempted to project whether petrochemical trains may be undertaking 'turn-arounds' during this period which would reduce demand.[9] However, as noted previously, we understand that a Motunui turnaround is scheduled at some point this year which will improve the supply/demand balance while it is underway.

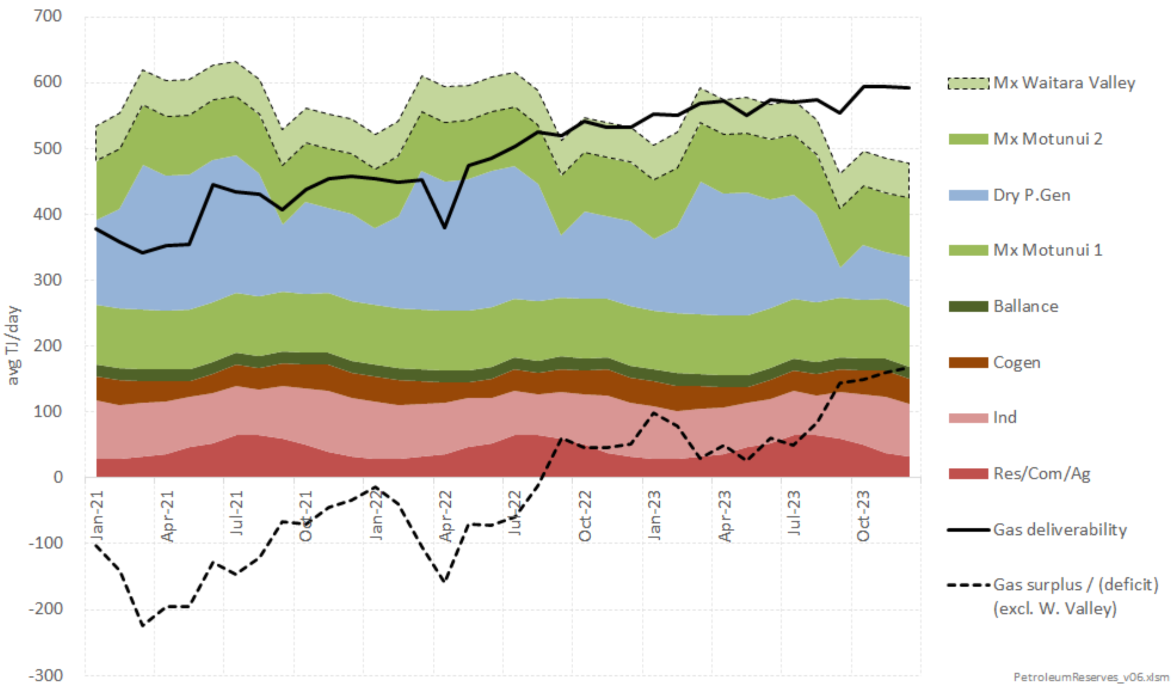
The gas deliverability projection is the sum of projections from gas producers as detailed in section 2.3.

Figure 10 shows that the significant projected increase in gas supply deliverability, coupled with the development of new renewable generation, will move the mean-hydrology supply / demand balance from being in deficit to surplus in the second half of 2022, with the situation improving even more significantly in 2023.

Figure 11 below shows the same information, but with generation at a level consistent with 'Dry' outcomes. ie, the 10th percentile of hydro generation. As would be expected given the underlying scale of thermal generation required during this period, the increase in thermal generation required makes the supply / demand balance tighter in 'Dry' conditions, but doesn't radically change the overall situation.

[9] Petrochemical production facilities undertake periodic 'turn-arounds' every 4-5 years for major plant maintenance and replacement of catalysts. These are understood to last for a period of one to two months.

Figure 11: Projected monthly supply / demand balance out to 2023 assuming sustained 1-in-10 year 'Dry' conditions



3 Longer-term outlook

While upstream parties have provided us up-to-date projections of likely deliverability for 2022 and 2023, they were not asked to provide any updates to the long-term projections of 2P reserves production or the estimates of 2C resources, that they provide each year to MBIE.

As such, we have based our longer-term assessment on the most recent published data – provided by the upstream parties by March 2021, and published by MBIE in August.

However, in discussions with upstream parties, they have verbally indicated that the revised investment patterns described in section 2 are largely bringing forward investments by a year or two, but the overall quantities and long-term patterns of production are not going to be too fundamentally different to the most recent MBIE-published projections.

3.1 Differences to our May report

The longer-term projections in our May report used the (then) most recent published set of gas producers' long-term projections – those that were provided to MBIE in March 2020 – factored by two adjustments:

- Pohokura's 2P reserves and 2C resources were reduced in our central case by 25% to reflect the ongoing issues that Pohokura was experiencing with its offshore wells.
- The projected near-term increase in one other field's output was pushed out by one year. However, the overall level of reserves and resources available to develop was unchanged.

Since our May report, a much more recent set of gas producers' long-term projections have been made available – those submitted to MBIE in in March 2021 and published in August.

This more recent set of data indicates substantially more gas than the earlier projections.

Figure 12 and Figure 13 show how producers' projections of future 2P production submitted to MBIE have changed over time. Three 'MBIE' projections are shown, being those submitted in March 2019 through to the most recent submitted in March 2021. In addition, our revised 'Concept' projection described above for our May GIC study is also shown.

These show that the most recent projections show step-ups in 2023+ production relative to the May '21 projections which are material in the context of the current situation of scarcity. And as described in section 2.3 previously, the even more recent near-term projections from producers provided specifically for this study have this 2023 up-tick significantly brought forward to 2022.

Figure 12: Long-term 2P reserves production projections made at different times

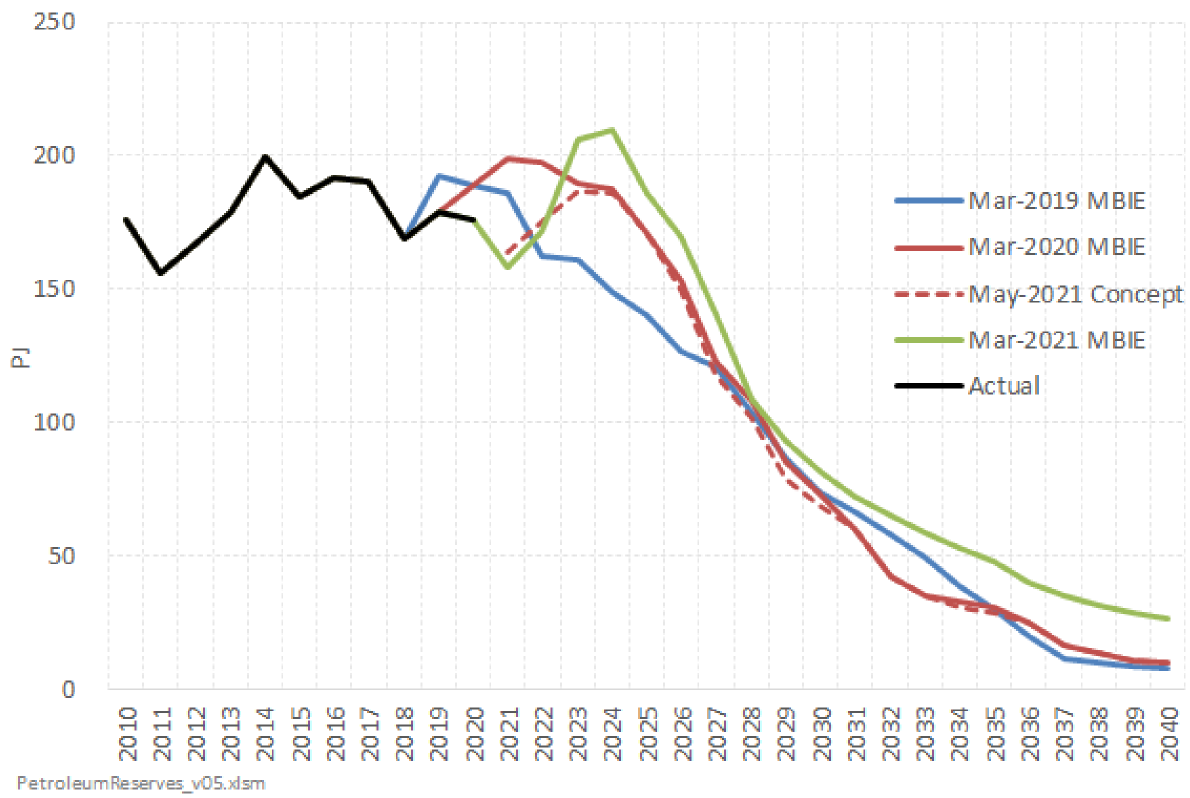
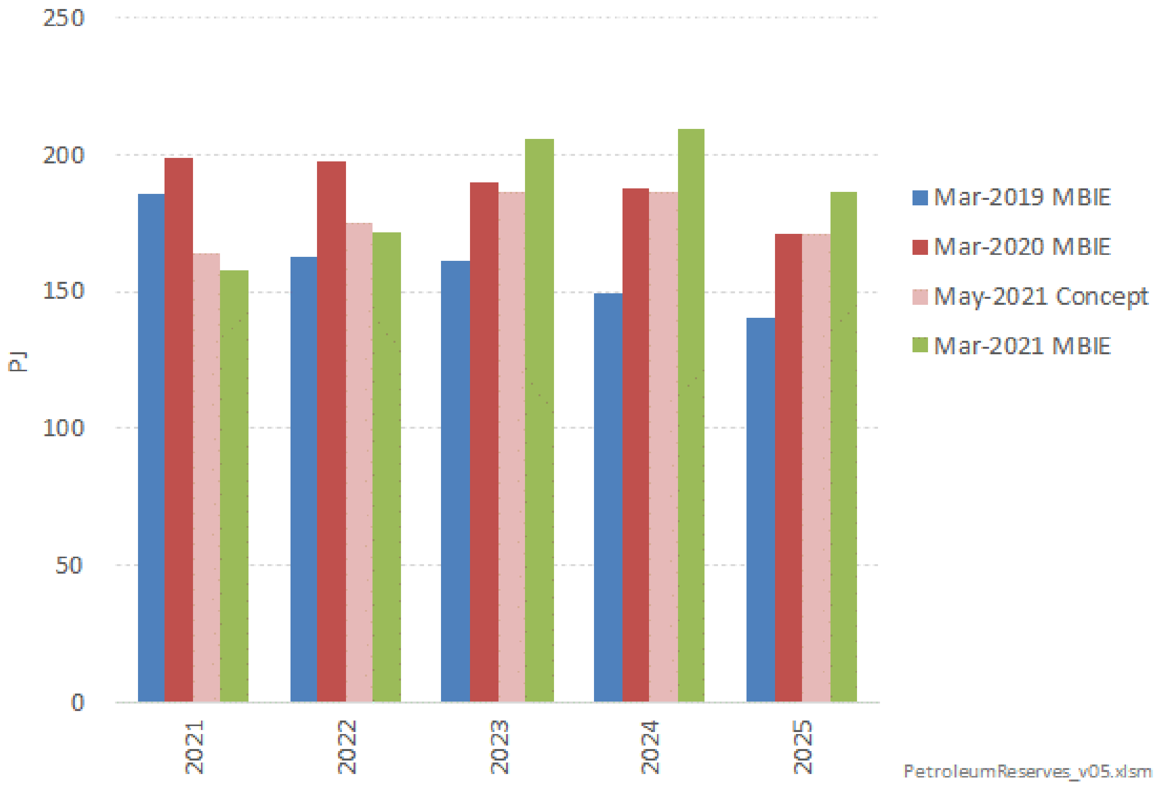


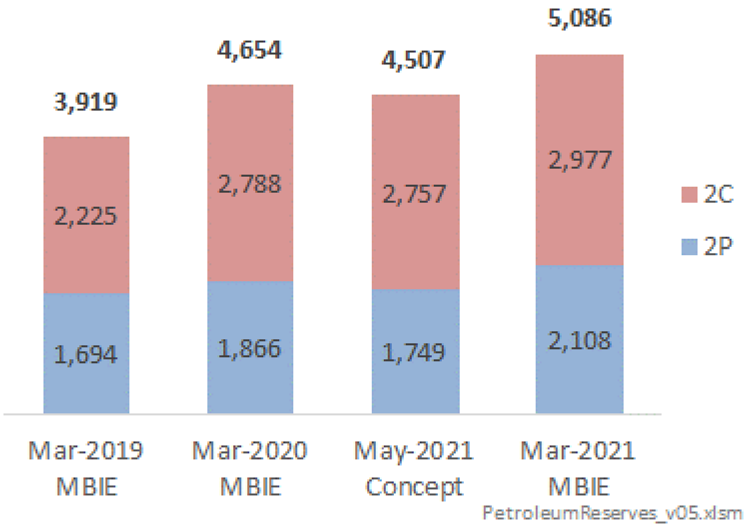
Figure 13 shows the same information as for Figure 12, but only focussing on years 2021 to 2025.

Figure 13: Near-term 2P reserves production projections made at different times



In terms of total reserves and resources potentially available for development, Figure 14 below shows how projections of these have changed across the three MBIE submissions plus our May '21 revised projection.

Figure 14: Projections made at different times of total 2P reserves and 2C resources potentially available for development from 2021 onwards[10]



Overall 2P reserves in the most recent disclosures are 21% higher than was used for our May '21 study, and the 2C resources are 8% higher, giving an overall increase in reserves plus resources that are available for development of 13%. This represents approximately four years' worth of projected 2030 demand (including methanol production) in our central scenario set out below.

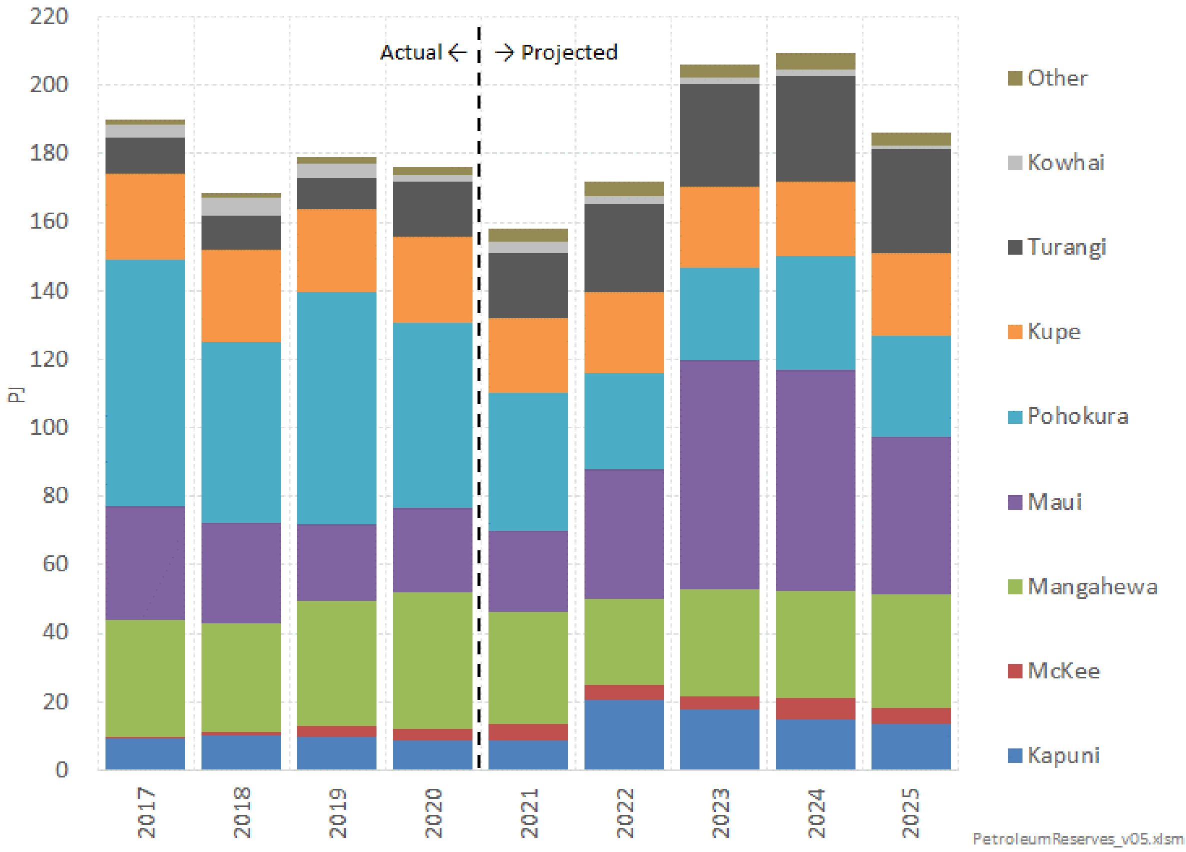
Lastly, as described further below, for this analysis we have better integrated our supply and demand projections through the development of a simple stock model. This has the effect of extending the year that gas is available to meet demand compared to the approach used in the May '21 study which simply overlaid a potential supply profile on potential demand with a simple intersection between the two giving the apparent year when supply will be insufficient to meet demand.

3.2 Medium-term projections

Figure 15 shows the most recent four years of actual gas production, and the projected production levels over the next five years which have been taken from the gas producers' disclosures to MBIE at the start of this year.

[10] The 2P reserves values submitted by producers in March-2019 and March-2020 were estimates of reserves available to produce from 1 January in each year. In order to produce like-for-like estimates of reserves and resources available at 1 January 2021, the actual production in 2019 + 2020 has been subtracted from the Mar-2019 2P estimate, and actual 2020 production submitted from the Mar-2020 estimate.

Figure 15: Combined gas producers' projections of 2P reserves production to 2025



This shows that 2021 represents the nadir for gas production – in large part due to the reduction in output from the Pohokura field.

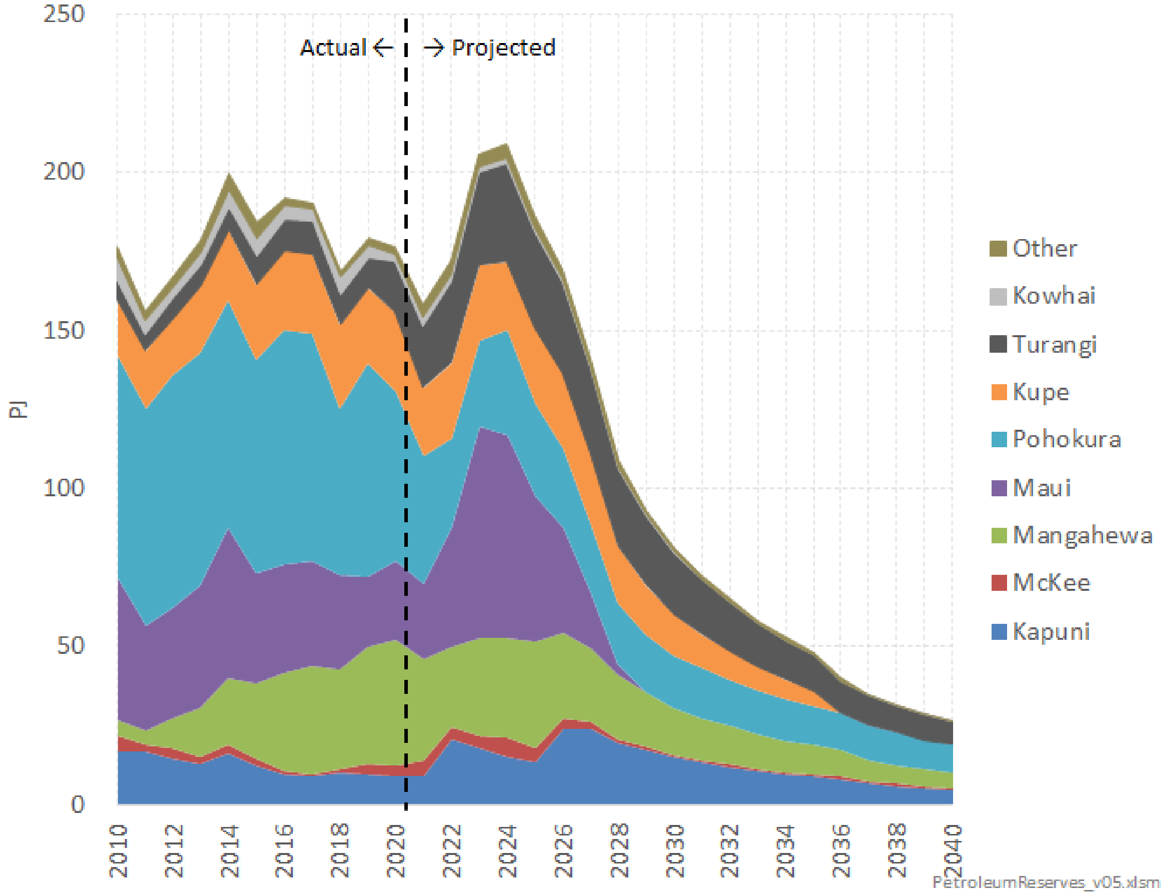
However, projected increases in supply from the Maui field will mean that by 2023 projected gas production levels will have exceeded levels seen in recent history. Indeed, the projected production would be greater than in any year since 2002.

Note: Our near-term analysis in section 2 indicates that 2022 values will likely be higher than these values in Figure 15 *which were based on producers' projections at the start of this year. However, using revised 2022 values could require changes to the latter years' reserve production estimates. We have not attempted to undertake such revisions. Accordingly, for the purposes of this long-term analysis we have used this consistent data set published by MBIE. Given the long-term focus of this section, we believe this to be appropriate.*

3.3 Longer-term outlook

Figure 15 previously indicates that, based on this projection of *reserves* production, the increase will be relatively short-lived with production declining again after 2024. Figure 16 below further illustrates that this projected decline in *reserves* production will be very significant out to 2040.

Figure 16: Combined gas producers' projections of 2P reserves production to 2040



The emphasis on the word 'reserves' in the above paragraph is because there is considerably more gas available to be developed than the accumulation currently classed as 'reserves'. Gas producers also disclose gas accumulations classified as 'contingent resources'. As set out in more detail in Appendix A, these are estimates of additional gas accumulations for which producers consider conditions are not yet right for them to be commercially produced.[11]

However, over time, as gas accumulations classed as reserves get produced and 'used up', the tightening of the supply / demand balance may make it profitable for producers to make investments in contingent resources to enable their development and for them to be re-classified as reserves.

This process of drawing down on reserves and the subsequent investment in, and re-classifying of, resources as reserves has meant that over the last few decades New Zealand has had a constant bow wave of roughly 2,000 PJ of 'remaining' reserves with a projected decline profile similar to that shown in Figure 16.

[11] For example, a producer may assess that consumers are unwilling to contract forward for a sufficient length of time, and at a sufficient price, necessary for the producer to undertake the investment to develop the resource.

As of 1-Jan-2021, producers estimated there was a total of 2,108 PJ of remaining reserves at a 50% level of probability (so-called '2P' reserves), and 2,977 PJ of contingent resources at a 50% level of probability (so-called '2C' resources).[12]

In addition, there is a third category of gas accumulation called 'prospective resources'. As also set out in Appendix A, these are quantities of gas that are estimated to be potentially recoverable, but have not been discovered yet via drilling. Such estimates may be based on high-level statistical evaluations, through to estimates with greater degrees of confidence based on actual seismic data.

The total of all reserves plus contingent and prospective resources is known as 'gas-in-place'. (Inclusion of reserves already produced gives the figure for 'gas *initially*-in-place').

Producers are not required to disclose their estimates of prospective resources for a field. However, since 1 January 2014 (the first date when producers were required to disclose their estimates of contingent resources) the total amount of ultimately recoverable reserves and contingent resources from existing fields has increased by 2,113 PJ. Some of this may have come from the amount of reserves and contingent resources turning out to be significantly greater than the P50 estimates made in 2014. However, statistically, the vast majority of this additional gas will have come from prospective resources which have been subsequently 'discovered' through drilling in accumulations which look prospective based on seismic studies.

It is not known how much additional prospective resources are estimated to exist for New Zealand's current gas fields.

It should be noted that some of these contingent and prospective resources will be uneconomic to develop – albeit to varying degrees based on the threshold gas (and oil) price at which such development becomes economic. However, if the history of changes in reported 2P reserves and 2C resources in New Zealand is any guide, in addition to reserves, it is likely that an amount of gas equivalent to the majority of gas currently classed as contingent resources could be developed if there was demand willing to pay prices seen historically (approximately $6/GJ). This would significantly extend the time at which production could continue at the levels projected for 2023 and 2024.

To get a feel for the extent to which the development of accumulations classed as resources may extend the time when production could continue at high levels, we have done some simple modelling which conservatively assumes that 50% of reported 2021 contingent resources are developed with a production profile that merely extends the point of highest projected production for a time until decline is inevitable, with the subsequent decline profile matching that as reported by the producers in Figure 16. This is the same approach and central assumption that we used for our May analysis – albeit the May analysis was using an older set of reserves and contingent resource values as set out in section 3.1.

The resultant production profile is shown in Figure 17.

[12] The 50% probability means that the probability of there being more gas than these estimates is the same as the probability of there being less gas than these estimates.

Figure 17: Projected production profile including simple development of 2C resources

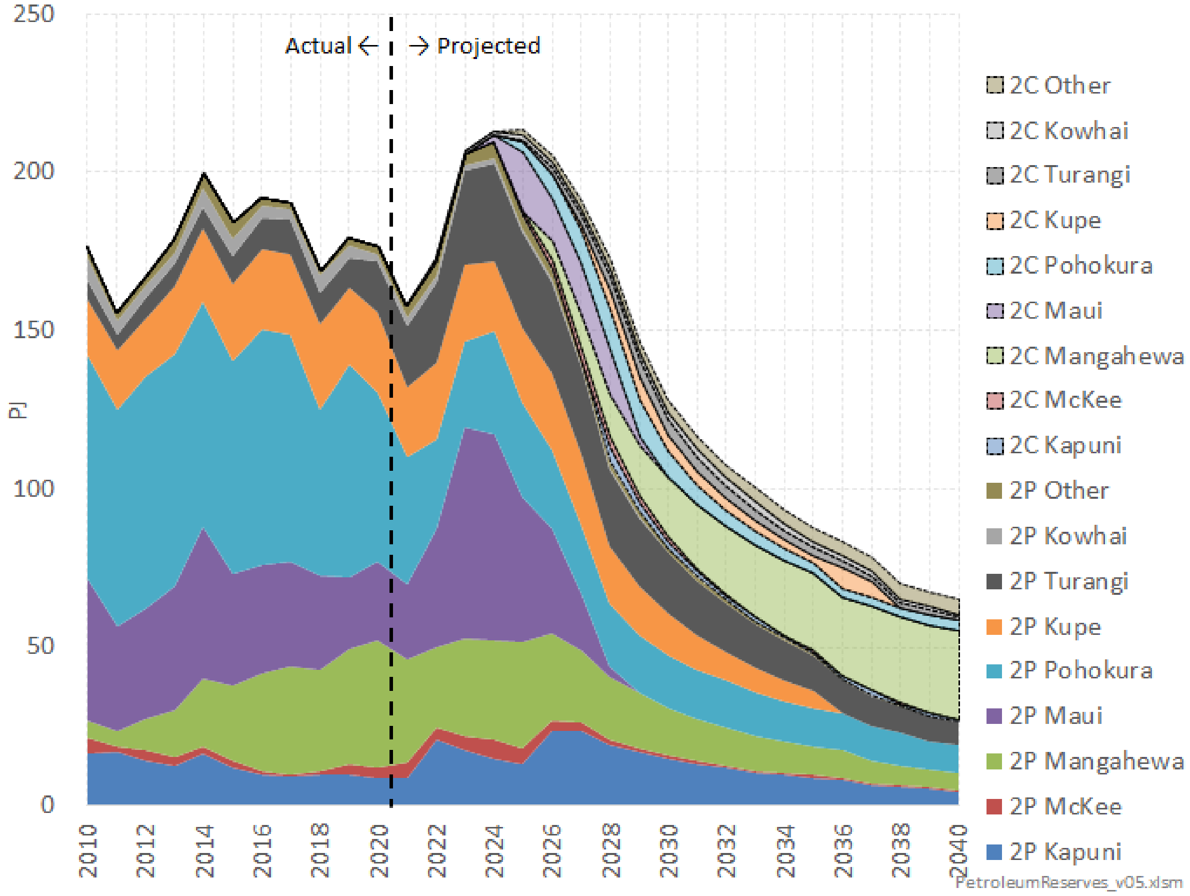
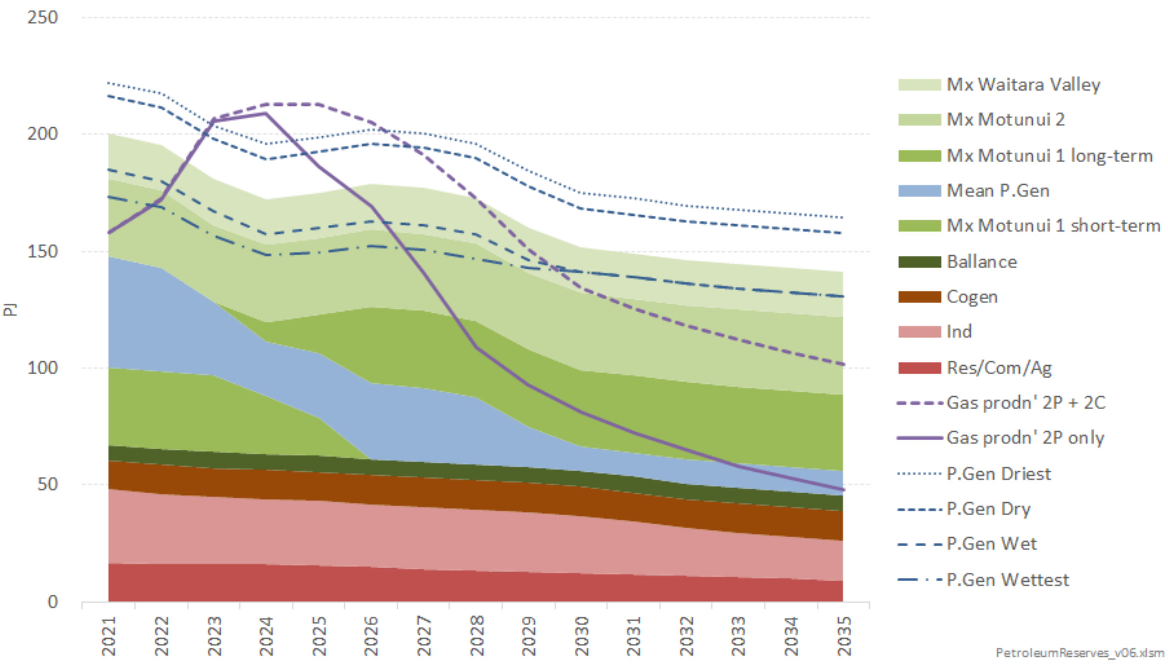


Figure 18 takes the projected 2P reserves and 2C resources production from Figure 17, and overlays them on our central projection of gas demand out to 2035, using the demand projection methodology described in section 2.4 above.

Figure 18: Central gas demand projection overlaid with simple gas production projection



The blue-shaded power generation segment is the mean across all possible hydrologies. In addition, the dotted lines above and below the top of the Waitara Valley segment shows how much gas would be required if a year turned out to be drier or wetter, respectively, than in a mean hydrology situation. The electricity generation scenario is consistent with the CCC's recommendations: reaching 98% renewables by 2030 (95% if gas-fired cogeneration is included).

Additionally, our central projection assumes that the Tiwai smelter will continue beyond 2025 due to the relative competitiveness of producing low-carbon aluminium in New Zealand compared to other international locations. This extension of the Tiwai smelter is projected to increase gas-fired generation in the years 2025 to 2028 as the extension of the smelter beyond 2024 is not certain, thereby leading to a suppression in renewable investment in the years leading up to 2025 relative to what would occur if Tiwai extension was known in advance with absolute certainty.

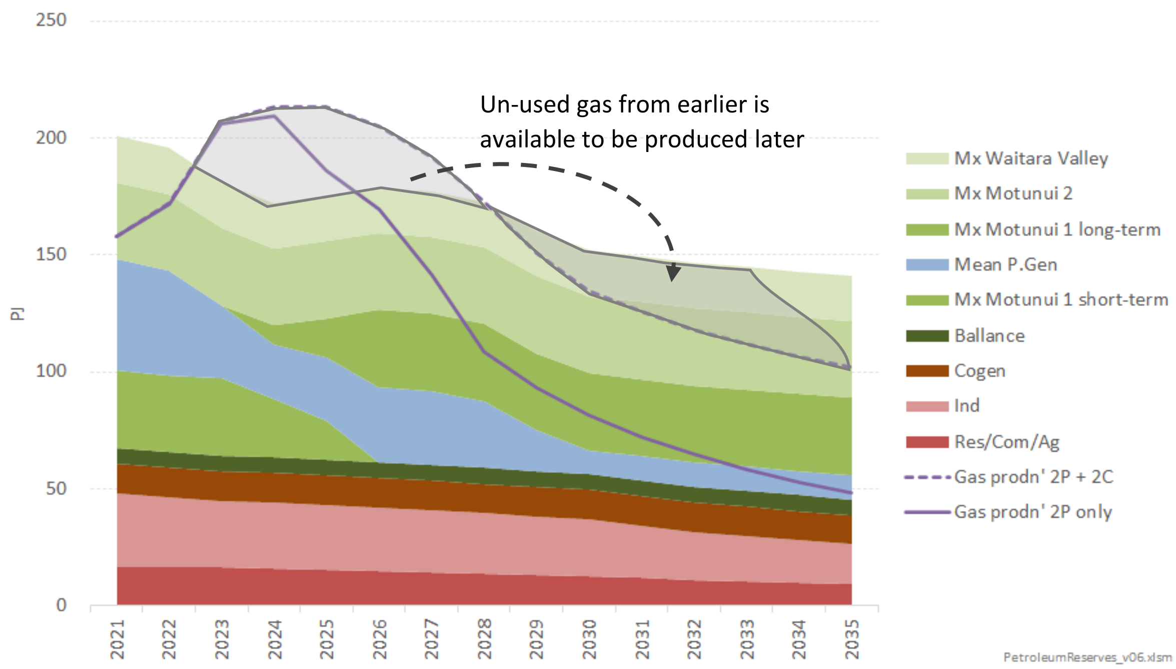
The ordering of the demand segments is intended to reflect a simple hierarchy of gas-using value. Thus, the highest value segments are the residential, commercial, industrial, and cogeneration segments. At the other end of the spectrum is demand for petrochemical manufacturing – particularly methanol production. This is likely to be the most price sensitive segment, and the first to exit if there is insufficient supply available to meet demand.

The chart also shows gas demand for one Motunui methanol 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).

One of the key take-aways from Figure 18 is that the current situation of scarcity is now projected to soon pass – a conclusion that is consistent with our near-term analysis in section 2. Not only might this mean that both Motunui methanol trains may be able to operate close to capacity in 2022 (except if it's relatively Dry), but by 2023 there should be sufficient gas available to re-open the currently mothballed Waitara Valley plant. Indeed, Figure 18 is indicating that if production occurs as producers predict, there will be *too much* gas – even if Waitara Valley were re-started. Further, this glut is likely to continue to 2028 if contingent resources are developed at the rate projected in Figure 18.

Accordingly, a more likely pattern of development will be one where reserves and resources are developed at a rate which will satisfy projected demand. Based on the central assumption that 50% of currently reported contingent resources are capable of being commercially developed, and that no prospective resources are developed, Figure 18 implies that there would be sufficient supply to meet demand – including operating all three methanol trains at full production – for a much longer period than indicated by the '2P+2C' curve. This is illustrated in Figure 19 below.

Figure 19: Central demand projection with illustration of revised supply projection



There is clearly uncertainty over both long-term supply and demand futures. To test the sensitivity of outcomes, for this updated study we have developed our supply / demand model further to project likely development of NZ's gas resources given expectations of future demand and available supply resources.

The model works as a stock model with a starting stock of reserves and resources that could be developed. It also has within it

- the collective field decline profiles as shown in Figure 16.
- a projection of demand out to 2060 from high-value uses of gas – everything from residential up to power generation in Figure 18 and Figure 19.

Each year it determines whether there is sufficient gas available to produce to meet the demand for methanol production without jeopardising the ability to meet future high-value demands for gas out to 2060 given the remaining stock of reserves and resources, and given the decline profile of gas fields.

If there is sufficient gas, the model produces enough gas to meet methanol production. If not, it progressively closes the methanol trains – starting with Waitara Valley and moving down through the two Motunui trains.

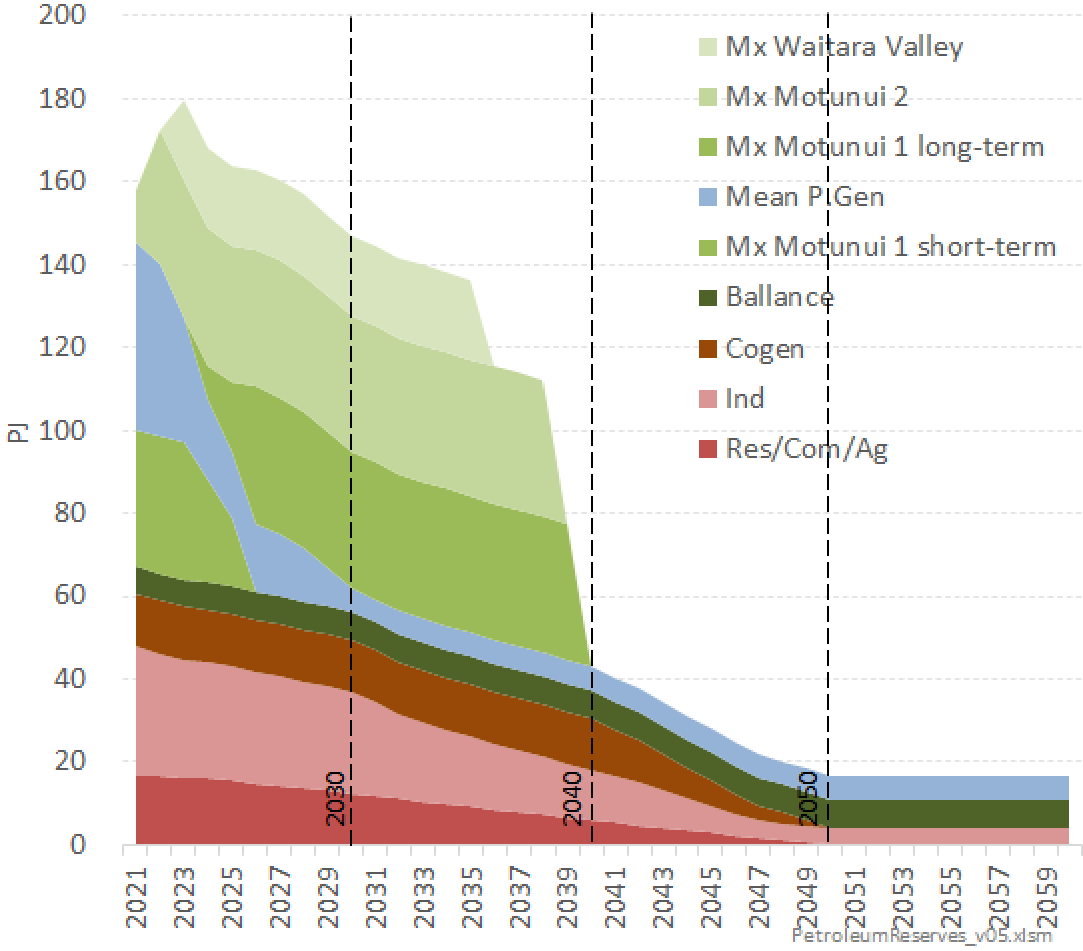
To test the sensitivity of outcomes we have varied both future high-value demand and available supply on a Low / Central / High scenario basis as set out in Table 1.

Table 1: Long-term scenario parameters

	Low	Central	High
Demand			
Res/Com/Ind	Climate Change Commission (CCC) demonstration path scenario		Average of CCC 'demonstration path' & 'current policy reference' scenarios
Gas-fired cogeneration	Shuts by 2030	Shuts by 2050	Shuts by 2060
Tiwai	Exits in 2025	Stays with advance notice	Unexpectedly stays
Electricity generation (excl. cogen) 2030+ target	100% renewable	99% renewable	97.5% renewable
Supply			
% of 2021 reported contingent resources developed	25%	50%	100%

Figure 20 shows the results of our combined Central demand and supply scenarios.

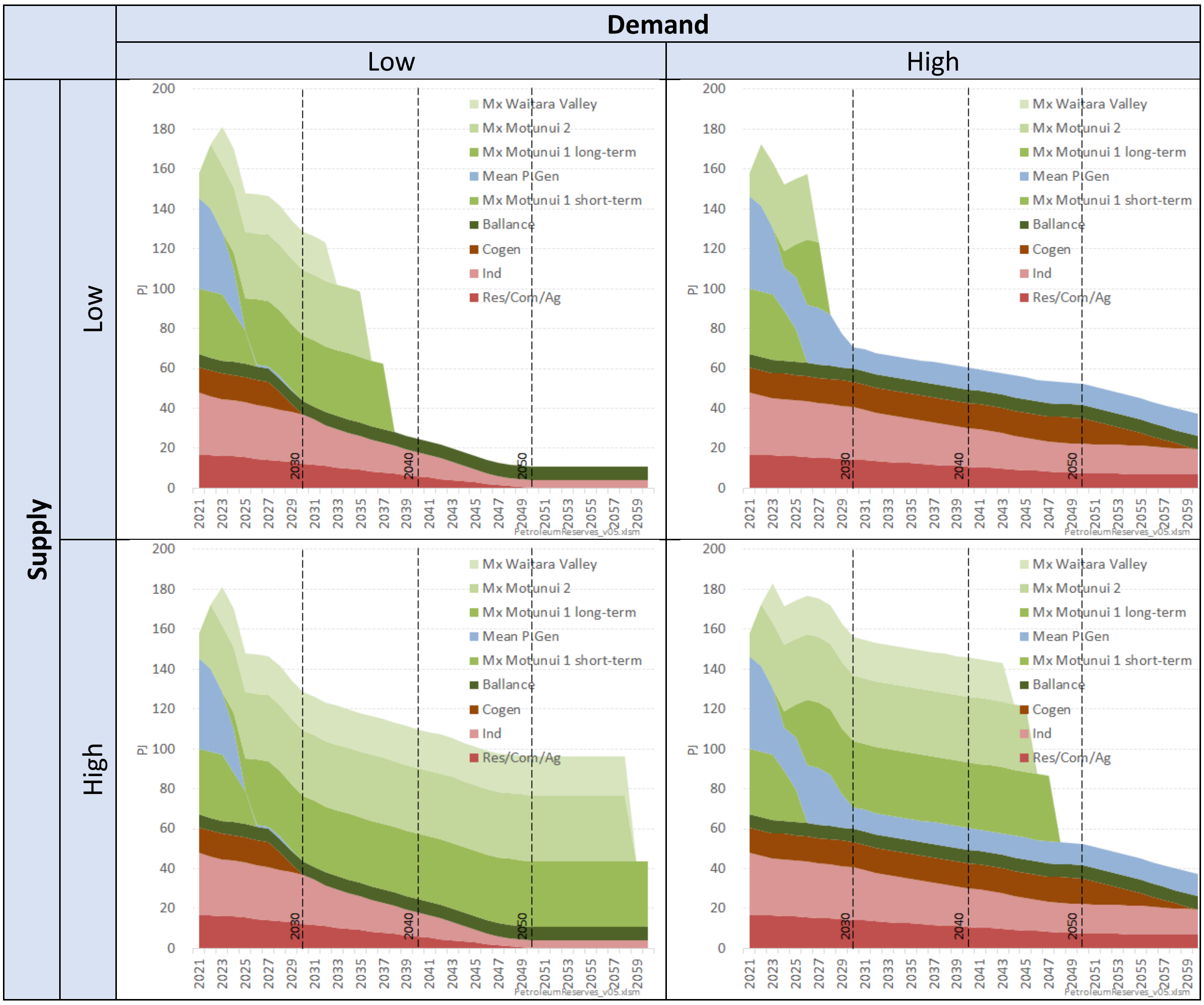
Figure 20: Central demand + Central supply projection out to 2060



This shows that if 50% of contingent resources were developed, there would be enough gas to continue operating the methanol units till the latter half of the 2030s, and still have enough gas to meet demand for the higher value gas uses out to 2060.

The results of the Low / High sensitivity combinations are shown in Figure 21

Figure 21: Low / High combinations for gas supply & demand out to 2060



The immediate take-aways from the above analysis are:

- In all scenarios, there is sufficient gas in New Zealand's existing fields to meet the demands from high-value gas users for the very long-term.
- Methanol production will likely be the 'balancing' item in relation to future demand and supply:
  - if demand for higher-value gas users is higher in the long-term, methanol production will need to cease sooner – and vice versa if high-value demand is lower; and
  - if there is less gas available to produce, methanol production will need to cease sooner in order to 'ration' supply to higher-value users – and vice versa if there is more gas available to produce.

However, all the above scenarios will require ongoing investment in developing the reserves and resources to meet demand. For example, 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 (approximately $200m per year) to maintain current production levels.

Gas and oil prices over the past decade have certainly provided sufficient revenues to support such investment. For example, we estimate the revenues earned by New Zealand's gas-producing fields equated to approximately $1.3 bn in 2020.[13] While we do not have data on operating costs, it seems likely that the revenues after opex were significantly greater than the $200m/yr capital investment requirement estimated by Enerlytica.

However, such prices were also underpinned by longer-term contracts – particularly from the petrochemical producers who have also be willing to take on reserves risk and who have thus done much of the 'heavy lifting' in terms of contracting forward that other gas users have benefited from.

As and when Methanex eventually exits New Zealand, questions have been raised as to whether the remaining gas demand will be of a sufficient scale to support ongoing investment in development of reserves and resources, or what, if any, price rises may be required to support such a smaller-scale gas supply market. It is beyond the scope of this study to analyse such issues, but this issue, coupled with the issue of ongoing recovery of the fixed costs of the pipeline network from a declining customer base, point to some potentially challenging end-of-industry-life policy challenges over the next couple of decades.

We suspect that non-petrochemical consumers may need to contract forward for longer periods than they have historically done.

Such longer-term contracting may also be desirable for consumers to help manage the risks around the type of unexpected scarcity situation which we are currently experiencing due to the unexpected loss of Pohokura output coupled with the unexpected continuation of the Tiwai aluminium smelter.

Our May report highlighted such contracting issues, and noted that most consumer segments had characteristics which could support longer-term contracting, but power generators faced some particularly challenging contracting issues.

This is because gas demand for power generation is variable and sensitive to a number of factors such as hydrology, changes in the electricity supply/demand balance, and related factors such as the cost of coal. While power generators can have a relatively high willingness to *pay* at times, they have shown limited willingness to *contract* ahead. 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 to manage such variability.

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.

The Ahuroa gas storage facility can provide much of this needed flexibility, but there will be a residual need for supply flexibility.

In this respect, it is encouraging that Genesis has signed a deal with Methanex to enable the on-selling of Methanex's gas entitlements during winter months to cope with potential dry-winter situations, whilst noting, as previously mentioned, that this is likely to be a relatively high cost source of flexibility, and thus only likely to be economic to call upon during periods of significant scarcity.

[13] Revenues were from gas and associated liquid sales.

Likewise, it is encouraging that that Methanex has apparently struck a deal with a thermal generator (or generators) to re-schedule the turnaround at one of its Motunui trains to be in the winter months this year, not shoulder or summer months, to release additional energy during these months of greatest sensitivity to possible 'dry year' events.

However, as and when Methanex exits New Zealand, it will become inherently harder for gas-fired generators to contract for flexible sources of supply.

Appendix A. Classification of reserves and resources

Petroleum field owners 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:[14]

- **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 is 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.

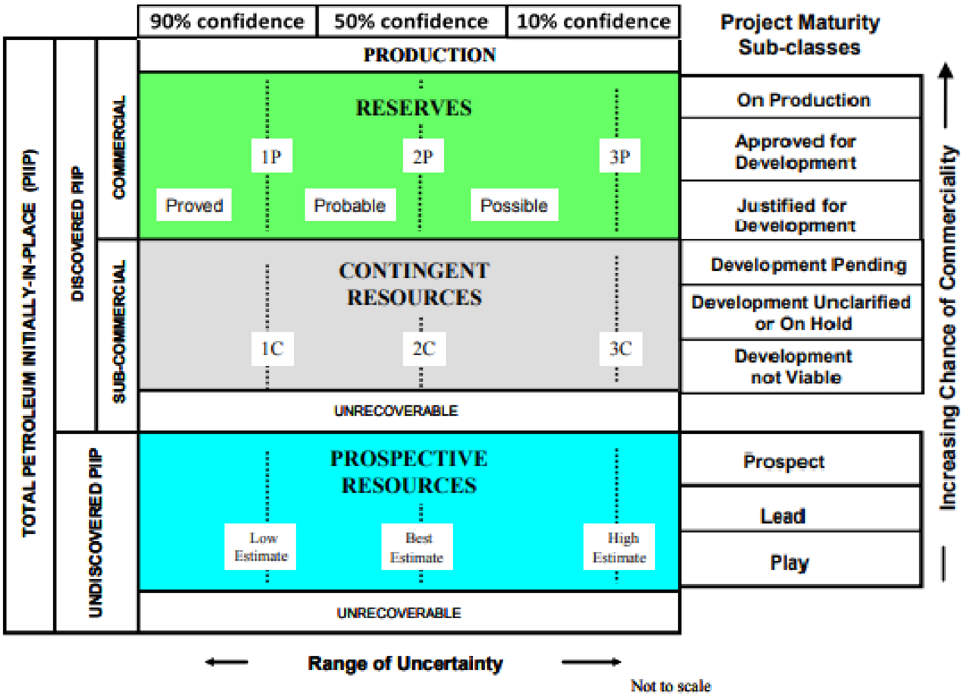
The SPE classification also defines Unrecoverable Resources as those estimated not to be recoverable by future development projects for technical or commercial reasons.

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

The matrix of categories is shown in Figure 22.

[14] 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 22: Matrix of reserve and resource classifications



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